

# Renewable Energy Support, Negative Prices, and Real-time Pricing

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## ABSTRACT

We analyze the welfare effects of two different renewable support schemes designed to achieve a given target for the share of fluctuating renewable electricity generation: a feed-in premium (FiP), which can induce negative wholesale prices, and a capacity premium (CP), which does not. For doing so we use a stylized economic model that differentiates between real-time and flat-rate pricing and is loosely calibrated on German market data. Counter-intuitively, we find that distortions through induced negative prices do not reduce the net consumer surplus of the FiP relative to the CP. Rather, the FiP performs better under all assumptions considered. The reason is that increased use of renewables under the FiP, particularly in periods of negative prices, leads to a reduction of required renewable capacity and respective costs. This effect dominates larger deadweight losses of consumer surplus generated by the FiP compared to the CP. Furthermore, surplus gains experienced by consumers who switch from flat-rate to real-time pricing are markedly higher under the FiP, which might be interpreted as greater incentives to enable such switching. While our findings are primarily of theoretical nature and the full range of implications of negative prices needs to be carefully considered, we hope that our analysis makes policy-makers more considerate of their potential benefits.

**Keywords:** RES support schemes, Induced negative prices, Real-time pricing

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## 1. INTRODUCTION

Many countries around the world strive for high shares of renewable energy sources (RES) in their electricity systems, and fluctuating RES, such as wind power and solar photovoltaics, are likely to make up a major share of most of them. Increasing the share of fluctuating RES, however, confronts policy-makers with various economical, technological and institutional challenges (see Edenhofer et al., 2013). One particular question in this regard, is which support instrument can achieve a given RES target most efficiently.

A major concern is that RES support instruments have a distortionary impact on prices. This impact differs between instruments, and thus also generates different effects on efficiency. One aspect being increasingly debated is the point at which such instruments induce negative prices; see for example Nicolosi (2010), De Vos (2015), and Perrez-Arriga and Battle (2012) and on this issue. The latter make clear that more careful scientific examination is needed. This inspires the

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focus of our analysis, which compares the following two instruments: a subsidy on production, often called a market premium on energy or feed-in premium (FiP), and a subsidy on investment, often called a market premium on capacity or capacity premium (CP). The former can give rise to negative prices up to the (negative) level of the premium, while the latter does not. Common wisdom thus suggests that the FiP would be generally less efficient than the CP due to the deviation from marginal cost pricing. However, as we shall show later, the contrary may hold when targets are defined as relative production shares.

This finding complements previous work by Green and Léautier (2015), who compare the welfare impacts of a production subsidy with either physical or financial dispatch insurance. Importantly, like the FiP the physical dispatch insurance induces negative prices while the financial insurance avoids this by compensating RES supply curtailment with out-of-market payments. They find that when RES targets are defined in terms of absolute capacity, and when consumers are taxed to pay for RES subsidies, then a production subsidy with physical dispatch insurance is inferior to financial dispatch insurance. This is precisely because negative prices occur more often in the case of the former, which reduce the marginal value of RES (market value), and thus require a higher RES subsidy. Consequently the tax to finance the subsidy also increases, which gives rise to additional dead weight losses.

Our work differs from Green and Léautier (2015) in two respects: we define RES targets as relative production shares rather than absolute capacity, and we consider two widely used instruments (FiP and CP) instead of different types of insurances. In particular, the choice of relative production targets is prompted by common policy practice, at least in the EU<sup>1</sup>. Within this setting, we find that in contrast to their results, a FiP can actually be more efficient than a CP despite the presence of negative wholesale prices. This is because respective dead weight losses from a higher levy are outweighed by reduced overall supply cost from lower RES capacity entry. This is possible if targets are defined in relative production terms, such that a higher utilization of installed RES capacities reduces the costs of achieving the targets. We also find that the greater the response of the demand to price, the lower the additional dead weight loss of the FiP in comparison to its positive capacity effect. That is, the higher the share of price responsive consumers, the higher the utilization of RES during hours of high RES supply, resulting in a reduction of required RES capacity. In contrast, Fell and Linn (2013) find for renewable portfolio standards (RPS) that different degrees of demand responsiveness do not substantially affect cost effectiveness. This however may be related to the relatively low proportions of RES examined.

In contrast to the model presented here, Green and Léautier (2015) also consider flexibility restrictions of thermal base load plants and find that financial dispatch insurance is more efficient than physical insurance as it is associated with a lower number of hours with negative prices. Likewise, Rosnes (2014) comes to the same conclusion, comparing a non-price-distortionary investment subsidy (resembling the CP) with a production subsidy that distorts prices (resembling the FiP). In this paper we do not consider such inflexibilities, mainly because we take a long-term perspective over which it can be assumed that the flexibility of thermal generators will increase substantially. This issue is further discussed at the end of the paper.

Our analysis is based on a long-run partial equilibrium model of the electricity sector. We employ the framework developed by Borenstein and Holland (2005) and later used *inter alia* by Allcott (2012) and Gambardella et al. (2016), specifically to analyze the efficiency gains and dis-

1. See EU Directive 2009/28/EC, which sets relative renewable energy targets for each member state for 2020. Several European countries, including Germany, have also set longer-term national renewable energy targets in relative terms.

tributional implications of raising price responsiveness. We draw extensively on the work of Gambardella et al., which analyzes the benefits of real-time retail pricing under carbon taxation and variable renewable energy supply. We loosely calibrate our model to the German market, which is characterized by high shares of fluctuating renewables. We further adopt a long-term perspective, assuming a RES share of 50% in total consumption as a target. Choosing this case is also driven by the fact that the two instruments we analyze are currently prominently debated in Germany in the context of ongoing reform of the support scheme in place (*EEG*); see Enervis and BET (2013) and Agora Energiewende (2014) for exemplary proposals.

While we focus on a particular aspect of FiPs and CPs, investment incentives should also be considered to assess the relative performance of these two instruments in a broader context. Recent work by Aldy et al. (2015) analyzes a natural experiment using data of U.S. wind energy subsidies. They find that where output determines the social benefits of a policy, production subsidies outperform investment subsidies. Capacity payments have been criticized on the basis that investors had just focused on putting “steel-in-the-ground” rather than on optimizing output (Boute 2012). Another important difference between the instruments relates to risk exposure for RES generators; see for example Pahle and Schweizerhof (2016) on this.

The remainder of this paper is structured as follows. In section 2 we describe the general approach, the model and the parameters used. In section 3 we present the results of the base case and sensitivity analyses. In section 4 we discuss potential distortions due to model limitations. The final section concludes.

## 2. METHODOLOGY

### 2.1 General approach

We use a stylized electricity market model with endogenous investments assuming profit-maximizing generators and utility-maximizing consumers. The model includes the two market-based RES support instruments discussed above, i.e. premiums on energy or capacity. These are set to induce a RES share of 50% in the base case. We compute the respective long-term equilibria for different shares of consumers with real-time pricing (RTP) tariffs. In the base case, we assume an RTP share of 10%; we also investigate other exogenously set RTP shares of 1%, 20%, 30%, 40% and 50%, resembling “what-if” policy scenarios. Such an approach—which only considers benefits and not the costs of RTP related to metering infrastructure—is widespread in the literature and has been used for example by Allcott (2012) in the context of demand-side flexibility and capacity markets. In other words, we do not determine the endogenous equilibrium RTP share, but only analyze the effects of exogenously increasing the share of RTP consumers.

We further compare welfare outcomes between the two RES support instruments as well as the benefits of increased RTP for different types of consumers under each of the two instruments. This is done by calculating overall welfare changes between scenarios with different RTP shares. We also study the distribution of welfare effects between different consumer groups. This is done by separating the rents of consumers with RTP tariffs, flat-rate pricing (FRP) tariffs, and those consumers who switch between the two tariffs. In doing so, we are able to determine under which instruments implied incentives to switch to RTP are higher.

### 2.2 Model description

Building on Gambardella et al. (2016) we use a long-run equilibrium model of a perfectly competitive wholesale and retail electricity market, including endogenous investment in generation

capacity. We further pursue a greenfield approach and do not consider existing plant capacities. This is because the main focus of our analysis does not rest on transitional effects of policy induced RES entry but on its long-run welfare effects. Importantly, in the long-run both approaches lead to identical results: if existing capacities are considered then the market would over time adapt to the new regulatory environment—new profitable capacities are built and existing unprofitable capacities are decommissioned—until it attains the very equilibrium computed through the greenfield approach. That is, for any given RES supply share, the thermal technology portfolio would adapt and converge to the equilibrium portfolio as obtained in our simulations regardless of the initial conditions. Of course, the higher the targeted RES share, the more “drastic” are the changes from today’s perspective. But it must be taken into account that respective change would only unfold over decades.

The model further covers a full year on an hourly basis, assumes perfect foresight of all decision makers and is formulated as a Mixed Complementarity Problem (MCP). This MCP constitutes the lower level problem of a Mathematical Program with Equilibrium Constraints (MPEC), the upper level of which is represented by the regulator’s problem of setting instrument levels so that in equilibrium a certain RES share (50% in the base case) is achieved. The MPEC is implemented in GAMS and solved with the commercial solver NLPEC.<sup>2</sup>

### 2.2.1 Supply side

Generators maximize annual profits  $\Pi$  as shown in equation (1) by choosing capacity  $K_i$  for each technology  $i$  and output  $q_{i,t}$  for each hour  $t$  and technology  $i$ , taking into account each technology’s capacity constraint as given by (2). Aside from the revenues from energy sales  $\sum_{i,t} p_t \cdot q_{i,t}$ , profits also include an additional payment for renewables  $j$  in the form of either a feed-in-premium (FiP)  $mp^q$  on renewable output  $q_{j,t}$  or a capacity premium (CP)  $mp_j^c$  per unit of installed renewable capacity  $K_j$ .

$$\Pi = \sum_{i,t} (p_t - mc_i) \cdot q_{i,t} - \sum_i fc_i \cdot K_i + \begin{cases} \sum_{j,t} mp^q \cdot q_{j,t} \text{ (FiP)} \\ \sum_j mp_j^c \cdot K_j \text{ (CP)} \end{cases} \quad (1)$$

$$q_{i,t} \leq K_i \cdot av_{i,t} \quad \forall i, t \quad (2)$$

The Lagrange function of the problem is thus

$$L = \Pi + \sum_{i,t} \lambda_{i,t} \cdot (K_i \cdot av_{i,t} - q_{i,t}) \quad (3)$$

where  $\lambda_{i,t}$  denotes the hourly shadow price of capacity of technology  $i$ . From (3) the Karush-Kuhn-Tucker (KKT) conditions can be derived, which describe optimal firm behavior. The corresponding KKT condition regarding the dual variable  $\lambda_{i,t}$  reads as follows:<sup>3</sup>

$$0 \leq K_i \cdot av_{i,t} - q_{i,t} \perp \lambda_{i,t} \geq 0 \quad \forall i, t \quad (4)$$

2. The GAMS code and all input parameters are available from the first author’s homepage under an open-source license.

3. The symbol  $\perp$  implies orthogonality, i.e.,  $0 \leq x \perp f(x) \geq 0$  is equivalent to  $x, f(x) \geq 0$  and  $x \cdot f(x) = 0$ . That is, if  $x > 0$  then  $f(x) = 0$ , and if  $f(x) > 0$  then  $x = 0$ .

**Table 1: Sets, indices, parameter and variables.**

Symbol	Description	Unit
<i>Sets and indices</i>		
$t \in T$	Time periods	Hours
$i \in I$	All generation technologies	
$j \in J, k \in K, J \cup K = I$	Renewable (j) and fossil (k) generation technologies	
<i>Parameters</i>		
$\alpha$	Share of RTP consumers	[0,1]
$av_{i,t}$	Hourly availability of installed capacity	[0,1]
$\eta$	Price elasticity of demand at reference point	[0,1]
$fc_i$	Fixed generation costs	€/ (MW*a)
$m$	Slope of inverse linear demand curve	€/ (MWh) <sup>2</sup>
$mc_i$	Marginal generation costs	€/MWh
$p0_t$	Interception of linear demand curve	€/MWh
$rt$	Targeted renewable share	[0,1]
<i>Variables</i>		
$\Pi$	Generator profits	€/a
$K_i$	Generation capacity	MW
$\lambda_{i,t}$	Shadow price of capacity constraint	€/MW
$\lambda^{rt}$	Shadow price of RES target constraint	€/MWh
$l$	Levy to finance RES support	€/MWh
$cf_{j,t}$	Hourly RES capacity factor	[0,1]
$mp_j^c$	Market premium on capacity (CP)	€/MW
$mp^q$	Market premium on energy (FiP)	€/MWh
$\bar{p}$	Flat-rate retail price	€/MWh
$p_t$	Wholesale price	€/MWh
$R_t$	Retail price	€/MWh
$q_{i,t}$	Hourly generation	MWh
$Q_t$	Overall hourly demand	MWh
$Q_t^{RTP}$	Hourly demand RTP consumers	MWh
$Q_t^{FRP}$	Hourly demand FRP consumers	MWh
$CS^{gross}$	Total gross consumer surplus	€/a
$CS^{net}$	Total net consumer surplus (welfare)	€/a
$CS^{FRP}$	Net consumer surplus FRP consumers	€/a
$CS^{RTP}$	Net consumer surplus RTP consumers	€/a
$CS^{SWITCH}$	Net consumer surplus switching consumers	€/a

The other KKT conditions depend on the chosen instrument. Under the FiP, the first order conditions with respect to hourly output  $q_{j,t}$  of renewables and fossil technologies  $q_{k,t}$  are as follows:

$$0 \leq mc_j - mp^q + \lambda_{j,t} - p_t \perp q_{j,t} \geq 0 \quad \forall j,t \quad (5a)$$

$$0 \leq mc_k + \lambda_{k,t} - p_t \perp q_{k,t} \geq 0 \quad \forall k,t \quad (5b)$$

From (5a) it follows that the premium on output  $mp^q$  incentivizes generators to supply renewable energy  $q_{j,t}$  even at negative prices up to the point where  $p_t$  equals the negative value of  $mp^q$ —given that renewables have zero short-run marginal costs and the capacity constraint is not binding ( $mc_j = \lambda_{j,t} = 0$ ). The first order condition for investment in capacity reads as:

$$0 \leq fc_i - \sum_t \lambda_{i,t} \cdot av_{i,t} \perp K_i \geq 0 \quad \forall i,t \quad (6)$$

**Table 2: Fixed and variable costs of generation technologies.**

	Annuitized fixed costs ( $fc_i$ ) [€/kW*a]	Variable costs ( $mc_i$ ) [€/MWh]
Wind	136	0
PV	76	0
Base (hard coal)	125	34
Mid (CCGT)	89	64
Peak (OCGT oil)	40	174

That is, firms invest in capacity  $K_i \geq 0$  until the marginal capacity value<sup>4</sup>  $\sum_t \lambda_{i,t} \cdot av_{i,t}$  is equal to the marginal investment costs  $fc_i$ , resulting in zero-profits as implied by the assumption of perfect competition. In other words, if  $fc_i > \sum_t \lambda_{i,t} \cdot av_{i,t}$ , there is no capacity entry of the respective technology ( $K_i = 0$ ).

In contrast under the CP, the premium on capacity  $mp_j^c$  enters the first order condition regarding investment in renewables as shown in equation (7a). The respective first order condition for fossils (7b) remains as under the FiP.

$$0 \leq fc_j - mp_j^c - \sum_t \lambda_{j,t} \cdot av_{j,t} \perp K_j \geq 0 \quad \forall j \quad (7a)$$

$$0 \leq fc_k - \sum_t \lambda_{k,t} \cdot av_{k,t} \perp K_k \geq 0 \quad \forall k \quad (7b)$$

Further, first order conditions for energy output are independent of technology:

$$0 \leq mc_i + \lambda_{i,t} - p_t \perp q_{i,t} \geq 0 \quad \forall i, t \quad (8)$$

Thus, in contrast to the FiP, generators only supply renewable energy  $q_{j,t}$  when wholesale prices are non-negative ( $p_t \geq 0$ ).

Regarding parameterization, we consider three representative thermal technologies (base, mid, peak) and two variable renewable technologies (onshore wind, solar PV). The thermal technologies are loosely calibrated to hard coal (base), natural gas combined cycle gas turbines (CCGT, mid), and oil-fired open cycle gas turbines (OCGT, peak), respectively. While this selection is certainly stylized, it covers the relevant spectrum of technology options with respect to the relationship between fixed and variable costs (Table 2). The cost parameters have been calculated drawing on techno-economic parameters provided in Schröder et al. (2013) and fuel price scenarios of the 2014 IEA World Energy Outlook.

On the RES side, we focus on the two most prominent fluctuating technologies, as these are very likely to contribute most to renewable targets in many countries. In particular, we leave out offshore wind and biomass because of their higher costs and restricted potentials.<sup>5</sup> Hourly RES availability factors are calculated from 2013 German market data. Annual average capacity factors are 18% for onshore wind and 10% for solar PV.

4. Note that  $\lambda_{i,t} \cdot av_{i,t}$  equals hourly net producer surplus per unit of energy sold, that is either  $av_{j,t}(p_t - (mc_j - mp^d)) \forall j$  or  $av_{k,t}(p_t - mc_k) \forall k$ .

5. Explorative model runs that include these technologies indicate that the computation time increases substantially without changing qualitative results.

### 2.2.2 Demand side

Based on the framework developed by Borenstein and Holland (2005), we split consumers into two segments as shown in equation (9): consumers on flat-rate pricing (FRP) having a share of  $1 - \alpha$  and facing a time-invariant price, which in equilibrium equals the demand-weighted average of hourly wholesale prices  $\bar{p}$ ; and consumers on real-time pricing (RTP) having a share of  $\alpha$  and facing a time-variant price, which in equilibrium equals the hourly wholesale price  $p_t$ . Additionally, we assume that total RES subsidies are spread evenly across all consumers in the form of a levy  $l$  per unit of electricity consumed. Therefore, the final retail price faced by each consumer comprises two components: the costs of energy and the costs of RES supports. Total demand  $Q_t$  equals the sum of hourly FRP and RTP consumer demand:

$$Q_t(p_t, \bar{p}, l, t) = \alpha \cdot Q_t^{RTP}(p_t, l) + (1 - \alpha) \cdot Q_t^{FRP}(\bar{p}, l) \quad \forall t \quad (9)$$

We further assume that demand is a linear function of the respective price for both consumer types, and takes the following form:

$$Q_t^{RTP}(p_t, l, t) = \frac{1}{m} \cdot (p0_t - (p_t + l)) \quad \forall t \quad (10a)$$

$$Q_t^{FRP}(\bar{p}, l, t) = \frac{1}{m} \cdot (p0_t - (\bar{p} + l)) \quad \forall t \quad (10b)$$

where  $p0_t$  is the hourly prohibitive price which shifts the demand curve from hour to hour to capture structural demand variations. Retail prices are determined under the assumption that homogenous retail firms maximize profits under perfect competition. That is, retailers buy electricity from generators on the wholesale market and sell it on to consumers making zero-profits. In addition, retailers are obliged by the regulator to collect the levy  $l$  from consumers to finance the RES subsidies. Assuming that retailers do not cross-finance their respective expenses, levies are set so that total premiums paid to RES generators equal total levies paid by consumers. Rewriting corresponding zero-profit condition gives the premium on generation (11) and capacity (12) respectively as:

$$0 = l - \frac{\sum_{j,t} q_{j,t} \cdot mp_j^a}{\sum_{i,t} q_{i,t}}, \quad l \text{ free} \quad (11)$$

$$0 = l - \frac{\sum_{j,t} K_j \cdot mp_j^c}{\sum_{i,t} q_{i,t}}, \quad l \text{ free} \quad (12)$$

Noting that retailers procure energy for both consumer types at the hourly equilibrium wholesale price  $p_t$  determined by the market clearing condition (13), perfect retail competition implies that  $p_t$  has to equal the hourly retail price. Likewise, retailers' zero-profit condition (14) gives that FRP consumers' flat energy price  $\bar{p}$  equals the demand-weighted average of  $p_t$ .

$$0 = \sum_{i,t} q_{i,t} - \alpha \cdot \frac{p0_t - (p_t + l)}{m} - (1 - \alpha) \cdot \frac{p0_t - (\bar{p} + l)}{m}, \quad p_t \text{ free} \quad \forall t \quad (13)$$



$$0 = \sum_i \left( (\bar{p} - p_i) \cdot (1 - \alpha) \cdot \frac{p_i^0 - (\bar{p} + l)}{m} \right), \bar{p} \text{ free} \quad (14)$$

Regarding the share of RTP consumers  $\alpha$  there is no data available for the German market, but there is evidence that it is larger than zero. Namely Agora Energiewende (2015) uses an exemplary bid curve to illustrate that a certain proportion of demand is already responsive to prices (around 3 GW in the particular hour analyzed). Due to this lack of data we assume  $\alpha = 10\%$  in the base case, which approximates mid-run projections in other markets such as PJM (cf., Allcott 2012).

Regarding demand parameters, we calculate the slope  $m$  and the hourly prohibitive price  $p_0$ , using a price elasticity of  $-0.05$  in the base case, and demand-weighted annual average prices and quantities drawing on German market data for 2013. While both the functional form and the value of price elasticity are conventions supported by the literature, there is little evidence for the shape of demand functions for any consumer type. Green and Vasilakos (2010) also use a linear function, but Bushnell (2011), for example, uses a partial log-function and Borenstein and Holland (2005) use an iso-elastic function. Likewise, parameters for own-price elasticity also vary. Both Bushnell (2011) and Borenstein and Holland (2005) use the same value as we do, whereas Green and Vasilakos (2010) apply higher values ( $-0.2$  and  $-0.3$ ). Other work, such as Pineau and Murto (2003), uses even higher values ( $-0.4$ ). Given that modeled prices very much depend on the parameterization of demand, we discuss the effect of alternative price elasticities ( $-0.01$  and  $-0.1$ ) as part of a sensitivity analysis.

### 2.2.3 *The regulator's problem*

The regulator needs to set the levels of the FiP ( $mp^g$ ) and the CP ( $mp^c$ ) respectively so that the RES production target  $rt \in [0, 1]$  as defined in equation (15) is achieved in equilibrium; the asterisk denotes that all prices and quantities are equilibrium levels, and  $mp$  is used as a general form for both premiums.

$$\frac{\sum_{j,t} q_{j,t}^*(mp)}{\sum_t Q_t^*(p_t^*, \bar{p}^*, l, t)} = rt \quad (15)$$

To determine the premium levels, one would need to solve equation (15) for  $mp$ , but this cannot be done in closed form because price and quantities are equilibrium levels. In face of this, we need to determine the levels numerically, which we do by formulating the regulator's problem as a mathematical program with equilibrium constraints (MPEC). The mathematical program simply consists of an equality constraint (15), but for technical reasons a dummy function to be maximized is required, for which we chose gross consumer surplus as given in equation (16) for convenience reasons. The MPEC thus consists of equations (15)–(16) entailing the upper level "optimization" by the regulator and the following equilibrium constraints entailing producer and consumer behavior: supply side equations (4)–(6) in case of the FiP and (4),(7a)–(8) in case of the CP, and demand side equations (9)–(14).

$$CS^{gross} = \sum_t \left[ \alpha \cdot \left( \frac{p_t^0 - (p_t + l)^2}{2 \cdot m} \right) + (1 - \alpha) \cdot \left( \frac{p_t^0 - (\bar{p} + l)^2}{2 \cdot m} \right) \right] \quad (16)$$

Even though we determine levels numerically, basic economic reasoning already allows some inferences about how the premiums are set. To begin with, the implicit shadow price  $\lambda^{rt}$  of



the RES target constraint (16) reflects the marginal social value of each unit of RES production for achieving the target. Intuitively, the level of both instruments depends on  $\lambda^r$ . More specifically, efficiency requires that  $\lambda^r$  is identical for all RES technologies per unit of production under both instruments.

For the FiP this implies that  $mp^g$  is equal for all technologies and identical to  $\lambda^r$ , which simply follows from the relation of social value to production. This does not mean though that only a single RES technology enters the market, i.e. the one with the highest capacity factor to cost ratio. The reason is that market revenues differ for all technologies because of different availability patterns, e.g. PV produces more in high price hours during noon than wind. On this also see Lamont (2008), who derives the long-run marginal value of RES.

In contrast, under the CP capacity is subsidized and hence control is indirect in the sense that even though capacity is subsidized, it is production that creates value. The hourly production of one unit of capacity of technology  $j$  can be expressed using an hourly capacity factor  $cf_{j,t} \in [0,1]$  defined as the ratio of the actual output to the maximal output (capacity) in hour  $t$ , i.e.

$cf_{j,t} = \frac{q_{j,t}^*}{K_j}$ . Note that here again  $q_{j,t}^*$  denotes the hourly equilibrium output and thus constitutes the actual utilization of capacity in contrast to its technical availability ( $av_{j,t}K_j$ ). Since the capacity factor is identical to the marginal production of each unit of capacity, efficiency requires that  $mp_j^c = \sum_t cf_{j,t} \cdot \lambda^r$ . That is the capacity premium  $mp_j^c$  must equal annual production per unit of capacity  $\sum_t cf_{j,t}$  times the uniform social marginal value of RES output  $\lambda^r$ .

From the above it also follows that the capacity premium must differ for technologies if their average availability and thus capacity factors differ, too. More precisely, in our model each unit of wind capacity is more valuable than PV capacity for achieving a given RES production target, that is  $\sum_t cf_{wind,t} \cdot \lambda^r > \sum_t cf_{PV,t} \cdot \lambda^r$ , if wind is relatively more available for production ( $\sum_t av_{wind,t} > \sum_t av_{PV,t}$ ) and thus has a higher output per unit of capacity (capacity factor). Accordingly, a single technology-neutral premium would overpay technologies with low capacity factors (PV) leading to an inefficient outcome.

### 2.3 Ex-post calculation of welfare effects

In a second step we also examine (a) welfare differences between the two instruments for given RTP shares and (b) compare the relative welfare gains from increasing the RTP consumer share  $\alpha$  under the FiP and CP regime. Thus, on the one hand we compute the net surplus changes of RTP and FRP consumers when changing from CP to FiP. On the other hand, we analyze the relative benefits of raising the RTP share under CP and FiP induced RES entry. Accordingly, we compute the net surplus changes between equilibria where the RTP share is raised from  $\alpha_0$  to  $\alpha_1$  with  $\alpha_1 > \alpha_0$ . Total surplus changes can then be decomposed into incumbent RTP and FRP consumer surplus changes as well as surplus gains of consumers switching from FRP to RTP.

The starting point for calculating welfare effects is overall gross consumer surplus as defined in equation (16) above. Note that it increases strictly with decreasing prices up to the point where the retail price is zero,  $p_r + l = 0$ . For lower prices however, gross consumer surplus begins to decrease. This is because the price is set for consumers who have a negative willingness-to-pay. They therefore incur “damage” from additional consumption. However, consumers are compensated for this by receiving the negative retail price during these hours (see section 3.1). This is reflected in the total net consumer surplus (welfare), which equals gross consumer surplus minus the costs of electricity given by the total payments for electricity by RTP and FRP consumers:

$$CS^{net} = CS^{gross} - \sum_t [\alpha \cdot (p_t + l) \cdot Q_t^{RTP}(p_t, l) + (1 - \alpha) \cdot (\bar{p} + l) \cdot Q_t^{FRP}(\bar{p}, l)] \quad (17)$$

The net surplus change of FRP consumers, i.e. consumers who face a flat-rate price for both values of  $\alpha$  considered, is calculated as follows as

$$\begin{aligned} \Delta CS^{FRP} &= (1 - \alpha_1) \cdot (CS_1^{FRP} - CS_0^{FRP}) \quad (18) \\ &= \sum_t (1 - \alpha_1) \cdot \left[ \left( \frac{(\bar{p}_0 + l_0)^2 - (\bar{p}_1 + l_1)^2}{2 \cdot m} \right) \right] \\ &\quad - \sum_t (1 - \alpha_1) \cdot [Q_{t,1}^{FRP} \cdot (\bar{p}_1 + l_1) - Q_{t,0}^{FRP} \cdot (\bar{p}_0 + l_0)] \end{aligned}$$

with  $Q_{t,1}^{FRP} = \frac{p_0 - (\bar{p}_1 + l_1)}{m}$  and  $Q_{t,0}^{FRP} = \frac{p_0 - (\bar{p}_0 + l_0)}{m}$ . Note that the first term reflects changes in gross consumer surplus and the second reflects changes in the costs of the electricity consumed.

The net surplus change of incumbent RTP consumers is calculated as

$$\begin{aligned} \Delta CS^{RTP} &= \alpha_0 \cdot (CS_1^{RTP} - CS_0^{RTP}) \quad (19) \\ &= \sum_t \alpha_0 \cdot \left[ \left( \frac{(p_{t,0} + l_0)^2 - (p_{t,1} + l_1)^2}{2 \cdot m} \right) \right] \\ &\quad - \sum_t \alpha_0 \cdot [Q_{t,1}^{RTP} \cdot (p_{t,1} + l_1) - Q_{t,0}^{RTP} \cdot (p_{t,0} + l_0)] \end{aligned}$$

with  $Q_{t,1}^{RTP} = \frac{p_0 - (p_{t,1} + l_1)}{m}$  and  $Q_{t,0}^{RTP} = \frac{p_0 - (p_{t,0} + l_0)}{m}$ .

Finally, the net surplus change of those consumers who switch from FRP to RTP is

$$\begin{aligned} \Delta CS^{SWITCH} &= (\alpha_1 - \alpha_0) \cdot (CS_1^{RTP} - CS_0^{FRP}) \quad (20) \\ &= \sum_t (\alpha_1 - \alpha_0) \cdot \left[ \left( \frac{(\bar{p}_0 + l_0)^2 - (p_{t,1} + l_1)^2}{2 \cdot m} \right) \right] \\ &\quad - \sum_t (\alpha_1 - \alpha_0) \cdot [Q_{t,1}^{RTP} \cdot (p_{t,1} + l_1) - Q_{t,0}^{FRP} \cdot (\bar{p}_0 + l_0)] \end{aligned}$$

with  $Q_{t,1}^{RTP} = \frac{p_0 - (p_{t,1} + l_1)}{m}$  and  $Q_{t,0}^{FRP} = \frac{p_0 - (\bar{p}_0 + l_0)}{m}$ . As can be verified, the sum of all surplus changes for the different consumer groups equals the overall change in (net) consumer surplus.

### 3. RESULTS

#### 3.1 Effects on prices, quantities and welfare

Before presenting and discussing results, it is helpful to illustrate and disentangle the distortionary effects on consumer surplus of both instruments. Figure 1 shows these effects for the FiP, while Figure 2 shows them for the CP—for representative hours of high RES supply ( $RE+$ ) and low RES supply ( $RE-$ ). We decompose the total welfare effect into three parts, which we also refer to when discussing results in this and the following sections. The first effect holds for both instruments: due to the additional levy  $l$  on top of wholesale prices  $p_t$ , the retail price  $R_t = p_t + l$  is

Figure 1: Effects of FiP on consumer surplus.

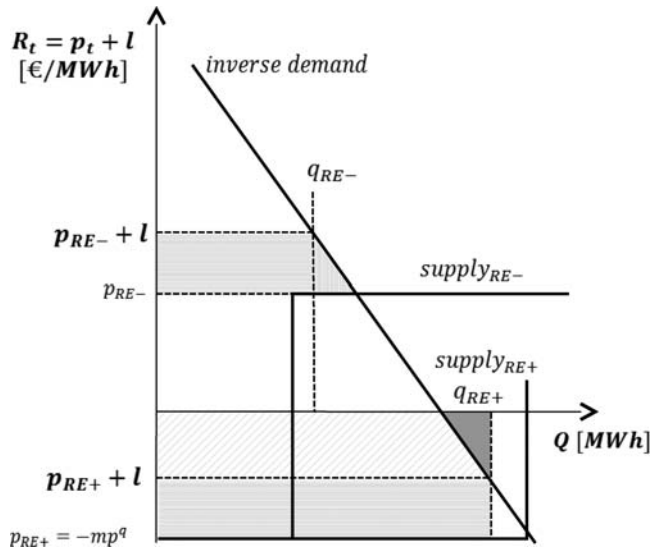
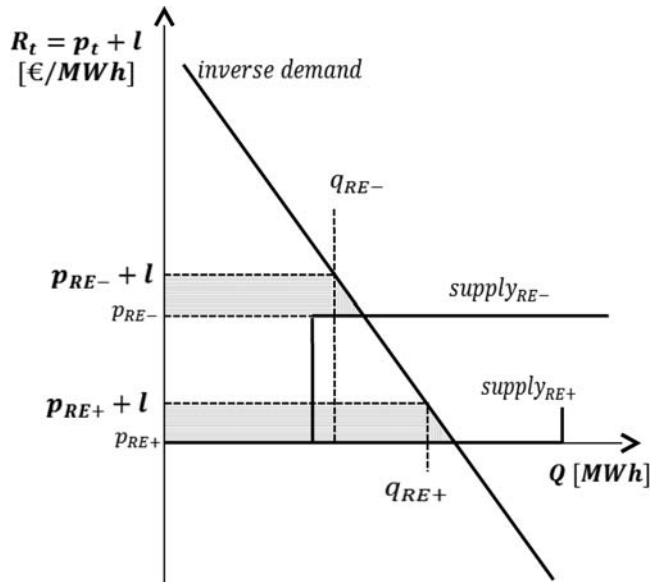
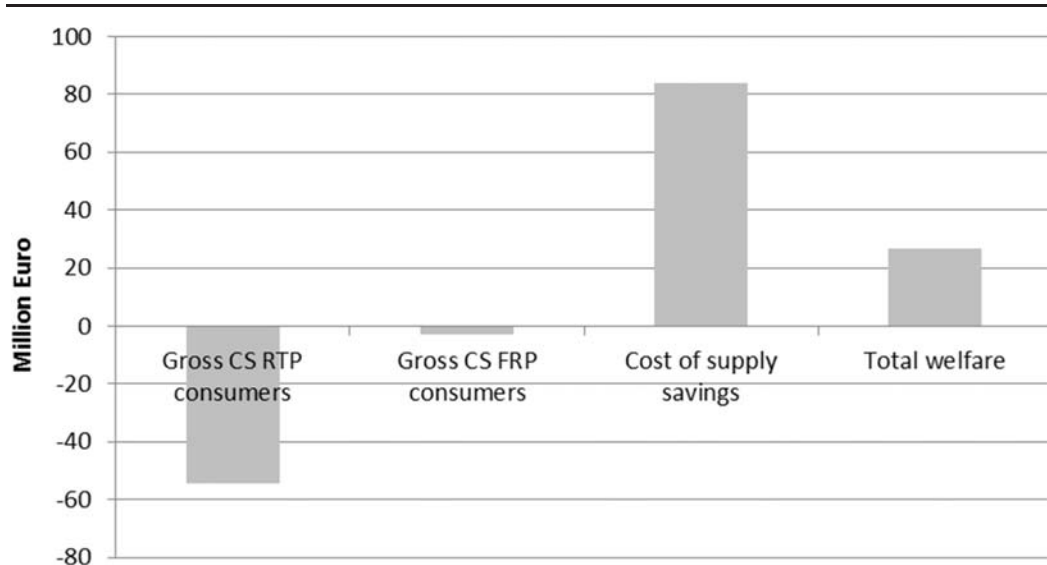


Figure 2: Effects of CP on consumer surplus.



increased, which in turn reduces consumption and respective net consumer surplus. This reduction comprises a dead weight loss (vertical hatched area), and the overall levy payments to RES generators (horizontal hatched area).

The second effect is increased net consumer surplus under the FiP in times of high RES supply. More precisely, in contrast to the CP, the FiP induces a downshift of the supply curve to the negative value of the premium ( $-mp^q$ ). Since the levy is always lower than the premium, this means higher RES utilization and consumption. Given that consumers are saturated when  $R_t$  equals

**Figure 3: Decomposed net consumer surplus (welfare) differences if changing from CP to FiP, in € million/year.**

zero, they have a negative willingness-to-pay beyond this point and thus incur “damage”. In turn, gross consumer surplus is reduced (solid grey triangle). However, consumers are paid the (negative) wholesale price, net of the levy, multiplied by their consumption, such that there is an overall gain in net consumer surplus (diagonal hatched area). Importantly, the overall size of these effects depends on the proportion of RTP consumers, because FRP consumers only respond to average annual prices and cannot increase consumption in periods of low prices. A third effect, not directly shown in either figure, is that less capacity is required under the FiP to meet the renewable production target. This is because renewable capacities are utilized to a greater extent under the FiP since consumption in high RES supply hours ( $RE+$ ) is higher compared to the CP due to the negative wholesale prices under the FiP. The higher utilization of RES under the FiP therefore implies that less RES capacities are needed to meet the renewable production target.

These effects have important implications for the value of RES capacities and respective costs. Under the FiP, RES produce also at negative prices so their market value will be lower compared to the CP. In turn, in order for renewables to cover their fixed costs, total subsidies need to be higher, and thus the levy under the FiP will also be higher than under the CP. This may at first glance imply that the FiP is less efficient, since consumers have to pay a higher levy to subsidize RES, which additionally distorts consumption.

Figure 3 shows the differences between FiP and CP for all relevant welfare terms as described in section 2.2.3 for the base case, i.e. a price elasticity of  $-0.05$  and a 10% share of RTP consumers. Results confirm that gross consumer surplus is indeed lower under the FiP. In particular, RTP consumers are worse off, because their respective price distortion is greater than under the CP. More specifically, RTP consumers under the FiP lose gross consumer rents in periods with negative prices due to additional damaging consumption (second effect, see above)—and they lose even more in all other periods because the levy is higher than in case of the CP (first effect). Yet total welfare is higher under the FiP. This stems from lower total costs of supply due to decreased capacity entry (third effect). In other words, the benefits of gross consumer surplus of the CP are outweighed

Figure 4: Equilibrium capacities under CP.

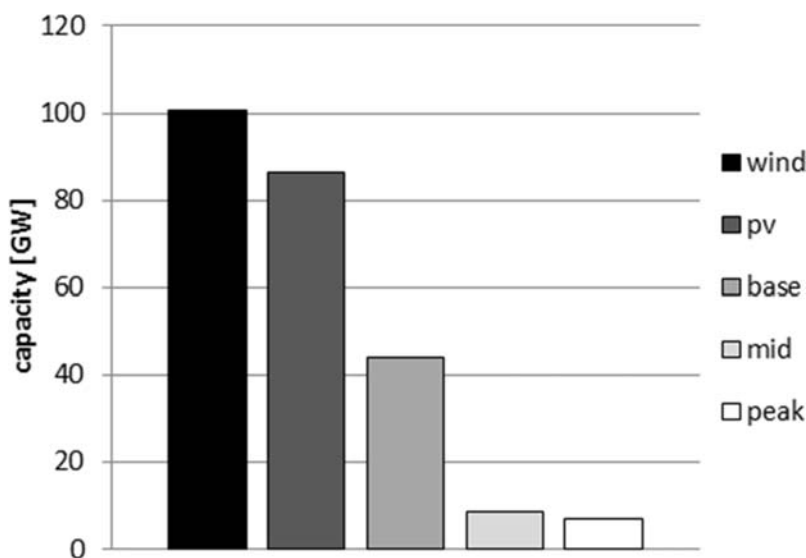
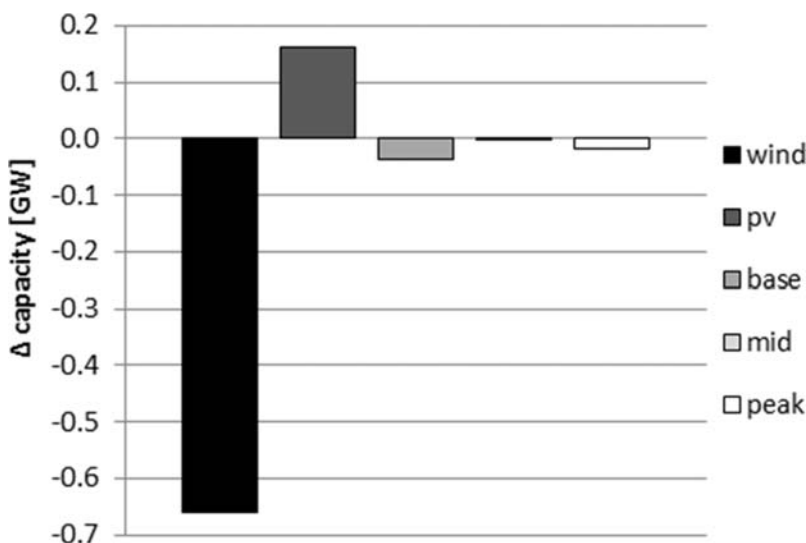


Figure 5: Capacity difference under FiP compared to CP.



by RES capacity cost advantages under the FiP. Finally, relating welfare differences to industry turnover shows that differences are only around 0.1%, and thus very small, at least for the base case we consider. Yet in this context, the size of the effect is less important than its direction. We also demonstrate below that it substantially increases for higher RES shares.

As Figure 4 and Figure 5 show in more detail, capacity differences are largest for wind, where 0.66 GW less capacity is built. Fossil capacities are also somewhat lower, but the effect is considerably smaller. This is because fossil plants do not produce when wholesale prices are negative, and are thus only affected through the change in the RES portfolio and the differences in

**Table 3: Comparison of prices and market values.**

	RTP wholesale price* [€/MWh]	FRP wholesale price [€/MWh]	Levy [€/MWh]	RTP retail price [€/MWh]	FRP retail price [€/MWh]	Turnover [€bil.]
FiP	27.5	37.2	43.1	70.6	80.3	34.7
CP	40.9	48.1	32.1	73.0	80.2	34.8

\*demand-weighted average

consumption levels, which are lower under the FiP during times with positive retail prices due to the higher levy (first effect). Note that this also counteracts the effect of increased consumption during negative price hours under the FiP. Therefore, total consumption over the year is quite similar under the FiP and CP. In contrast, solar PV capacity is around 0.16 GW higher, which can be traced back to its specific availability pattern (increased generation during times of high demand).

When looking at prices as shown in Table 3, considerable differences come up. The average RTP wholesale price in case of the FiP is much lower ( $\sim 28$  €/MWh) than that of the CP ( $\sim 41$  €/MWh). As explained above this is because the premium on energy creates incentives to produce, even at negative prices. This happens in nearly 1200 hours and consequently lowers the average price<sup>6</sup>. This of course also affects the market value of RES technologies, which are likewise considerably lower under the FiP: 7.4 €/MWh compared to 29.5 €/MWh for wind, and 4.4 €/MWh compared to 27.0 €/MWh for solar PV. Likewise, overall support payments are also higher for the FiP than the CP (€18.8bn compared to €14.0bn). This is also reflected in higher levies paid by consumers (43.1 €/MWh vs. 32.1 €/MWh).

Importantly, while instruments differ considerably with respect to the wholesale price and levy levels they induce, overall retail prices are relatively similar. In particular, FRP consumers (90% of all consumers) face nearly identical prices, while there is a slight difference for RTP consumers (remaining 10% of consumers) due to the induced negative prices.

### 3.2 Welfare and distributional effects of increasing real-time pricing

In this section we look at welfare and distributional effects from changing the RES support scheme, for both a given and a rising share of RTP consumers ( $\alpha$ ). Table 4 shows the gross (left columns) and net (right columns) consumer surplus differences from changing from the CP to the FiP regime for *given* RTP shares. Regarding the net consumer surplus changes, FRP consumers are worse off under the FiP than under the CP (negative values), while RTP consumers are generally better off and their benefits outweigh FRP consumers' losses so that overall welfare (net consumer surplus for all consumers) increases.

Furthermore, FRP consumers lose when changing from CP to FiP because their final retail price  $\bar{p} + l$  increases. More specifically, the wholesale price  $\bar{p}$  becomes smaller, but the levy  $l$  rises relatively stronger, as shown in Table 3. This is mainly due to the negative wholesale prices as explained in the previous section. Additionally, by raising consumption in negative price hours in comparison to the CP, RTP consumers exert both a positive and a negative pecuniary externality affecting the levy and thus FRP consumers: the positive externality reduces the levy since less RES

6. We assume there is always sufficient demand response such that there is no administrative curtailment. This further implies that we assume that value of lost load (VoLL), which theoretically should define the price cap, is above 1449 €/MWh since this is the maximum wholesale price under both instruments in our model.

**Table 4: Consumer surplus changes if changing from CP to FiP, in € million/year.**

$\alpha$	FRP consumers		RTP consumers		All consumers	
	Gross	Net	Gross	Net	Gross	Net
1%	-0.4	-3.3	-5.7	6.0	-6.1	2.8
10%*	-3.1	-27.6	-54.3	54.2	-57.4	26.6
20%	-5.2	-46.1	-103.1	96.7	-108.3	50.6
30%	-6.3	-56.2	-146.3	128.6	-152.6	72.4
40%	-6.5	-58.5	-181.9	150.1	-188.5	91.6
50%	-6.2	-55.0	-210.5	163.4	-216.7	108.4

\*base case

entry is needed to meet the RES production target (third effect, see section 3.1). On the other side, the negative externality increases the levy through relatively higher consumption of RES in negative price hours by RTP consumers. This negative externality outweighs the positive externality, which mainly explains why all in all the levy increases more than the flat energy prices for FRP consumers falls when changing from the CP to FiP. In contrast to RTP consumers, they cannot profit from raising their consumption during periods where RTP consumers are paid to do so. Instead, FRP consumers finance the remuneration of RTP consumption in these hours.

Table 4 further shows that RTP consumers also incur gross surplus losses from, firstly, paying a higher levy under the FiP which implies a higher dead weight loss (first effect, see section 3.1) and, secondly, from incurring a “damage” of consuming above their saturation level (second effect, see section 3.1). However, in contrast to the FRP consumers they overall net benefit mainly because of the payments they receive per unit of consumption when wholesale prices are negative. Put differently, they benefit from implicit cross-subsidies paid by FRP consumers for their consumption during these hours as explained in the previous paragraph.

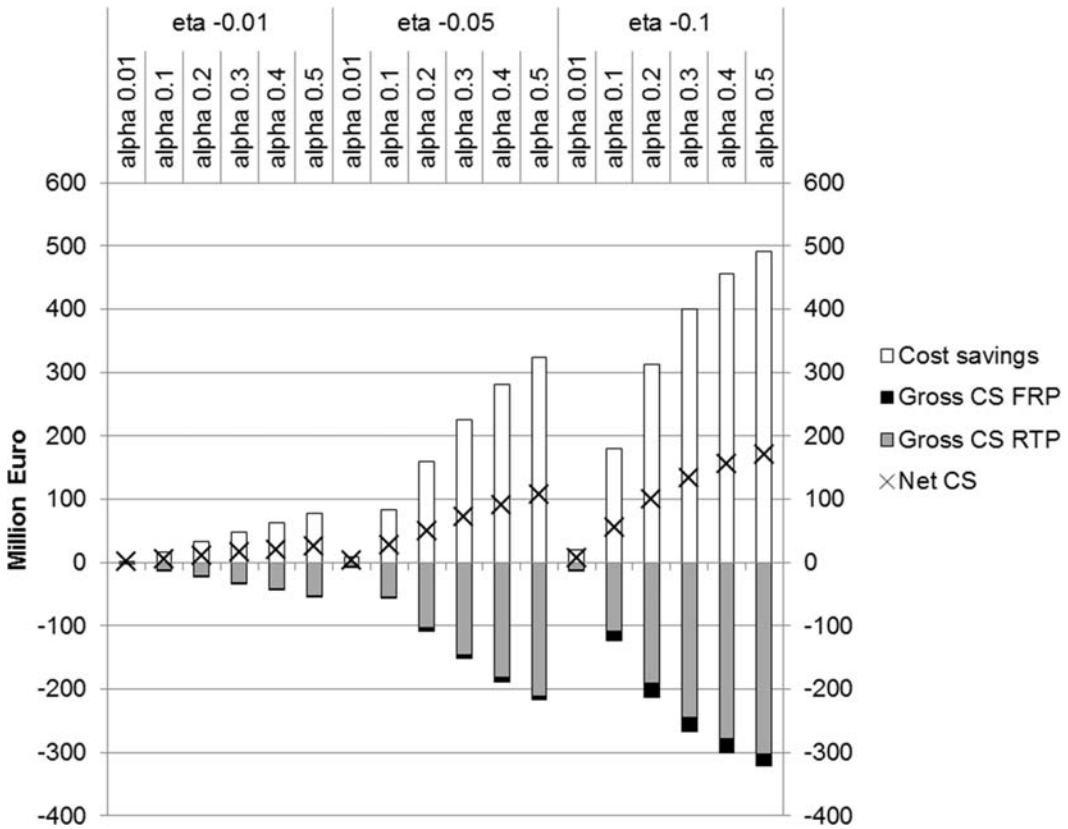
Moreover, following the intuition given in section 3.1, the third column in Table 4 shows that total welfare gains from changing to the FiP increase with the given RTP share  $\alpha$ . The larger the portion of consumers able to respond to the real-time retail price  $p_t + l$ , the relatively higher is the utilization of installed RES capacity at negative prices and thus relatively less RES capacity to achieve the RES production target is required (third effect, see section 3.1). The differences in total gross and net surplus (“All consumers”) show the cost of supply savings which, as described, explain why the FiP leads to a higher welfare level than the CP.

As can be taken from comparing the total welfare gains for different RTP shares, the incremental cost savings or welfare gains respectively decrease with the RTP share  $\alpha$  (see also Figure 6). This is mainly because the higher the share of RTP consumers, the higher is the RES capacity utilization already under the CP, so that it can only be increased to a lower extent when changing to the FiP. Therefore, also the effect of lower RES capacity entry and thus the cost of supply savings under the FiP decrease with the RTP share. On the other hand, lower relative changes in welfare gains from changing to the FiP hint towards lower relative retail price distortions induced by the levy, which are mitigated via a higher RTP share  $\alpha$ . This is intuitive since higher RTP shares mitigate allocative inefficiencies. In fact, the difference between the levy under the CP and FiP decreases with the RTP share (not shown), while the levy shrinks under both the CP and the FiP when  $\alpha$  rises.

Furthermore, efficiency gains from raising the RTP share decrease with higher  $\alpha$  (Borenstein and Holland, 2005). This can be seen by comparing the total net consumer surplus changes



**Figure 6: Decomposed net consumer surplus (welfare) differences if changing from CP to FiP for different elasticities and RTP shares, in € million/year.**



$\Delta CS^{SUM}$  from raising the RTP share under either CP or FiP in Table 5. Moreover, Table 5 shows that by and large incumbent RTP consumers ( $\Delta CS^{RTP}$ ) lose<sup>7</sup> while FRP consumers ( $\Delta CS^{FRP}$ ) generally benefit from a higher RTP share for the reasons explained above. The relatively higher net surplus gains of consumers switching to RTP  $\Delta CS^{SWITCH}$  under the FiP reflect the larger inefficiency from hourly flat consumption, which stems from the larger price distortion and the larger variance in wholesale prices due to the occurrence of negative prices driven by the output subsidy  $mp^q$ . That is, FRP consumers over- and under-consume relatively more under the FiP, particularly during negative price hours, implying higher allocative inefficiency. This implies higher gains from mitigating the latter via raising consumers' ability to consume optimally by putting more consumers

7. Note that while this always holds in Borenstein and Holland (2005), it is not necessarily the case in our model. Surplus gains of incumbent RTP consumers become positive when the RTP share is increased from 40% to 50% under the CP since the levy drops more than the off-peak price hours rise after the RTP share is raised: an increase of RTP implies that the utilization of RES increases since more RTP consumers increase their consumption during abundant RES supply hours. As explained above, less RES capacity entry is thus needed to achieve the RES production share target implying that the levy to finance RES capacities can be lower. While the decrease itself is relatively small (0.14 €/MWh), when multiplied with the total consumption of RTP consumers (176 TWh) it results in overall surplus gains of around €25 million.

**Table 5: Net consumer surplus changes between different RTP shares, in € million/year.**

$\Delta\alpha$	$\Delta CS^{FRP}$	$\Delta CS^{RTP}$	$\Delta CS^{SWITCH}$	Total
<i>Market premium on energy (FiP)</i>				
10% → 20%	39.0	−29.5	184.6	194.1
20% → 30%	28.3	−24.7	167.4	171.0
30% → 40%	23.5	−21.8	156.0	157.7
40% → 50%	19.8	−19.4	147.3	147.7
<i>Market premium on capacity (CP)</i>				
10% → 20%	60.5	−23.6	133.2	170.1
20% → 30%	44.2	−13.7	118.7	149.1
30% → 40%	33.9	−5.8	110.5	138.6
40% → 50%	26.2	0.4	104.9	131.5

on RTP. Put differently, switching becomes more beneficial under FiP mostly because consumers then get paid for consuming electricity during negative price hours.

Hence, consumers may in general be more willing to switch to RTP under the FiP and thereby partially offset the welfare losses from relatively larger price distortions. Likewise, any efforts to increase RTP shares, be it infrastructure investments or institutional adjustments, are more rewarding under the FiP. But a significant part of the additional switching incentives under the FiP comes from implicit cross-subsidies during negative price hours paid by FRP consumers. That is, changing from a CP to a FiP also has important distributional consequences.

### 3.3 Sensitivity analyses

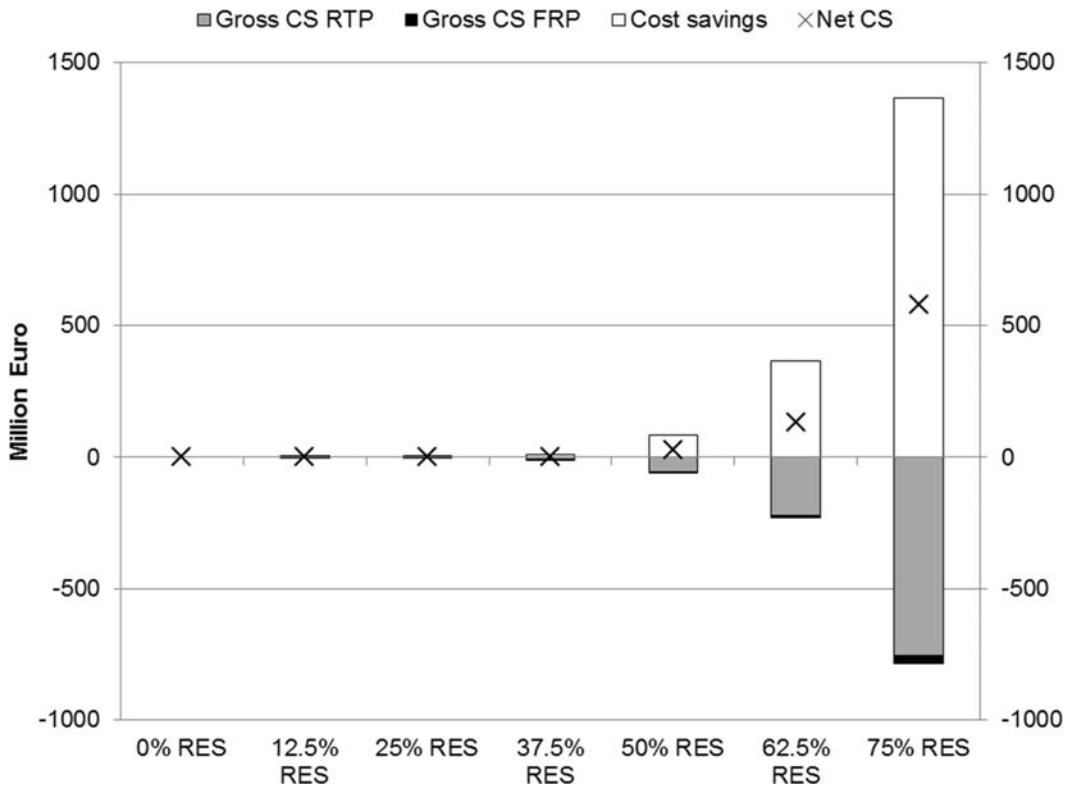
In order to test the robustness of the base case findings, we investigate the effects of alternative assumptions. On the one hand, we consider alternative price elasticities of demand, i.e.  $-0.01$  and  $-0.1$  instead of  $-0.05$ . On the other hand, we look at alternative RES shares, ranging from 0% to 75%.

Figure 6 summarizes the effects of different price elasticities, under varying RTP shares, on gross consumer surplus of RTP and FRP consumers, costs of supply, and resulting net consumer surplus. It can be seen that qualitative results do not change compared to the base case. Yet absolute differences between respective CP and FiP settings grow with increasing demand flexibility as explained in the previous section.

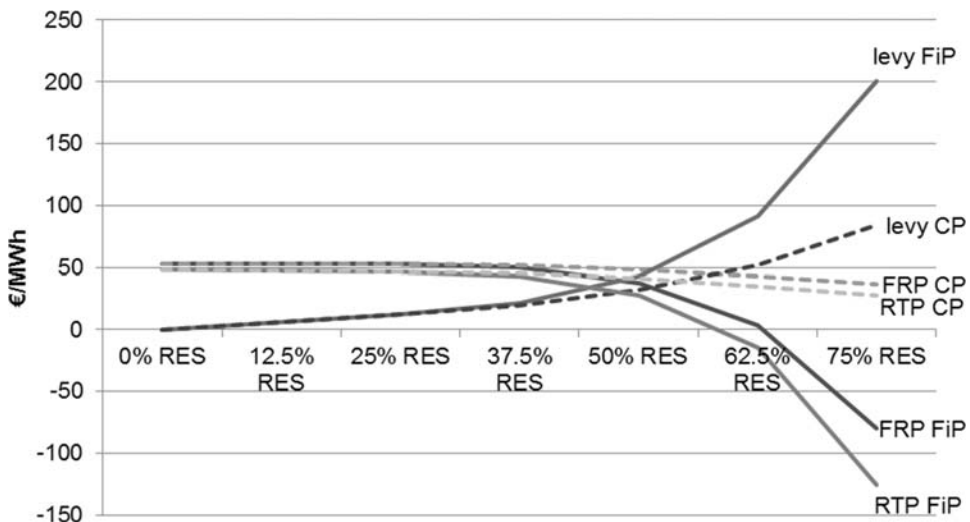
Figure 7 shows welfare differences between the two instruments for varying RES shares. For shares lower than 50%, there is hardly any difference between the FiP and the CP, as renewable surplus generation, and in turn negative prices, hardly play a role. Yet for RES shares beyond 50%, renewable surpluses become much more frequent, such that the relative advantage of the FiP increases substantially to around €7.6 billion in the 75% case.

Figure 8 shows energy price and levy levels for RTP and FRP consumers for different RES shares. A general observation is that wholesale prices decrease with increasing RES shares, while levies increase. This is because with rising shares RES become price-setting in increasingly many hours, which in turn reduces average wholesale prices and thus RES technologies' market value. Consequently, market premiums have to be relatively higher to compensate this effect, and at the same time more RES capacities receive the premium such that the levies also need to rise accordingly. While effects are moderate under both the CP and FiP up to a share of around 50%,

**Figure 7: Decomposed net consumer surplus (welfare) differences if changing from CP to FiP for different RES shares, in € million/year.**



**Figure 8: Demand-weighted real-time wholesale prices (RTP), flat-rate wholesale prices (FRP) and levies for varying RES shares under FiP and CP.**



there are large deviations for higher shares. Very high RES targets drive a large wedge between energy prices and levies, particularly for the FiP due to the negative wholesale prices. In the 75% case, both the average RTP and FRP energy price become negative under the FiP and the levy rises to more than 200 €/MWh.

#### **4. DISCUSSION OF LIMITATIONS**

In this section, we briefly discuss some limitations of the model and indicate the direction in which these limitations may distort results.

While focusing on increased RTP, we neglect other flexibility options such as dispatchable renewable electricity sources, electricity storage, and international trade. In particular, storage and international trade will cause demand to increase in times of high RES generation and low prices, while these options increase supply in times of high residual demand. We thus tend to overestimate the fluctuations of residual load and spot prices, and the occurrence of negative prices. We accordingly also overestimate the value of increased demand-side flexibility.

A similar reasoning applies to the scaling up of historic renewable feed-in time-series. While this method is often applied in the literature, it disregards potential future smoothing effects related to changes in the design and the spatial distribution of renewable generators (see Schill 2014). This may also contribute to an overestimation of the negative prices and the value of RTP.

The opposite is true for other limitations of the model, i.e. disregarding costs and flexibility restrictions of thermal generators such as start-up and ramping costs, or restrictions related to combined heat and power generation. Ignoring such constraints substantially decreases the model's computational burden. This appears to be at least partly justified as we take a long-term perspective for which it can be assumed that the flexibility of thermal generators will not become a major issue because of technological improvements and changes in the generation portfolio; compare also Schill et al. (forthcoming). We do however acknowledge that results may be distorted because of this simplification. If such flexibility restrictions were considered in the model, negative prices under the FiP may occur even more often. At the same time, ramping-related costs of base-load plants could be higher under the FiP. Determining the net effect on welfare outcomes would require a dedicated analysis.

As for additional sensitivity analyses, it may be worthwhile assessing the robustness of welfare effects not only with respect to different elasticities, RTP shares and RES targets, but also for different functional forms of demand. For example, the general findings should also hold under an iso-elastic demand function, which would allow for negative wholesale (but not retail) prices. Overall effects may be even larger compared to the linear demand function considered here because of a greater increase in consumption during periods of negative prices. Investigating these effects is left for future research.

Our rather stylized approach of modeling electricity demand also requires discussion. Firstly, RTP not only incorporates hourly increase and reduction of demand, but also demand that shifts over hours. In engineering-oriented dispatch models with price-inelastic demand, such shifts can, in principle, be modeled by using appropriate constraints; see Zerrahn and Schill (2015). Yet in economic models with price-elastic demand, a proper representation of load shifts is more challenging (De Jonghe et al., 2014). The relevant behavioral parameter is cross-price elasticity, which is typically measured between peak, off-peak and sometimes also shoulder periods; see Faruqui and Sergici (2010) for a review of studies. However, prices in a market with high RES shares no longer exhibit such typical price patterns. Parameterizing cross-price elasticity in a future setting with high shares of RES would thus be highly speculative.

Finally, it is not clear whether actual consumers are truly as responsive to price changes as typically assumed in economic models. In particular it is doubtful whether lower prices lead to steadily increasing consumption levels. In fact, most research so far, such as Wolak (2011), focuses on RTP in times of peak prices (price spikes). Recent research by Lang and Okwelum (2015) on off-peak behavioral responses, however, confirms that consumption indeed increases in off-peak times because load is being shifted, at least partly, from peak times. Likewise, it is questionable whether the value of making consumers more responsive to real-time prices always compares favorably with the costs of equipping them to do so. Léautier (2014) for example argues that in the case of small residential customers this value might be far below the cost of installing smart meters.

## 5. DISCUSSION AND CONCLUSIONS

In this paper we analyze welfare effects of RES support instruments, focusing on the nexus of price responsive demand, negative electricity prices and relative RES targets in total electricity production. More specifically, we compare the total annual welfare obtained under two support instruments to achieve a RES production target: a production subsidy (FiP) which can induce negative wholesale energy prices and a capacity subsidy (CP) which does not. Since it implies stronger deviations from marginal cost pricing, common intuition suggests that the presence of negative prices lowers the relative efficiency of reaching a certain RES target, so that a CP may appear to be the more cost-efficient instrument.

Contrary to this intuition, we find that a FiP can actually lead to higher welfare than a CP despite greater wholesale price distortions. This is because a RES production target can be achieved at lower overall costs, since less RES capacity is required to obtain a given share in total production. More precisely, negative prices during hours of high RES supply incentivize RTP consumers to raise their consumption more than under the CP regime, where retail prices never drop to or below zero. Thus, RES capacities are utilized to a relatively larger extent than under the CP, implying that the same RES production target is achieved with less RES capacity entry. This finding hinges on two main assumptions: (i) a relative renewable target defined as a share in production, and (ii) a positive proportion of consumers who face real-time prices. As said above, the former allows for the capacity required to achieve the target to vary, depending on the overall level of demand and the amount of renewable output that can be sold to the market. This assumption is also of practical relevance due to the widespread implementation of production targets.

When determining welfare we do not explicitly consider the social benefits of renewable production. For a full welfare perspective though, an explicit rationale for RES subsidies (e.g. learning spillovers) would need to be included in the analysis, which we ignore for the sake of concentrating on the isolated performance in achieving a given target. There is however other literature that addresses this question. For example, if learning spillovers would indeed be the main rationale, it can be argued that the efficient subsidy is a capacity payment though (Newbery, 2012). Also Andor and Voss (2016) argue that capacity subsidies are the appropriate mean to address externalities arising from learning spillovers—but if the rationale would be to reduce GHG emissions (second best) then a subsidy on production would be justified. Accordingly, there is a rationale for both instruments, and we leave it up to the reader to decide which one is more convincing.

Another important result relates to the effect of increasing the share of RTP consumers. In particular for the FiP and its relatively stronger distortionary effect on prices, higher RTP shares mitigate respective welfare losses due to allocative inefficiencies arising from over- and under-consumption given a fixed retail price. Moreover, broken down to consumer groups, surplus gains are markedly higher for consumers who switch from FRP to RTP under the FiP. This has important

implications: On the one hand, assuming that these surplus gains will be fully internalized by the respective consumers, there are accordingly higher incentives for consumers to switch under the FiP. On the other hand, also the distributional effects need to be considered. A significant part of the additional RTP consumer surplus under the FiP is implicitly financed by the FRP consumers. That is, FRP consumers cross-subsidize RTP consumption in negative price hours, since only the latter get paid for increasing consumption during these periods. This could represent a significant social acceptance barrier to introducing RTP under a FiP. Furthermore, surplus gains roughly double when demand is assumed to be twice as elastic at the reference point. This underlines that the preferences and technological capabilities to respond to prices also play a very important role.

What definitely merits further discussion is that as prices become negative under the FiP, excessively using electricity in low-price periods appears to be a viable business model that becomes increasingly attractive with higher RES shares. In fact, in hours with negative prices energy consumption is indeed excessive in the sense that consumers receive disutility from it—and the good becomes a bad from a consumer perspective. At the same time, in such hours RES energy supply is abundant and all electricity consumed comes from RES. Since the RES production target implies that each unit of RES output has an additional social value ( $\lambda^r$ ), the private disutility per unit of excess consumption stands in a trade-off with this social value. Accordingly, while energy is wasted from a private perspective, it is put to good use from a social perspective because the implied higher per-unit production (higher capacity factors) reduces the required RES capacity and thereby the overall costs of energy supply. Further, as our findings show the net social benefits over the whole year are positive. Hence the above paradoxical situation is put into perspective when the social value of RES supply and the capacity reducing effect are taken into account.

Notwithstanding this effect, negative prices warrant caution because they could have further implications beyond the scope of this work, which may be of high practical importance. For example, we do not explicitly consider cross-price elastic behavior (load shifting), and we ignore endogenous investments to exploit negative prices. In practice though, RTP consumers might indeed exploit negative prices by investing in smart appliances, and it is unclear if this would increase their inclination for consumption in other hours as well. Thus, the structural consumption pattern could change substantially and differ rather strongly from the one we assumed. Moreover, empirical evidence for price elastic behavior at times of low or negative prices is so far rather poor, and actual effects might well deviate from our results in either direction.

In summary, this work first of all provides additional theoretical insights concerning RES support schemes and induced negative prices that have been overlooked in the literature. As for policy recommendations, the scope and limitations of our work defy a clear cut ranking of one instrument over the other. Rather we think that the primary practical added value of this work is to confront policy-makers with the widely held view that negative prices are in general inefficient. We hope that this makes them more considerate of their potential benefits and respective policy options.

## **ACKNOWLEDGMENTS**

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