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PROFITABILITY OF POWER GENERATION AND ENERGY STORAGE IN LOW-CARBON ELECTRICITY MARKETS: A FUNDAMENTAL ANALYSIS

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Profitability of Power Generation and Energy Storage in Low-Carbon Electricity Markets: A Fundamental Analysis

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Abstract

This paper analyses how the profitability of power generation and energy storage are affected by the introduction of competitive variable renewable energy (VRE) sources in electricity markets. We give an overview of renewable integration challenges in current markets, and how different flexibility sources, market mechanisms and other actions can facilitate efficient operation and planning of systems with very high renewable shares. We show, by using an analytical approach, how all technologies recover their costs in system optimum, and maximize their profits in perfect energy-only markets with a resource mix consisting of thermal generation, VRE and energy storage. Moreover, we derive the equilibrium conditions for electricity markets with additional capacity requirements and corresponding capacity payments. Our analysis indicates that the marginal unit of capacity is highly influenced by the capacity constraint, whereas there is limited impact on the profitability of base load power plants if proper capacity payments are provided. There is also limited impact on VRE capacity. Moreover, for VRE dominated systems, resource adequacy should be reconsidered considering contributions from demand resources in addition to energy storage and generation technologies.

Keywords: electricity markets, market equilibrium, variable renewable energy

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I. INTRODUCTION

Many techno-economic studies have proven that a power generation mix with very low GHG emissions is technically feasible and cost-effective, see e.g. [1]. This is promising news, since electrifying other energy sectors to decarbonize the energy mix is one of the main steps on the way towards the required reduction of global CO2-equivalent emissions by 2050 [2]. As the power generation changes from thermal-based to renewable-based, new issues arise with regards to power system operation, including balancing and stability [3]. Also, the long-term profitability of different power plants and energy storage assets will be challenged [4][5][6]. On the way towards the goals of full decarbonisation in 2050, these low-carbon power systems will involve a growing number of different players: traditional power generation companies, independent power producers, demand aggregators and storage operators. Unless each of these players receives an adequate revenue corresponding to its contribution to the power system, the decarbonization of the power system may well be achieved in a suboptimal way. Moreover, if the required flexible resources fail to remain profitable and online, the current level of reliability will no longer be feasible, or full decarbonization will not be possible.

This paper presents an economic analysis of investments and profitability in market-based low- and zero-carbon power systems. We derive optimality conditions for the planning and operation of key energy technologies (renewable power plants, energy storage, and thermal generation) based on the fundamental market modeling approach presented in our previous work [4]. This method is based on stylized net load duration curves, which enables us to derive solutions for cost-optimality of all main technologies and corresponding long-run equilibrium in competitive markets. Using the analytical approach, we show how an optimal resource mix can be compatible with profitability for each player under different electricity market designs (energy-only, capacity market), under certain conditions. Moreover, we present numerical examples that highlight which technology and market design parameters are key to long-term investment and profitability in a future decarbonized power system.

The rest of the paper is organized as follows: Chapter II gives an overview of challenges that actors in the power markets face when renewable energy sources and energy storage become more competitive. Chapter III presents foundations for profitability and cost-recovery in energy-only power markets based on the theoretical framework given in [4]. In Chapter IV, we expand the fundamental models to incorporate capacity requirements, and analyse how corresponding capacity payments impact cost recovery of all technologies in the system. Chapter V concludes the paper with insights from the analytical results and numerical case studies and give directions for further fundamental market analyses.

II. MARKET CHALLENGES RELATED TO VRE

With the transition towards low-carbon power systems, electricity market design will have to adopt to a changing resource mix that is likely to have very high shares of wind and solar energy and low shares of conventional dispatchable generation. To address the variability and uncertainty in variable renewable energy (VRE) resources, markets must incentivize flexibility across different timescales, also from distributed resources like demand side response, as well as enable smart energy sector coupling. Key market challenges include [5][7][8][9]:

1. Incentivizing sufficient generation investments to meet reliability standards, as the so-called missing money problem may be exacerbated by the merit-order effect from VRE with low or zero marginal costs
2. Incentivizing flexibility for short term balancing (for example larger ramps like the pronounced evening ramp from the 'duck curve' seen with higher shares of solar PV) and long term for helping resource adequacy and resiliency, easing the need for costly back up capacity. This means, for example, ensuring that energy storage resources receive compensation commensurate with the range of services they provide to the power system
3. Introducing new products in markets for essential reliability services (also called ancillary services), for managing power system operations in a cost-effective manner with increasing amounts of inverter-based resources, including VRE and electric energy storage (EES)
4. Integrating different markets geographically to benefit from larger market areas; coordination of emerging local flexibility markets with wholesale markets (transmission-distribution system coordination, to capture full value of distributed flexibility resources); and electricity market couplings with heat, gas and other potential markets associated with sector coupling
5. Aligning carbon policy mechanisms in support of VRE and other low-carbon resources with competitive electricity markets, e.g. through the design of effective carbon emission markets or the introduction of a carbon tax
6. Enabling adequate expansion of transmission and distribution systems to enable larger market areas and to take advantage of geographically dispersed VRE resources, oftentimes far away from major load centers
7. Aggregating large number of resources at the distribution side, enabling smaller distributed energy assets to be integrated in both the energy and ancillary services markets

Traditionally, the revenues of power plants and energy storage assets come largely from selling energy to the wholesale market. In future VRE dominated power systems, energy revenues may increasingly be complemented with selling essential reliability services. A key question in electricity market design is: can short-term markets for energy, flexibility, and ancillary services provide sufficient revenues to cover the full costs of grid resources, or is it necessary with additional capacity remuneration mechanisms to pay explicitly for capacity as well?

The merit order effect, i.e. decreasing spot market prices in times of large supply of low marginal cost VRE generation moving the merit order curve of supply – is already seen in many markets. This effect influences the profitability of most generators, but hits wind and solar generation the most if exposed to spot prices, as they tend to be available exactly when the prices are low [10]. Flexible thermal generators may be able to cover their costs during fewer hours if the spot prices are allowed to rise to higher levels in times when there is not much low marginal cost generation available - and no overcapacity is present. Although the merit-order effect has been observed in current electricity markets, there are several questions around how these markets will evolve in the long run, and to what extent new market equilibria will be reached which allow for competitive resources to break even.

An example of the merit order effect impacting wind power in the Nordic countries is seen in Figure 1. Although system wide Nordic wind power would not significantly experience this impact yet, the prices in different price areas often diverge, and a reduction in the market value of wind energy (income to wind energy in €/MWh relative to average spot price in €/MWh) is observed. The impact is generally increasing with increasing share of wind, however, the effect varies between years and price areas. Although the price area differences are not shown in the figure due, it is relevant to mention that the North Sweden price areas have a lot of flexibility from large hydro power with reservoirs, and the market value of wind there is better than in other Nordic price areas. Year 2020 was extreme as the pandemic reduced the demand and wind resource was better than average, also the spot price was very low (<30 €/MWh in all areas).

The merit-order effect has also been observed in electricity markets in the United States, although the downward trend in electricity prices in the last decade can largely be explained by lower natural gas prices [11]. Estimated prices emerging from various VRE integration studies of future systems typically see lower electricity prices with higher VRE penetration levels, as illustrated in Figure 2, although the generation portfolios in these studies do not necessarily reflect economic market equilibrium.

Future electricity markets should see the impact of new electrification demand helping the problem of declining market values, if the new loads have flexibility to utilize the surplus energy in situations where the prices otherwise would be pressed towards zero.

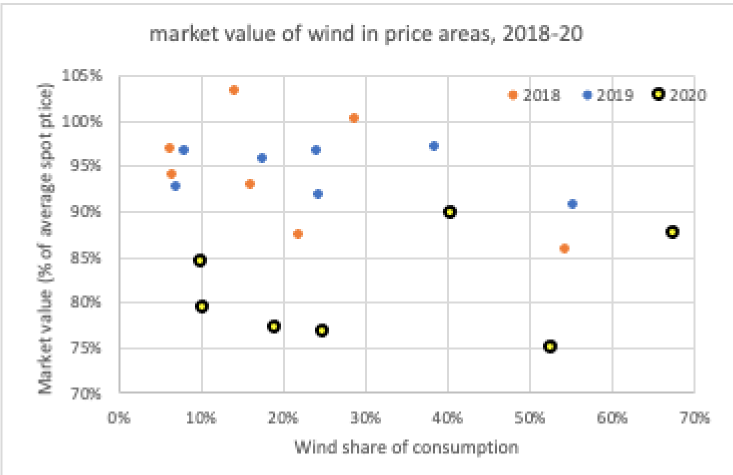

Figure 1. Wind energy income from spot (day-ahead) markets relative to average spot price in Nordpool for the Nordic price areas: Finland (FI), West-Denmark (DK1), East-Denmark (DK2), North Sweden (SE2, SE2) and South Sweden (SE3, SE4). (Source data from Nordpool, energia.fi, NVE and SvK).

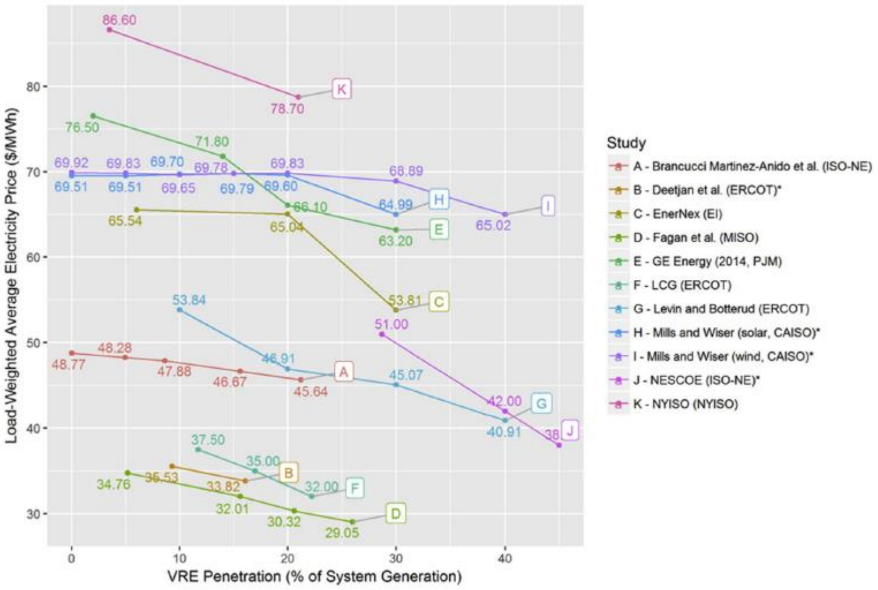

Figure 2. Projected electricity prices from selected U.S. studies of future electricity markets. From Mills et al. 2020 [11].

III. FUNDAMENTALS OF ENERGY-ONLY MARKETS WITH VRE AND STORAGE

In the previous section, some examples on how wind power influences current markets were given. With the introduction of wind and solar power in the market, the cost recovery of all generators is challenged, mainly due to the merit-order effect. Development of VRE technologies have historically been driven by subsidy schemes which have reduced their own exposure to market prices to a minimum, especially in the cases of feed-in tariffs. If VRE capacity is determined outside the market, the effect of VRE on other generators can then be analyzed by replacing demand time-series with the net demand, where the VRE generation is given from a specified VRE capacity scenario. However, as the costs for wind and solar are continuing to fall it is reasonable to believe that they can compete with other generator technologies on equal terms in more and more markets. Adding to this is the expected increase in prices for emission allowances, as already observed in the Europe ETS market, which in turns should lead to an increase the cost of fuel generation.

This development calls for more in-depth studies on how wind and solar influence the market in a fully competitive environment, without subsidies or other out-of-market arrangements for investment support, feed-in tariffs and so on. This chapter provides an analytical approach to the problem of assessing the equilibrium in energy-only markets with competitive VRE. The full analytic framework is elaborated in [4]. In the next chapter, we expand the analysis by including capacity mechanism within the same analytic framework.

3.1 System with only thermal generation

Classical theoretical work in energy economics [12] have shown how energy-only markets based on marginal cost pricing give cost-recovery in equilibrium for conventional generators. A crucial element in the solution is value of lost load (VOLL) pricing, which in theory dictates the profitability of peaker generation, and also influences the optimal capacities of all other generators in the system. Optimality conditions for the peaker provides the following universal relation between price of load shedding p_s and duration of load shedding t_s in perfect markets [13]:

$$t_s = \frac{F_p}{p_s - v_p} \approx \frac{F_p}{p_s} \quad (1)$$

where F_p is the annual fixed cost of the peaker, given in €/MW/yr, p_s is the price set by load shedding and v_p is the variable cost of the peaker. As can be observed from (1), any regulated price cap ($p_s < VOLL$) will lead to longer duration of load shedding, unless additional payments for firm generation are introduced. Moreover, a price cap leads to less capacity installed in equilibrium, as seen directly from the load duration curve in Figure 3.

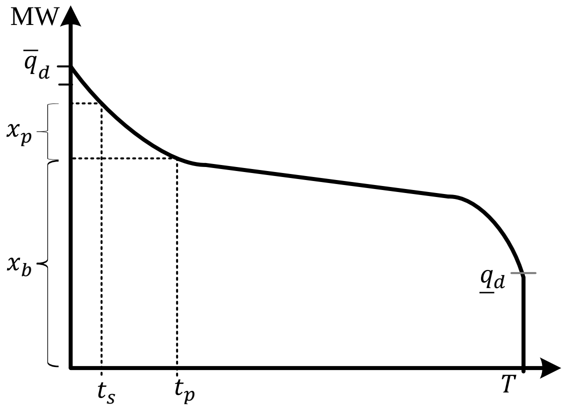

Figure 3. Load duration curve (q_d) with durations (t) and optimal capacities (x) of load shedding (subscript s), peaker (subscript p) and baseplant (subscript b).

A baseload plant has lower marginal cost than the peaker and will therefore always earn money when the peaker is operating. It can be shown that the optimal duration of the peaker is [13]:

$$t_p = \frac{F_b - F_p}{v_p - v_b} \quad (2)$$

where subscript b denotes the baseplant. The corresponding optimal baseload capacity x_b can be derived directly from the load duration curve.

The optimality conditions (1) and (2) are derived from either system optimal conditions (minimizing system cost of electricity) or from profit maximization of each plant, see e.g. [14].

3.2 Adding competitive VRE to the system

We now introduce a variable renewable energy source to the system, let it be wind power to be specific. Figure 4 shows the duration curve for the net demand with high amounts of wind power. The shaded line is the duration curve of the demand, while the black curve is the duration curve of net demand which is the demand seen by the thermal generators after subtracting the wind generation . In our example, we see that the net demand is negative for some hours of the year, which will be the result if the capital costs of wind power is low enough. In these hours, the thermal generators are shut off, and wind power must be curtailed to meet the load and keep the frequency at a stable level. Due to expected continued cost reductions for wind and solar technologies, a common result of European scenario studies is that the optimal generation mix leads to some renewable curtailments see e.g. [1][15]. The corresponding level of curtailment will depend on the available level of flexibility.[1][15].

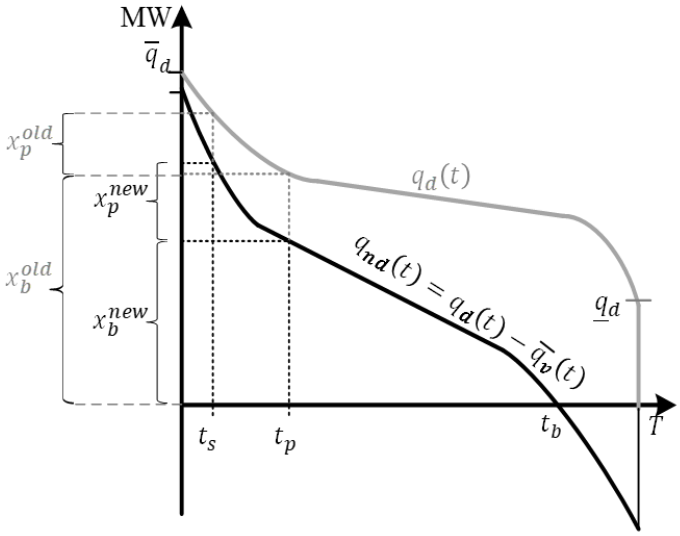

Figure 4. Load duration curve for demand (q_d - grey line) and net demand (q_{nd} - black) line for a system with two conventional generators ("peak" and "base") and one VRE plant (subscript v). The optimal capacities of peak and base load plants with and without VRE are indicated in the figure as "new" respectively "old". $\overline{q_t}(t)$ is the uncurtailed VRE generation time series. Note: "t" is defined as duration based on either demand or net demand. It is not chronological time step.

A logical conclusion from a perfect market perspective is that optimality conditions for the peaker and the baseload plant will not change when wind enters the system. This is due to the simple fact that all generators only earn money when the price in the market is higher than their marginal costs. Therefore, the optimal durations of load shedding and peaker operation are independent of wind installation and, consequently, equations (1) and (2) still holds as long as both technologies are present in the system.

In the net demand figure, the duration of the baseload plant is denoted t_b. To the right of this point, the net demand is negative, and the price is therefore zero. In this segment, the wind power plant does not earn money. The duration of the baseload plant is thus derived from the optimality condition of the wind generator and can be expressed analytically using system cost minimization and generator profit maximization, as shown in the following sections. As more and cheaper VRE will be available in the system, the net demand curve will be pushed down further, and therefore tb further to the left. For given optimality conditions (t_s and t_p constants), it can be observed that the optimal mix of thermal generation will change accordingly, and that there will be relatively more peaker plant capacity, while more of the base load plants will operate as "mid-merit" plants.

Our equations are derived under the assumption that there are *G* thermal generator technologies with the same cost and performance characteristics, and none of these technologies are pushed completely out of the market by the entrance of VRE: rather, they are still part of the optimal generation mix. If a type of generator technology leaves the market entirely because of VRE, then optimal durations must be recalculated with the new plant portfolio.

3.2.1 System cost minimization

By assuming fixed demand and deterministic conditions, the cost minimization problem of a system with G thermal generators and one wind power plant v can be expressed as:

$$\min_{x_g, x_v} C = \sum_{i=1}^{G} \left[F_{gi} x_{gi} + v_{gi} \int_0^T q_{gi}(t)\, dt \right] + F_v x_v + p_s \int_0^T q_s(t)\, dt \tag{3}$$

where x is capacity, F is annual fixed cost, v_{gi} is variable cost of (thermal) generator i, q_s is load shedding. To derive the system optimality condition for the VRE plant from the system objective (3) we derivate with respect to the installed capacity of wind generation:

$$\frac{dC}{dx_v} = 0 \Longrightarrow F_v = \frac{d}{dx_v} \left[-p_s \cdot \int_0^{t_s} q_s\left(q_{vj}(t)\right) dt - \sum_{i=1}^{G} v_{gi} \cdot \int_0^{t_{gi}} q_{gi}\left(q_v(t)\right) dt \right. \tag{4}$$

where the instantaneous load shedding and conventional generation are a function of the VRE power output, i.e. the terms $q_s\left(q_v(t)\right)$ and $q_{gi}\left(q_v(t)\right)$ express that the load shedding and conventional generation are functions of the VRE output.

By assuming linear scaling of VRE output, the VRE generation profile becomes independent of the capacity of the VRE generator, and we can insert $q_v(t) = CF_v(t) \cdot x_v$ into (4), where $CF_v(t)$ is the Capacity Factor of VRE output at time instant t. If there is only one type of VRE generator in the system, each additional kWh produced will reduce the output of the marginal generator with the same amount, while all other generator outputs are unchanged. Eq. (4) can then be written as:

$$F_v = p_s \cdot \int_0^{t_s} CF_v(t)\, dt + v_{g1} \cdot \int_{t_s}^{t_{g1}} CF_v(t)\, dt + \sum_{i=2}^{G} v_{gi} \cdot \int_{t_{gi-1}}^{t_{gi}} CF_v(t)\, dt \tag{5}$$

The individual integrals are equal to the length of the period multiplied by the average VRE capacity factor over the period, which is known from the resource model (analytical or numerical model) of the VRE plants:

$$\int_{t_1}^{t_2} CF_v(t)\, dt = (t_2 - t_1) \cdot CF_v^{[t_1, t_2]} \tag{6}$$

where $CF_v^{[t_1,t_2]}$ is the average capacity factor of the VRE plant during time segment $[t_1, t_2]$ of the net load duration curve. Inserted into (4), the optimality condition of the VRE plant becomes:

$$F_v = p_s t_s CF_v^{[0,t_s]} + v_{g1}(t_{g1} - t_s)CF_v^{[t_s,t_{g1}]} + \sum_{i=2}^{G} v_{gi}(t_{gi} - t_{i-1})CF_v^{[t_{gi-1},t_{gi}]} \tag{7}$$

Since the VRE output here is assumed to scale linearly with size, the optimal VRE plant will either have zero capacity or a capacity that leads to some curtailment of generation. This is simply because the duration of the different thermal generators in equilibrium does not change as a result of VRE capacity since they must recover their costs according to (1) and (2). So, the duration of the different price segments are unchanged. Thus, if the net benefit of a small VRE plant is positive, it will be profitable to increase the size until the net benefit becomes zero. This will first happen when so much of the output is curtailed so that the net market income equals the annualized capital cost. For real cases of large power systems, this is of course a large simplification, as the best VRE sites should be utilized first, and thus the resource availability would decrease gradually. Nevertheless, this approach is commonly applied in more detailed generation expansion planning studies [1][16][20].

In the case with only one VRE power plant (or aggregated representation of several VRE plants), the optimality condition is given in (7) and the only unknown is the duration of generator *G*, i.e. the generator with lowest variable costs. As explained above, the optimal duration of *G* is less than a full year, and given by rearranging (7):

$$t_{gG} = t_{gG-1} + \frac{1}{v_{gG} CF_v^{[t_{gG-1},t_{gG}]}} \left[F_v - p_s t_s CF_v^{[0,t_s]} - v_{g1}(t_{g1} - t_s)CF_v^{[t_s,t_{g1}]} - \sum_{i=2}^{G-1} v_{gi}(t_{gi} - t_{i-1})CF_v^{[t_{gi-1},t_{gi}]} \right] \tag{8}$$

Thus, under the assumption of one type of VRE plant which scales linearly, it is the duration t_{gG} that determines its optimal capacity x_v. The duration t_{gG} is the number of hours of the year with net demand higher than zero. The optimal VRE capacity x_v is the capacity that leads to net demand of zero at exactly t_{gG}, and can be found relatively straightforwardly from the load and VRE resource data [4].

Consider now a small generation portfolio of one peak power plant *p*, one base power plant *b* and one VRE power plant v. Eq. (8) gives the duration of the cheapest thermal generator, which in this case is baseload *b*. Rewritten for the two generators + VRE system, we get:

$$t_b = t_p + \frac{1}{v_b CF_v^{[t_p,t_b]}} \left[F_v - p_s t_s CF_v^{[0,t_s]} - v_p(t_p - t_s)CF_v^{[t_s,t_p]} \right] \tag{9}$$

The optimality conditions for this system are also illustrated in Figure 4. As visualized in the figure, optimal VRE integration does not change the optimal duration of the peaker and load shedding, but the optimal thermal plant capacities are altered. In the illustrative case, the base generator capacity is reduced significantly while the peak generator capacity is marginally increased, as a result of the VRE variability. Such effects of VRE integration are well known from more detailed studies based on capacity expansion models, see e.g. [21] for a case study based on the electricity market in Texas, where the revenues of baseplant generators are found to decrease as a function of VRE penetration. Maximum load shedding is also higher with VRE, to ensure optimal duration of the peaker with the changed net demand.

3.2.2 Profit maximization

Given a market where VRE generators are fully exposed to the electricity market prices, their profit function becomes:

$$\begin{aligned} \pi_v = AR_v - AC_v &= \int_0^T p(t) q_v(t) dt - F_v \cdot x_v \\ &= x_v \int_0^T p(t) CF_v(t) dt - F_v \cdot x_v \end{aligned} \tag{10}$$

$$\pi_v = 0 \Rightarrow F_v = \int_0^T p(t) CF_v(t) dt$$

Full cost recovery requires that the long-term profit π_{vj} is zero:

$$\pi_v = 0 \Rightarrow F_v = \int_0^T p(t) CF_v(t) dt \tag{11}$$

We see from (11) that the VRE power plants exactly recovers their costs in a market based on marginal cost pricing, and this also corresponds to the system optimum (5). Maximization of the profit function (10) gives the same result:

$$\frac{\delta \pi_{vj}}{\delta x_{vj}} = 0 \Rightarrow F_{vj} = \int_0^T p(t) CF_{vj}(t) dt \tag{12}$$

which shows that market based VRE investments reach an equilibrium at system optimum where it is not profitable to increase the capacity further. As in the previous section, this result is obtained under the assumption of linear VRE output scaling.

It is well known from the literature that the short-term effect of VRE is a shift towards lower clearing prices. However, even with the inclusion of VRE in the system, the requirements (1) and (2) for conventional generators must be met for the market to be in equilibrium[6]. This means that their durations in equilibrium will not change since the duration is not a function of the shape of the (net) demand curve. However, their optimal generator capacities will not

[6] This can easily be shown e.g. for generator 1: The shedded load is now expressed as $P_s(t) = P_d(t) - \sum_G P_{gi}(t) - \sum_V P_{vj}(t)$, where the last term is the production from the VRE plants. The VRE production is independent of the conventional generation capacity, so the optimality condition $\frac{dC}{dP_{gi}} = 0$ remains unchanged.

stay constant since the net demand curve seen by the conventional generators will be shifted downwards and change form as more VRE plants enter the system.

Looking ahead towards 2040-2050, it is a plausible scenario that it may be optimal to build so much capacity of VRE that it leads to some curtailment of the output as assumed in this analysis. Even when leaving power flow and unit commitment constraints out of the calculations, system-optimal VRE capacity may cause significant number of hours with zero prices in the future.

The energy input to the VRE power plant is assumed to be scalable with no change in the resource availability pattern. Moreover, economics of scale is not accounted for. This means that if an infinitesimal small VRE capacity is profitable, then the profit will increase linearly as a function of VRE capacity until the point where VRE curtailment starts. By increasing the capacity beyond this level, the profit will eventually start to decline and reach zero at system optimum as given by Eq. (11). This also means that if there is only one VRE owner in the system, and this owner acts strategically, the capacity which maximizes his profit will be less than the system optimum. But this will attract other VRE investors to the market until the annual profit is zero for all actors, since a marginal increase in VRE capacity reduces the income for all VRE plants by increasing the number of hours with zero price in the market.

3.3 Inclusion of energy storage

We now let energy storage enter the market. Storage links energy contents in time, and is therefore not possible to include directly in a duration curve model based on sorted data. We can model power capacity x_e and round-trip efficiency η_e explicitly, but not the kWh constraint. Therefore, we have chosen to relax the energy storage constraint, and model the system under some simplified operating assumptions for the storage. A range of different operating assumptions for the storage is elaborated on in detail in [4]. Here, we present a simple variant of storage operation which assumes that the storage has infinite kWh capacity, but limited kW capacity and efficiency, and can be used for shifting surplus VRE energy to any other time of the year, as illustrated in Figure 5.

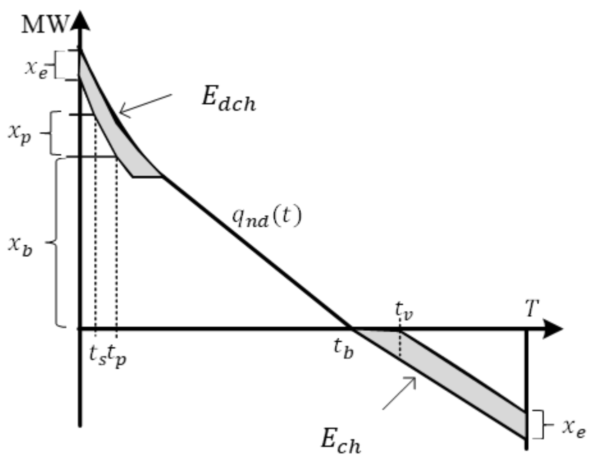

Figure 5. Duration curve of net demand, where storage is used for replacing thermal energy with surplus VRE. A new price segment occurs $[t_b, t_v]$, where charging of EES is the marginal load. E_{ch} is discharged energy and E_{dch} is charged energy. Annual storage balance yields $E_{dch} = \eta_e \cdot E_{ch}$.

The operational assumptions are illustrated in Figure 5, which give rise to the following storage operation segments:

- Period $[t_v, T]$: EES stores surplus VRE energy at full charging capacity. In this segment, VRE is the marginal generator and the price is consequently zero. t_v is defined as the time when EES reaches full charging.
- Period $[t_b, t_v]$: EES is the marginal load, and it sets the market price based on the marginal value of stored energy. This depends on what the stored energy replaces. In our illustrated example, marginally more stored energy replaces baseplant generation. The price is therefore given by the marginal cost of baseplant energy, adjusted for storage losses.
- Rest of the period $[0, t_b]$: neither EES nor VRE are the marginal generators, and the price segments are unchanged from the case without EES.

3.3.1 System optimality conditions

The optimal duration of the peaker and the base plant is unchanged when storage of VRE energy is introduced, since the stored energy replaces energy from the base plant. The optimality condition for the VRE power plant is found similarly to Section 3.2.1, but it is necessary to also take into account how a marginal increase in VRE capacity marginally increases the amount of stored energy that is used to replace energy from the base plant:

$$F_v = p_s t_s \cdot CF_v^{[0,t_s]} + v_p(t_p - t_s) \cdot CF_v^{[t_s,t_p]} + v_b(t_b - t_p) \cdot CF_v^{[t_p,t_b]} + v_b \frac{d}{dx_e} \int_{t_p}^{t_b} q_{dch}(t)dt \tag{13}$$

$$= p_s t_s \cdot CF_v^{[0,t_s]} + v_p(t_p - t_s) \cdot CF_v^{[t_s,t_p]} + v_b(t_b - t_p) \cdot CF_v^{[t_p,t_b]} + \eta_e v_b \frac{d}{dx_v} E_{ch}(x_v, x_e)$$

where we have introduced the annual energy storage conversion:

$$E_{dch} = \eta_e \cdot E_{ch}. \tag{14}$$

The last term on the right-hand side in (13) can be simplified by splitting up the charging period into the intervals $[t_b, t_v]$ and $[t_v, T]$. During $[t_v, T]$, there is more potential VRE energy already than needed, so a marginal increase in VRE capacity gives no more charging, hence $\frac{\delta}{\delta x_v} E_{ch}^{[t_v,T]} = 0$. During $[t_b, t_v]$ on the other hand, all the marginally added VRE energy will be used to charge the EES since the EES is not fully utilized. The marginal increase in VRE energy is dependent on the capacity factor in the period, since $q_v = CF_v x_v$, hence $\frac{\delta}{\delta x_v} E_v^{[t_b,t_v]} = \frac{\delta}{\delta x_v} CF_v^{[t_b,t_v]} x_v(t_v - t_b) = CF_v^{[t_b,t_v]}(t_v - t_b)$ Eq. (13) can therefore be rewritten:

$$F_v = p_s t_s \cdot CF_v^{[0,t_s]} + v_p(t_p - t_s) \cdot CF_v^{[t_s,t_p]} + v_b(t_b - t_p) \cdot CF_v^{[t_p,t_b]} \qquad (15)$$

$$+ \eta_e v_b(t_v - t_b) \cdot CF_v^{[t_b,t_v]}$$

Eq. (15), has two unknowns, t_b and t_v. We will now show that t_v is found directly from the optimality condition for the EES, which is derived in the same way as for the other units in the system:

$$F_e = p_s t_s + v_p(t_p - t_s) + v_b \frac{d}{dx_e}\int_{t_p}^{t_b} q_{dch}(t)dt \qquad (16)$$

$$= p_s t_s + v_p(t_p - t_s) - v_b t_p + \eta_e v_b \frac{d}{dx_e} E_{ch}(x_v, x_e)$$

We can simplify (16) further by noting that the charging process runs at a lower capacity than available during $[t_b, t_v]$. A marginal increase in EES capacity during that period leads to nothing, so $\frac{\partial}{\partial x_e} E_{ch}^{[t_b,t_v]} = 0$. In the last period of the year $[t_v, T]$ a marginal increase in EES capacity gives full utilization, i.e. $\frac{\partial}{\partial x_e} E_{ch}^{[t_v,T]} = (T - t_v)$. We therefore get:

$$F_e = p_s t_s + v_p(t_p - t_s) - v_b t_p + \eta_e v_b(T - t_v) \qquad (17)$$

$$\Rightarrow t_v = T - \frac{1}{\eta_e v_b}\left(F_e + v_b t_p - p_s t_s - v_p(t_p - t_s)\right) \qquad (18)$$

Eq. (18) is the optimality condition for the EES, expressed by the duration t_v, which is the time instant when the negative net demand is equal to the EES capacity. Equivalently, t_v is the duration of full VRE energy utilization. The duration t_v can be found directly from the system parameters and the known durations t_s and t_p. When t_v is found, the duration of the base plant t_b can be found indirectly from (15), which is the optimality condition for VRE. When we have t_b and t_v, it is straightforward to find the optimal VRE capacity and EES capacity from the net demand curve.

3.3.1.1 Cost recovery of EES

As already mentioned, we limit our analysis to cases where no generator types are entirely pushed out of the market, Both the peaker and base plant will be present in the system, and their optimality conditions are unchanged. VRE and EES will cause a change in the capacity and generation of the base and peaker, but the duration of load shedding (optimality condition for the peaker) and duration of the peaker (optimality condition for the base plant) are both unchanged.

To investigate the cost recovery and optimality conditions in the market, we first express the annual profit function of the EES:

$$\pi_e = \int_0^T p(t)\big(q_{dch}(t) - q_{ch}(t)\big)\,dt - F_e \cdot x_e \tag{19}$$

$$\pi_e = 0 \Longrightarrow \int_0^T p(t)\big(q_{dch}(t) - q_{ch}(t)\big)\,dt = F_e \cdot x_e \tag{20}$$

In system optimum, the profit of each EES owner is maximized:

$$\frac{d\pi_e}{dx_e} = 0 \Longrightarrow F_e = \frac{d}{dx_e}\left[\int_0^T p(t)\big(q_{dch}(t) - q_{ch}(t)\big)\,dt\right] \tag{21}$$

$$\Longrightarrow F_e = p_s \frac{dE_{dch}^{[0,t_s]}}{dx_e} + v_p \frac{dE_{dch}^{[t_s,t_p]}}{dx_e} + v_b \frac{dE_{dch}^{[t_p,t_b]}}{dx_e} + p^{[t_b,t_v]} \frac{dE_{ch}^{[t_b,t_v]}}{dx_e} + p^{[t_v,T]} \frac{dE_{ch}^{[t_v,T]}}{dx_e} \tag{22}$$

where $p^{[t_b,t_v]}$ refers to the (still unknown) market price between time t_b and t_v, and so on. The solution of (22) can be found by analyzing each time period of the year, according to the right-hand side of (22) and the illustration in Figure 5:

$[0, t_s]$: The EES is already fully utilized. A marginal increase in the EES capacity will be therefore also be fully utilized over the whole period, hence $\frac{d}{dx_e} E_{dch}^{[0,t_s]} = t_s$

$[t_s, t_p]$: Similar to above, the EES is already fully utilized. A marginal increase in the EES capacity will therefore also be fully utilized over the whole period, hence $\frac{d}{dx_e} E_{dch}^{[t_s,t_p]} = t_p - t_s$

$[t_p, t_b]$: The EES is the marginal generator. A marginal increase in the EES capacity will lead to an increase in the delivered energy constrained by the available energy given by the annual storage balance $E_{dch} = \eta_e \cdot E_{ch}$.

$[t_b, t_v]$: The EES is charging less than its capacity. A marginal increase in EES capacity will therefore not change anything[7], hence $\frac{d}{dx_e} E_{ch}^{[t_b,t_v]} = 0$

$[t_v, T]$: The EES is charging at full capacity. A marginal increase in EES capacity will therefore increase the available energy for charging by the amount $\frac{d}{dx_e} E_{ch}^{[t_v,T]} = T - t_v$. The price in this period must be zero, $p^{[t_v,T]} = 0$, since there is more potential VRE energy than needed, hence $p^{[t_v,T]} \cdot (T - t_v) = 0$.

[7] Note that this is under the assumption of a perfect competitive market consisting of many equal EES units that are all price takers, i.e. none of them is big enough to influence prices or durations on their own.

Equation (22) can thus be written:

$$F_e = p_s t_s + v_p(t_p - t_s) + v_b \frac{dE_{dch}^{[t_p,t_b]}}{dx_e} \tag{23}$$

Inserting the annual storage balance $E_{dch} = \eta_e \cdot E_{ch}$:

$$F_e = p_s t_s + v_p(t_p - t_s) + v_b \frac{d}{dx_e}\left[\eta_e E_{ch}(x_v, x_e) - x_e t_p\right] \tag{24}$$

$$= p_s t_s + v_p(t_p - t_s) - v_b t_p + \eta_e v_b \frac{dE_{ch}}{dx_e}$$

$$= p_s t_s + v_p(t_p - t_s) - v_b t_p + \eta_e v_b (T - t_v)$$

which is identical to the system optimal solution (17).
We also need to show that costs are exactly recovered in the profit-maximizing solution. Inserting known prices and volumes into (20) yields:

$$F_e \cdot x_e = \int_0^T p(t)\big(q_{dch}(t) - q_{ch}(t)\big)\, dt \tag{25}$$

$$F_e \cdot x_e = p_s E_{dch}^{[0,t_s]} + v_p E_{dch}^{[t_s,t_p]} + v_b E_{dch}^{[t_p,t_b]} - p^{[t_b,t_v]} \cdot E_{ch}^{[t_b,t_e]} \tag{26}$$

$$F_e \cdot x_e = p_s x_e t_s + v_p x_e(t_p - t_s) + v_b(\eta_e E_{ch} - x_e t_p) - p^{[t_b,t_v]} \cdot E_{ch}^{[t_b,t_e]} \tag{27}$$

The price during the part of the charging period $[t_b, t_v]$ must be determined. The marginal cost in the period is zero, since there are VRE curtailments. One could then falsely conclude that the price also will be zero. However, there is more EES charging capacity available than needed in this period, since the EES is not fully utilized during $[t_b, t_v]$. In a perfect competitive market with many EES owners, they will bid against each other until the price reaches the marginal value of stored energy or the opportunity cost. This cost is given by the marginal generator in the period where an additional amount of stored energy would be discharged, in our case the base plant. By accounting for storage losses we obtain the price $p^{[t_b,t_v]} = \eta_e v_b$ which is inserted into (27):

$$F_e \cdot x_e = p_s x_e t_s + v_p x_e(t_p - t_s) + v_b(\eta_e E_{ch} - x_e t_p) - \eta_e v_b E_{ch}^{[t_b,t_e]}$$

$$\Longrightarrow F_e \cdot x_e = p_s x_e t_s + v_p x_e(t_p - t_s) - v_b x_e t_p + \eta_e v_b [E_{ch} - E_{ch}^{[t_b,t_e]}]$$

$$\Longrightarrow F_e \cdot x_e = p_s x_e t_s + v_p x_e(t_p - t_s) - v_b x_e t_p + \eta_e v_b E_{ch}^{[t_e,T]}$$

$$\Rightarrow F_e \cdot x_e = p_s x_e t_s + v_p x_e (t_p - t_s) - v_b x_e t_p + \eta_e v_b x_e (T - t_e)$$

$$\Rightarrow F_e = p_s t_s + v_p (t_p - t_s) - v_b t_p + \eta_e v_b (T - t_e) \quad (28)$$

which is equal to the optimal system solution and the profit maximizing solution.

3.3.1.2 Cost recovery of VRE

The general profit function for VRE is given in (10). Inserting the known prices for the different time segments, we get:

$$\pi_v = p_s CF_v^{[0,t_s]} x_v t_s + v_p CF_v^{[t_s,t_p]} x_v (t_p - t_s) + v_b CF_v^{[t_p,t_b]} x_v (t_b - t_p) \quad (29)$$

$$+ \eta_e v_b CF_v^{[t_b,t_v]} x_v (t_v - t_b) - F_v x_v$$

Cost recovery, $\pi_v = 0$, gives the same result as system optimum (15):

$$F_v = p_s CF_v^{[0,t_s]} t_s + v_p CF_v^{[t_s,t_p]} (t_p - t_s) + v_b CF_v^{[t_p,t_b]} (t_b - t_p) \quad (30)$$

$$+ \eta_e v_b CF_v^{[t_v,t_e]} (t_v - t_b)$$

We see directly from (29) that this result is also obtained by maximizing the VRE profit, $\frac{d\pi_v}{dx_v} = 0$.

3.3.2 EES for general price arbitrage

In Section 3.3, the optimality conditions for the EES was derived for the case where it is merely used for storing surplus VRE energy. In the general case, the EES can increase its value by using its available capacity for shifting energy between other time periods as well. In Figure 6, we have illustrated the price arbitrage option but letting the EES charge baseload power to replace peaker generation. Another modification from Figure 5 is that the storage VRE energy is assumed for illustrative purposes to only replace baseload power.

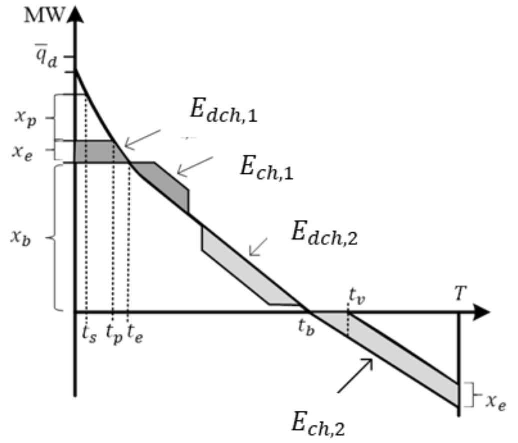

Figure 6. Duration curve of net demand, where storage is used for replacing baseplant energy with surplus VRE (light grey areas) and for replacing peaker energy with baseplant energy (dark grey areas). t_e is the duration of discharging the EES when charged previously by baseplant energy.

If we write out the optimality conditions for the baseload plant, the storage and the wind power plant, it is shown in [4] how they form a set of 4 non-linear equations with 4 unknowns, which are the duration curve segments given in Figure 6 . Note that the optimality condition of the peaker must be unchanged from before, as its cost recovery still comes from the load shedding period. There is a new price segment $[t_p, t_e]$ where the EES is the marginal generator. The price in this period is equal to the marginal cost of discharging EES when charged by baseplant energy. Hence, the price in that period must be

$$p^{[t_p,t_e]} = v_b/\eta_e. \tag{31}$$

When the optimal durations of the different price segments are found, we can easily calculate the optimal plant capacities from the net demand duration curve. See [4] for detailed analysis of this case.

3.4 Illustrative example

A small example has been constructed to illustrate how the optimal generation capacities and market prices develops when wind and storage enters a thermal system. The analyzed system consists of a peaker (OCGT) a baseplant (CCGT), a VRE plant (offshore wind) and a storage unit (Li-Ion Battery Bank) which supplies an inflexible demand. Hourly aggregated European wind and demand data are extracted from the EU JRC EMHIRES database [19] and ENTSO-E database [17], respectively. Maximum load is scaled to 100 MW for illustrative purposes. Cost and component data are found in Table 1, which is mainly based on values from the EU Reference Scenario 2016 [18] and NREL's battery cost study [20], see [4] for complete parameter description.

Parameter	Value	Unit
F_i , $i \in [p, b, v, e]$	[45 75 299 109]	1000 €/MW/yr
$v_{,i}$, $i \in [p, b]$	[155.3 103.2]	€/MWh
η_e	81	%
p_s	3000	€/MWh

Table 1. Cost and component parameters. F is annual fixed costs, v is variable cost, η_e is storage efficiency, p_s is price for load shedding. Subscript p is peaker, b is baseplant, v is VRE, and e is EES.

The analytical model has been used for calculating optimal durations and component capacities for three separate cases

1. Thermal only. Ref. Section 3.1
2. Thermal+wind. Ref Section 3.2
3. Thermal+wind+storage.
    a. EES for surplus VRE. Ref Section 3.3.1
    b. EES for general price arbitrage. Ref. Section 3.3.2

Case 1: Thermal only
In all cases, the optimal duration of load shedding is given by the optimality condition of the peaker, eq. (1), which becomes $t_s = 15$ hours. Similarly, the optimal duration of the peaker becomes $t_p = 575$ hours, according to eq. (2). The optimal plant capacities are shown in Figure 8 and can be derived directly from the load duration curve, see Figure 3.

Case 2: Thermal+wind
With competitive costs for wind power and linear scaling of its output, there will be some hours with zero prices, according to eq. (9). This is a non-linear function of the times series for wind and demand, which must be solved with respect to the baseplant duration. In our case, the optimal baseload duration becomes approximately 6000 hours, which means that the price is zero for 2760 hours of the year. The other durations (t_s and t_p) are unchanged according to our model. Optimal plant capacities are easily derived from the net load duration curve, as illustrated in Figure 4. For this case, the optimal wind installation almost matches the maximum demand, pushing out some baseplant capacity and doubling the need for peaker capacity, as shown in Figure 8.

Case 3a: Thermal+wind+storage (EES for surplus VRE)
With storage, we get a new price segment where the storage is the marginal load, according to the analytical model presented in the previous section. The duration of load shedding t_s and t_p remains the same. Storage triggers more wind power capacity and the need for thermal capacity is reduced (Figure 8). The optimal storage operation leads to flattening of the price variations but the reduction in the average price is low compared to the isolated effect of wind power alone, as is evident from Figure 7. The introduction of wind alone reduced average prices by approximately one third, while storage only caused a further 0.5% improvement. More importantly, both wind power and storage lead to significantly lower emissions since a substantial part of the thermal generation over the year is related to wind. Without storage, the resulting wind share of consumption was about 62 % (accounting for curtailments), while

storage caused an additional increase to 72 % in the example.

Figure 7. Price duration curves for Case 1, 2, and 3a. Weighted average prices are: "Thermal only" 115 €/MWh, "add wind" 81.6 €/MWh, "add wind & storage" 81.4 €/MWh.

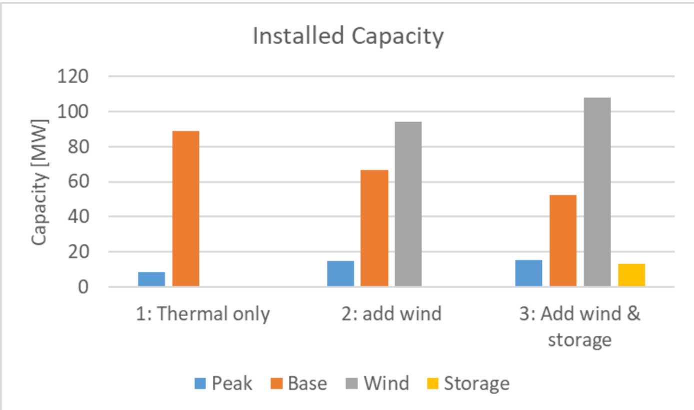

Figure 8. Optimal installed capacities for Case 1, 2, and 3a.

<u>Case 3b: Thermal+wind+storage (EES for general price arbitrage)</u>

In this case, the EES is also used for shifting energy from the periods where the baseplant set the price to periods with higher prices in the market, as illustrated in Figure 6. This operation strategy creates another new price segment where EES discharging sets the price according to eq. (31). The resulting price duration curve for the example is shown in Figure 9, where we clearly see how the EES now contributes to leveling the price level at both ends of the scale: During periods with high wind generation, it lifts the price by being the marginal load, while in the high load / low wind periods, it reduces the price level by replacing peaker generation by stored baseplant energy. As for Case 3a, the overall effect of the storage on the average price is very small compared to the effect of introducing competitive wind alone.

Figure 9. Price duration curves for Case 1, 2, and 3b. The blue curve follows the red curve at the left part of the figure (From hour 0 to 6000).

IV. IMPACTS OF CAPACITY PAYMENTS

In the previous section, we have shown that, in an energy only paradigm, the optimal duration of load shedding and therefore the optimal size of the last peaking unit are dependent on VOLL and the fixed costs of the cheapest peaker ($t_s \approx \frac{F_p}{p_s}$). Interestingly, generation capacities that are optimal for the system as a whole also lead to an adequate profit for all players, even in the presence of VRE or EES. In practice however, there may be many reasons why generation capacities, and in particular the size of the last marginal unit is smaller than desired. Those reasons include: energy policy (e.g. VOLL is difficult to estimate and to justify), reliability (capacity contribution of generators may not be well reflected by their installed capacity), system services (black-start, voltage support, primary reserve etc.). However, such reasons to change generation capacities will bring the system out of its energy-only optimal situation and lead to inadequate revenues unless additional payments for firm generation are introduced. In this section we do not cover how capacity markets are organized and administered. Rather, we study how adding capacity constraints modifies the elements we are mostly interested in, namely optimal generation capacities, profitability of market players and energy prices.

4.1 The case of conventional generators

When moving from the energy only paradigm, the main input becomes either the required level of capacity during peak load to achieve an acceptable expected duration of blackouts. This level of capacity is determined administratively [22] and usually comes from an engineering calculation (probabilistic reliability assessments) and/or economic arguments, both of which are outside the scope of this paper. As such, using this capacity level as an input of the capacity expansion phase is the starting point of modern capacity markets [22].

Starting from the equations of the previous section, we first add a simple capacity constraint on top of the energy-only approach, with conventional generators only. In that case, the unconstrained capacity minimization problem becomes a constrained optimization problem of the Lagrangian form to account for the capacity constraint $x_p + x_b \geq$ R:

$$\mathcal{L}_{exp}(x_p, x_b, \lambda) = C(x_p, x_b) + \lambda \cdot (x_p + x_b - R) \tag{32}$$

When this constraint is active, namely when R is above the energy-only total capacity, the following conclusions hold. First, the peaker capacity only increases to fulfill the capacity constraint. On top of that, adding the constraint leads to a profit loss for each type of generator. Per unit capacity, the profit for each generator, that is 0 in the energy-only case, now becomes

$$\pi_g/x_g = F_p - q_d^{-1}(R)(v_s - v_p) \tag{33}$$

When adding reserve capacity in the system, $t_s = q_d^{-1}(R)$ is now the new time at which the system starts to shed load. For each type of conventional generator, the profit loss against the case with no capacity constraint is therefore a decreasing function of R, as described in the figure below.

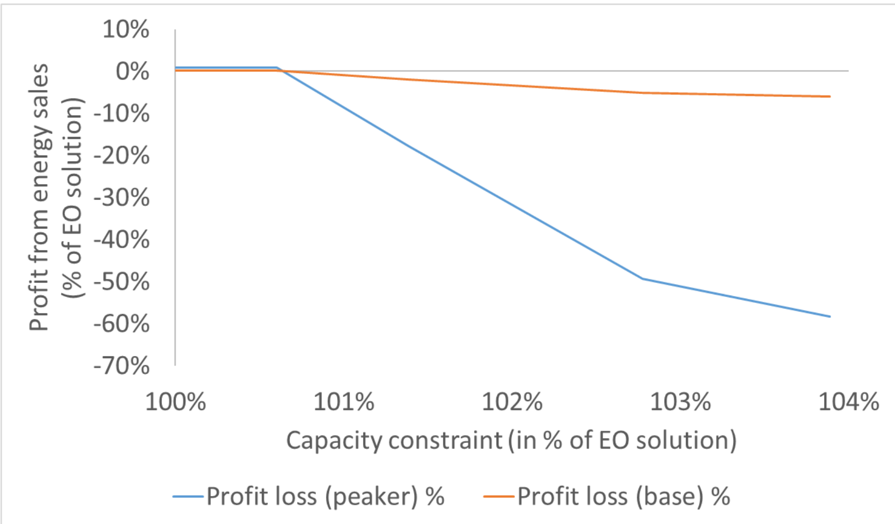

Figure 10. Relative impact of the capacity constraint (x-axis) on the profit of the generators (y-axis). The capacity constraint is 100% when it leads to the optimal capacity in the energy-only (EO) optimum.

The prices that apply for each time segment ($[0, t_s]$, $[t_s, t_p]$ and $[t_p, T]$) still correspond to the variable cost of the marginal generator (or VOLL during $[0, t_s]$). Since those prices do not change but the duration does, it leads to a profit that is no longer 0. Therefore, capacity payments must be paid to each generator per installed MW, to restore their profit. This is easy to verify if the fixed costs of each generator are reduced by the same quantity in equation (1) and (2): t_p will not change while t_s will. Interestingly, one can see that the relative impact of the capacity constraint is major for the peaker; in other words, capacity payments have to be well designed to avoid a distortion of individual profits.

Note that the capacity contribution of certain types of generators may be limited to account for forced-outage rates. One can show that including a capacity contribution parameter α for the base generator leads to the following durations:

$$t_p = \frac{(F_b - \alpha F_p) + (\alpha - 1)t_s\,(v_s - v_p)}{v_p - v_b} \; and \; t_s = q_d^{-1}\left(\frac{(\alpha-1)x_p + R}{\alpha}\right) \quad (34)$$

For a fixed value R of the constraint, one sees from Figure 11 that varying the value of α has a major influence on the capacity of the peaker, while the impact on the base generator is almost not visible using the same scale.

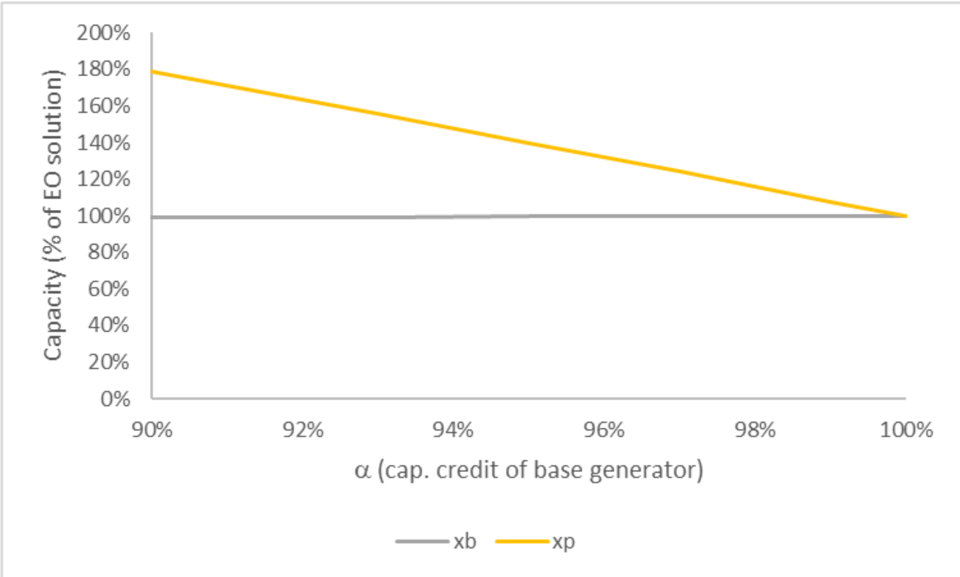

Figure 11. Relative capacity of the peaker (x_p) and the baseplant (x_b) for an decreasing capacity contribution of the baseplant α. In this example, VOLL is set to the (too) low value 500\$/MWh to better illustrate the impact of the capacity contribution.

Therefore, in addition to the actual value of the capacity constraint, the assumed capacity contribution of each generation technology is clearly another important parameter with impact on the installed generation capacity. Basically, this is because the revenue of the peaker depends on a limited number of hours that are highly priced (t_s).

4.2 The case with VRE

With VRE, total generation capacity covers the demand up to a limit when shedding happens; this limit is derived from t_s, the energy-only optimal duration of load-shedding. Total available generation capacity is given by

$$q_d(t_s) = x_b + x_p + CF_v(t_s) \cdot x_v \quad (35)$$

Therefore, one sees that when shedding happens, the capacity contribution of wind generation is not 100% or 1, but rather $CF_v(t_s) < 1$. Actually, for systems in equilibrium with high VRE contents, shedding will happen when $CF_v(t_s)$ is small, since it is the net demand curve that determines t_s (see Figure 4)

Once again, we study what is the impact of imposing a total generation constraint higher than the energy-only optimal capacity. The optimality conditions for all generators, $\frac{dC}{dx_i} = 0$, lead again to an increase of only peaker capacity. If the capacity contribution of VRE is deemed to be $\alpha_v < CF_v(t_s)$, then, the optimality conditions lead to:

$$
\begin{aligned}
t_b = t_p + \left(v_b CF_v^{[t_p, t_b]}\right)^{-1} \\
\cdot \Big(F_v - \alpha_v \mathrm{F}_b - v_s t_s (CF_v^{[0,t_s]} - \alpha_v) - v_p (t_p - t_s)(CF_v^{[t_s, t_p]} \\
- \alpha_v) - v_b t_p \alpha_v\Big)
\end{aligned}
\tag{36}
$$

We see that the inclusion of R has a marginal impact on the optimum capacity of VRE and of the base generator. For systems with relatively high levels of VRE, this is due to the contribution of VRE at the time of shedding that is small in equilibrium conditions; In addition, the revenue of VRE comes mostly from the hours in which there is conventional generation online, i.e. mostly from those hours when there is no shedding (when the peaker or base is marginal).

Therefore, in a system without EES, it may be important to pay capacity payments to conventional generators to restore their profit because a high share of their profits comes from the load shedding period; this is especially true for the peaker. Accordingly, the capacity payment to VRE generators should, as all other generators, be in proportion to their contribution at the time of load shedding [23][24], which means a smaller payment if not accompanied by dedicated storage.

V. CONCLUSIONS AND FURTHER WORK

In this work we have shown that, under certain assumptions, all plants recover their costs in a perfect energy-only market with competitive VRE resources and energy storage. This market solution gives the optimal generation mix which minimizes system costs. Moreover, we get the same result when modelling the expansion decisions of profit-maximizing generators and storage technologies in a fully competitive market. Our results therefore indicate that thermal generators, VRE, and EES can co-exist in regular energy-only markets. Due to the change in the net-load profile seen by the thermal generators, their capacity mix will change when VRE and storage enter the market. However, this effect is in principle the same as when new cheaper thermal generators enter the market and replace older and more expensive capacity.

Moreover, we have shown analytically that storage devices trigger more renewable capacity in the market. The presence of storage creates new price segments where renewables gain more profits. Moreover, by storing excess VRE energy, the EES helps reducing VRE curtailments and thereby reduces the number of zero price hours. On the other hand, the presence of storage in the market does not make a noticeable impact on the average price of electricity, but it does reduce the price variations over the year.

Finally, we have shown that adding a capacity constraint on top of the energy-only approach is effective in providing an additional level of capacity that could be deemed necessary by the system operator and regulators to ensure reliability under real-world conditions. However, we show that the last marginal unit capacity is highly influenced by the characteristics used to design the capacity constraint, namely total capacity and the ex-ante capacity contribution of each generator. There is limited impact on the profitability of the base load power plants if proper capacity payments are provided. There is also limited impact on renewable capacity. These capacity payments are an important share of the revenue mostly for conventional thermal generators. If energy storage is added to VRE generation, it can replace conventional generators as firm capacity, but the contribution in peak hours depends on the operation in the market; this last topic is an interesting avenue for further fundamental research. Moreover, for VRE dominated systems, resource adequacy should be reconsidered taking into account contributions from demand resources in addition to energy storage and generation technologies. The impact of storage on the equilibrium conditions systems with capacity requirements and inclusion of demand-response in the analytical framework are topics for further research.

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Appendix A Generalization to multiple VRE plants

In Section 3.2 the system optimal conditions was derived for a case with only one type of VRE power plant present in the system, e.g. onshore wind. When there are several VRE plants in the system with different characteristics, they will influence each other's optimality conditions as a result of their different time-varying power output and different fixed costs. The general optimality condition for one VRE plant j is given in eq. (7) which gives us one equation with one unknown, namely the duration of the conventional generator "G" with lowest variable cost, t_{Gg}. This is the time instant when the duration curve of the system net demand is zero. For a system with multiple VRE plants, this is expressed by:

$$q_{nd}(t_{gG}) = 0 \Rightarrow q_d(t_{gG}) - \sum_{j=1}^{J} x_{vj} \cdot CF_{vj}(t_{gG}) = 0 \tag{36}$$

This equation can be re-formulated to express t_{gG} as a non-linear function of the VRE capacities:

$$t_{gG} = f(x_{v1}, \dots, x_{vj}, \dots, x_{vJ})$$

The optimality condition for VRE plant j then becomes:

$$\begin{aligned} F_{vj} = p_{cap} t_s CF_v^{[0,t_s]} + v_{g1}(t_{g1} - t_s) \cdot CF_{vj}^{[t_s,t_{g1}]} \\ + \sum_{i=2}^{G-1} v_{gi}(t_{gi} - t_{gi-1}) \cdot CF_{vj}^{[t_{gi-1},t_{gi}]} \\ + v_{gG} \frac{d}{dx_{vj}} \left[x_{vj} \cdot (t_{gG} - t_{gG-1}) \cdot CF_{vj}^{[t_{gG},t_{gG-1}]} \right] \end{aligned} \tag{37}$$

which is a set with J coupled equations for J number of VRE plants.