Towards Carbon Neutrality and Energy Independence in Europe: Can New Storage and Renewables Push Fossil Fuels Out?

Milien Dhorne [123] Marc Baudry [12]

Work in progress presented during the 2022 PhD seminar
of the French Association of Energy Economists (FAEE)

Abstract

Variable and renewable energy (VRE) sources lie at the core of the European energy decarbonating and independence strategy. A larger share of renewable generation requires flexibility options to cope with production fluctuations. In this context, energy storage is acknowledged as a promising solution to cope with intermittency but its contribution to the power system is still uncertain. We investigate in this paper the development of energy storage solutions as dispatchable assets to compete with existing and future fossil fuel power plants. We present a theoretical model showing that storage can increase or decrease CO_2 emissions but may support the development of solar and wind. We confirm these results with a stochastic competitive equilibrium framework, calibrated on the current Western European power system, to derive the market value of new storage technologies and their impact on the power system. We estimate the long-term equilibrium of flexibility and renewable capacities under a coal phase-out policy. We subsequently analyze the CO_2 emissions and the fossil fuel consumption. We find evidence that the development of storage, stationary or vehicle-to-grid, is delayed by the competitive advantage of new gas power plants. We underline that storage provides moderate beneficial effect on CO_2 emissions or energy independence. However, our results suggest VRE development could in the long term be accelerated by storage, making a case for a smart design of transition policies.

Keywords: Energy transition, Energy storage, Power system flexibility, Fossil fuel power plants, Environmental policies

[1]EconomiX, Université Paris Nanterre
[2]Climate Economics Chair, Paris
[3]Ecole des Ponts ParisTech

1 Introduction

Tackling climate change requires immediate and ambitious changes in all economic sectors. In the European Union (EU), the energy sector is still accountable for more than one quarter of the greenhouse gas (GHG) emissions and positions as the first emitting sector[1]. Despite a steady reduction of 54% in the carbon intensity of electricity between 1990 and 2020, the emissions trajectory of the EU needs an additional average annual rate decline of 3.5% to be on track with the Paris Agreement (International Energy Agency 2021).

As main GHG sources are fossil fuel power plants, decarbonization of the electricity sector in Europe is primarily determined by technology choices (Aalbers, Shestalova, and Kocsis 2013). In this context, gas has long been advocated to replace coal to produce electricity because of its lower carbon content (Delarue and D'haeseleer 2008; Wilson and Staffell 2018). Consistently, in 2020, gas power plants emissions overtook the ones from coal power plants[2]. However, in late 2021 and 2022, several factors coincided to provoke record gas prices in Europe. Invasion of Ukraine also strongly aggravated tensions on the European gas midstream sector, which is dependent for half of its imports on Russia[3]. In light of these events, the credibility of fossil gas as a transition fuel vanishes and Member States re-examined their long-term energy strategy.

In this context, Variable Renewable Energies (VRE) lie at the core of the European strategy. Ambitious objectives have been set in concert with the European Commission to reach net zero emissions by 2050. Yet, power generation of VRE is not fully controllable and critically dependent on meteorological conditions. This impossibility to shift their power output appears as one of the main limitations to their adoption. The growth of VRE technologies within the EU generation mix indeed reduces dispatchability and predictability and threatens reliability of the power system (Shafiullah et al. 2013). Despite a significant substitution

[1] Eurostat data on air emissions accounts by economic activity from 2011 to 2020.
[2] https://ec.europa.eu/clima/ets
[3] Eurostat, 48.4% for the first semester of 2021.

of fossil fuels by solar and hydropower in Europe, dispatchable assets, including natural gas, are needed to back up VRE (Marques, Fuinhas, and Pereira 2019). Globally, over the past fifty years, each unit of electricity generated by non-fossil-fuel sources displaced less than one-tenth of a unit of fossil fuel-generated electricity (York 2012). Excluding fossil fuels from power generation will require complementary solutions than expanding VRE, including adapting the power infrastructure and implementing more flexibility options (Corsatea et al. 2016).

Among the flexibility solutions listed by the International Energy Agency (2008), electricity storage has become increasingly interesting because of its versatility and recent high costs reductions (BloombergNEF 2021). More specifically, battery and power-to-fuel have witnessed massive R&D investments from the automotive sector. Large-scale storage could ensure multiple services on the European power systems, notably smoothing the intermittent production, alleviating the costs of support policies towards VRE, but also evicting carbon-intensive power plants. In the last years, the increasing volatility on the wholesale market signaled the importance of back-up units to balance the VRE production (Ketterer 2014; Clò, Cataldi, and Zoppoli 2015; Wozabal, Graf, and Hirschmann 2015). Furthermore, many European countries have committed to phasing-out coal power plants. This will naturally widen the flexibility needs in Europe and progressively lead to a situation more propitious than ever before for storage.

However, storage has ambiguous effects on GHG emissions (Carson and Novan 2013; Linn and Shih 2019). It can be environmentally detrimental depending on the emission rate of power producers it charges from and replaces when releasing energy. This effect is amplified because of energy losses during the storing process. Overall, storage is a net energy consumer and its use requires additional power generation, generally from carbon-intensive sources. Finally, by altering the dispatch, storage impairs the efficiency of flexible thermal plants (Graf and Marcantonini 2017), but also modifies the structure of the revenues among market participants and their long-term investments, which can lead to higher emissions (Bistline and Young 2020). Therefore, we investigate in this paper the development potential of energy storage solutions and their impact as future dispatchable assets to compete with existing and future fossil fuel power plants. We put the effects of storage on other power markets participants at the core of our analysis. Economic viability of storage could result in a partial eviction of carbon-intensive fossil fuel power plants, hence improving Europe's energy independence and reducing its CO_2 emissions. Additionally, understanding the influence storage operates on the power system and the wholesale market is of critical importance to adequately define the support levels towards VRE. Failing in doing so could result in inefficient economic allocation and wasted time to reach climate neutrality for the power sector.

Our work relates to a broad and flourishing literature dealing with storage in the energy transition. For historical reasons, pumped-hydro storage (PHS) represents as of today the main energy storage solution in Europe. With huge rating capacities, mature and amortized PHS plants stemming from former natural monopolies formed an interesting benchmark. Economic literature largely focused on the possibility to exploit a dominant position in flexibility services with Borenstein and Bushnell (1999),Dudine, Hendel, and Lizzeri (2006), Sioshansi (2010) and Mitraille and Thille (2014) and Child et al. (2019).

In a fast growing renewable context, an obvious service provided by storage could be reducing the negative effects of intermittency on the grid and helping the integration of VRE systems. Using a technical framework, Weitemeyer et al. (2015) estimate the need for storage in Germany depending on the penetration of VRE. They find that utility-scale storage devices really become necessary when more than 80% of the electricity demand can be met by wind and solar energy. Berrada and Loudiyi (2016) and Qi, Liang, and Shen (2015) and Braff, Mueller, and Trancik (2016) include economic considerations in their methodologies for determining the optimal operation and sizing of energy storage systems in association with wind and solar farms. With a more theoretical perspective, Pommeret and Schubert (2019) study the influence of the matching of solar production with the consumers' preference on the optimal size of a costless but imperfect storage technology.

On top of balancing VRE sources, storage systems can level the load by arbitraging electricity prices on the day-ahead and intraday markets, help smooth fluctuations on balancing markets, provide other ancillary grid services, reduce price volatility, and improve the quality of energy (Denholm et al. 2010). A broad part of the literature subsequently aims at determining the values of the multiple services provided by storage systems simultaneously. Byrne and Silva-Monroy (n.d.) and Drury, Denholm, and Sioshansi (2011) investigate the revenues of arbitrage and reserve services in the United States. Xi, Sioshansi, and Marano (2013) use a stochastic dynamic programming framework to evaluate arbitrage, back-up, regulation and distribution relief. Consistently in all three papers, arbitrage provides less value than regulation.

Despite being of crucial importance and increasing the understanding of storage revenues, this literature either assumes a sufficiently small capacity of storage such that it has no effect on the wholesale price, or introduces an exogenous storage capacity. We therefore identify two pitfalls in the current knowledge. First, few studies focus on the long-term equilibrium, which is better suited to appraise the market size for storage. The value of price arbitrage, among other services, is indeed limited and high amounts of storage capacity will eventually saturate markets, making them to collapse (Karaduman 2021). Steffen and Weber (2013) develop a capacity planning model to estimate the optimal size of storage in Germany in the near future but implicitly neglect the inter-temporal constraints using load duration curves. Ambec and Crampes (2019) and Schmalensee (2019) propose analytical models, which, among other insightful results, derive the equilibrium market size for storage. Yet, such approaches are inoperable to deduce quantitative values for specific case studies. Linn and Shih (2019) investigate to what extent dropping storage costs can help reduce GHG emissions through analytical and numerical models. They evaluate the equilibrium outcomes under different costs and policies scenarios, but keep a deterministic framework and do not account for the competition of new fossil fuel power plants. Finally, an abundant literature has flourished around the redesigning of the entire power system in the long run (Sisternes, Jenkins, and Botterud 2016), generally with 100% renewable, accounting for storage solutions, but do not emphasis on the transition (Heide et al. 2011; Rasmussen, Andresen, and Greiner 2012; Steinke, Wolfrum, and Hoffmann 2013; Bussar et al. 2016; Gils et al. 2017; Child et al. 2019).

Second, short-term or marginal rationale prevent from properly assessing the effect of large scale storage on price and the consequences on new power investments. In particular, peaking power plants could suffer from the competition of new storage even though they are already relegated to restricted operating hours with the growth of renewables. Solar cannibalization could also be limited by supporting prices in the middle of the day, but oppositely, wind firms could earn less from peak hours. All these questions remain largely unanswered in the current literature and our work aims at filling this gap.

Our contribution to the existing literature is fourfold. First, we estimate the energy-only market-based development potential of new storage systems. Our approach does consider several promising technologies (hydrogen, batteries and electric vehicles) and a time horizon of 20 years towards the target of net zero emissions. Despite our work not dynamically representing a pathway until 2040, we provide insightful results on the transition during this period. Contrary to many articles, we derive long-term equilibria, which endogenously compare the aggregate value of energy storage and the associated costs of investments. Secondly, we take on the importance of considering the current situation to provide the best estimates. Estimations of the future storage installations in a specific area are narrowly related to its renewable and consumption trajectories. Yet, the market size of storage is of utmost importance to properly evaluate the subsequent effects on the power sector. Our model is actually calibrated on the Western European power system and includes a large

10-country integrated area, to allow for a country-level comparison. Our work use a fine modelling of the existing flexibility park, including PHS and nuclear availability, and relies on an exhaustive, heterogeneous and fully parameterized unit-level representation of existing power plants. Such effort allows to depict more realistic price structures with and without new storage facilities. Thirdly, we are among the first to deeply investigate the competition between fossil fuel power plants and new storage technologies, and present the latter as new incomers that could challenge the incumbents positions. We propose a novel analysis in the light of the recent energy and geopolitical crisis, which might help the understanding of where Europe stands today in its path towards energy independence. Finally, we provide a rich framework to analyse the influence of storage on new investments in VRE and efficient gas power plants. Using a stochastic model, we account for a multitude of meteorological and consumption scenarios, which render robust results for the consideration of VRE economic viability and the design of an adequate public support scheme.

The structure of the paper is as follows. Section 2 introduces a theoretical model to better understand the effect of large-scale storage on the wholesale price. Section 3 describes the stochastic two-stage model we use to estimate the European market size of storage until 2040 and to quantify the projected impact on market participants. The results are discussed in Section 4. Section 5 draws the takeaways and concludes.

2 The impact of storage in a stylized model

In this section, we consider a stylized model to derive insights on how a generic storage technology interacts with the power market and its participants. In particular, we highlight the difference between short-term and long-term conclusions. Storage supports the development of solar power but has ambiguous effects on wind power. We underline that effects on CO_2 emissions is case-dependent and identify supply curve convexity as one important determinant for the impact of storage.

Equilibrium without storage

In the same vein as Sioshansi (2010), Carson and Novan (2013) or Linn and Shih (2019), we consider a two-period model. Period 1 corresponds to an off-peak period and period 2 to a peak period. Therefore, residual demand D_i^r for electricity is lower in period 1 than in period 2. To be specific, demand D_i is supposed inelastic and we assume $D_2 \geq D_1$. As for renewables, capacities $\overline{Q_{wind}}$ and $\overline{Q_{solar}}$ are available. For simplicity, we assume that wind produces on average as much in off-peak and peak periods and solar produces only in off-peak period[4]. This ensures renewable production remains greater on average in off-peak period than in peak period and that storage is useful to balance the mismatch with demand. More precisely, wind and solar are producing at full capacity, at a zero marginal cost, respectively with a probability p_{wind} and p_{solar}, otherwise, production is zero.

To balance VRE, we consider two conventional technologies, a base-load technology A and a peak one B. Technology $j \in \{A, B\}$ exhibits an emission rate e_j. Every market participant is price-taker. We denote by $P = S^{-1}(Q)$ the inverse aggregate supply function considering no renewable production. This merit-order is supposed piece-wise-linear as in Figure 1:

$$S^{-1}(Q) = \begin{cases} \alpha_A.Q + \beta_A & \text{if } 0 \leq Q \leq \overline{Q^A} \\ \alpha_B.(Q - \overline{Q^A}) + \beta_B & \text{if } \overline{Q^A} < Q \leq \overline{Q^B} \end{cases} \tag{1}$$

$$\text{with } \beta_B = \alpha_A.\overline{Q^A} + \beta_A$$

[4] In Europe, peak periods happen around 9am and 7pm , typically when solar is almost not available. Very little difference can be observed for wind power, which tends to produce slightly more during the middle of the day.

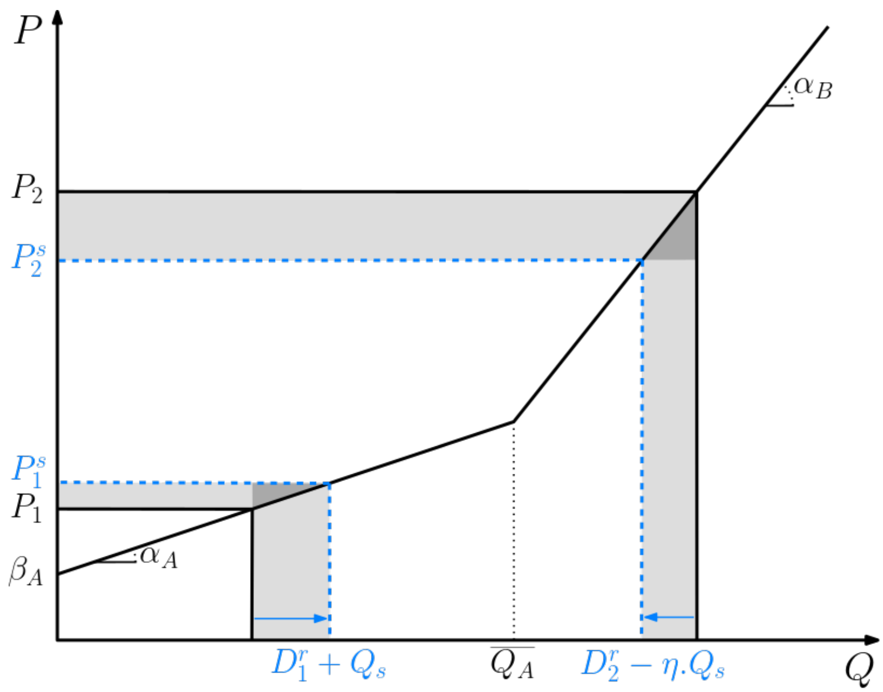


Figure 1: Impact of storage on the prices of periods 1 and 2

If $\mathbb{E}[.]$ corresponds to the expectancy operator, equilibriums read:

$$\mathbb{E}[P_1] = \alpha_A.(D_1 - p_{wind}.\overline{Q_{wind}} - p_{solar}.\overline{Q_{solar}}) + \beta_A \tag{2}$$

$$\mathbb{E}[P_2] = \alpha_B.(D_2 - p_{wind}.\overline{Q_{wind}} - \overline{Q^A}) + \beta_B \tag{3}$$

Short-term equilibrium with storage

We first introduce a limited quantity Q_s of storage on the market, with a round-trip efficiency $\eta \in [0, 1]$. Storage arbitrages prices by applying a "buy low – sell high" rule. Hence, it increases the demand by Q_s while charging in off-peak period 1 and the supply by $\eta.Q_s$ while releasing in peak period 2:

$$\mathbb{E}[P_1^s] = \mathbb{E}[P_1] + \alpha_A.Q_s \tag{4}$$

$$\mathbb{E}[P_2^s] = \mathbb{E}[P_2] - \alpha_B.\eta.Q_s \tag{5}$$

Proposition 1 *Storage reduces the spread between the two periods by* $(\alpha_A + \alpha_B.\eta).Q_s$.

Assuming the unitary cost for operating storage over two periods is k_s, the expected profit reads:

$$\mathbb{E}[\Pi_s] = Q_s.\big(\eta.\mathbb{E}[P_2^s] - \mathbb{E}[P_1^s] - k_s\big) \tag{6}$$

Other things being equal, the zero profit condition yields the long-term capacity of storage:

$$Q_s^* = \frac{\eta.\mathbb{E}[P_2] - \mathbb{E}[P_1] - k_s}{\alpha_A + \alpha_B.\eta^2} \tag{7}$$

Proposition 2 *Storage appears on the power market if:*

$$\frac{1}{2}\Bigg((1+\eta).\mathbb{E}[P_2 - P_1] - (1-\eta).\mathbb{E}[P_1 + P_2]\Bigg) \geq k_s \tag{8}$$

Two remarks can be done regarding Proposition 2. First, we observe that contrary to a common belief, price spread $\mathbb{E}[P_2 - P_1]$ is not the only driver of the storage market size, as price level $\frac{\mathbb{E}[P_1 + P_2]}{2}$ also contributes. The higher the wholesale price, the more expensive are the losses due to inefficiency, whatever the volatility. This has a major implication for low efficiency technologies such as hydrogen, that would benefit more from lower price levels than efficient batteries for instance. Importantly, the influence of each driver depends on the round-trip efficiency. Second, we observe from Equation 7 that the less elastic supply is to prices, the more profitable it is to develop storage. Hence, steep merit-order curves shrinks storage penetration.

Proposition 3 *CO_2 emissions shift linearly with the storage capacity, and more precisely:*

$$\frac{\partial E_{CO_2}}{\partial Q_s} = e_A - \eta.e_B \tag{9}$$

If technology A is more carbon-intensive than technology B, emissions increase with the presence of storage. Else, storage increases CO_2 *emissions in the short term only if* $\frac{e_A}{e_B} \geq \eta$.

Proposition 3 implies that in the case of high gas prices relative to coal, storage penetration might increase the CO_2 emissions. This phenomenon has already been observed by Carson and Novan (2013) and Graff Zivin, Kotchen, and Mansur (2014). However, even in the case where gas is used as a base-load technology, storage must be sufficiently efficient in order to prevent additional emissions because of energy losses in the storing process. Assuming roughly 820 gCO_2/kWh for coal and 490 gCO_2/kWh for gas (Schlömer et al. 2014), whatever storage technology with an efficiency lying below 60% will participate to higher CO_2 emissions. This has major implications for old PHS or new power-to-gas technologies which exhibit high round-trip losses.

Because of the effect of storage on the price structure, the changes in revenues for VRE technologies read:

$$\Delta R_{solar} = \mathbb{E}[Q^{solar}.(P_1^s - P_1)] = p_{solar}.\overline{Q^{solar}}.\alpha_A.Q_s \geq 0 \tag{10}$$

$$\Delta R_{wind} = \mathbb{E}[Q^{wind}.(P_1^s + P_2^s - P_1 - P_2)] = p_{wind}.\overline{Q^{wind}}.(\alpha_A - \alpha_B.\eta).Q_s \tag{11}$$

Proposition 4 *In the short term, storage sustains the most intermittent VRE technology, solar, by supporting prices in off-peak period ($\Delta R_{solar} \geq 0$).*

By denoting, $C = \frac{\alpha_A}{\alpha_B}$ the concavity index[5] *of S^{-1}, wind is better off with storage only if $C \geq \eta$. If S^{-1} is highly convex, $C \leq \eta$, the price drop in the peak period is not compensated by the price increase in the off-peak period, and storage is detrimental to existing wind firms.*

Furthermore, if $C \geq \eta$, there exists a thermal capacity threshold Q_0, which separates positively

[5] $C \geq 1$ indicates a concave curve and $C \leq 1$ a convex curve.

affected conventional power plants from negatively affected ones. This threshold reads:

$$Q_0 = D_1^r + \left(1 - \frac{\eta}{C}\right).Q_s \tag{12}$$

Figure 2 illustrates the last point of Proposition 4 and shows that power plants are unequally affected. We display the change in revenues depending on the ranking in the merit-order. Least costly and firstly dispatched power plants lie on the left. These plants, which produce in both periods, are positively affected by storage in a similar fashion as wind power. Conversely, plants which are solely producing in the peak period experience a drop in their revenues that is not compensated. Storage tends to evict high marginal costs power plants located above the break-even capacity Q_0 but generates windfall profits for the others.

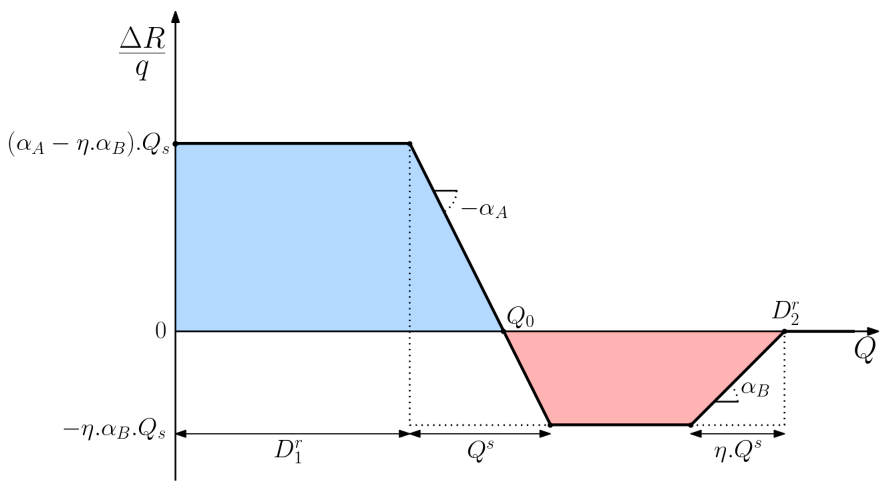


Figure 2: Change in producers' revenues depending on the ranking in the merit-order. The red area represents a drop in revenues, whereas the blue area represents an increase.

Long-term equilibrium with storage

In the long run, the changes induced by storage on the price structure can evict existing firms or trigger investments in new assets. We suppose that new solar (Q^+_{solar}) and wind (Q^+_{wind}) capacities can be installed respectively at amortized capital cost k_{solar} and k_{wind} for the two periods.

Proposition 5 *(Proof in Appendix A) Each storage unit entering the market triggers in the long term the investment in:*

$$\frac{\partial Q^{**}_{solar}}{\partial Q_s} = \frac{1 + \eta.p_{wind} + C.(1 - p_{wind})}{1 + C.(1 - p_{wind}.p_{solar})} \geq 0 \tag{13}$$

$$\frac{\partial Q^{**}_{wind}}{\partial Q_s} = \frac{C.(1 - p_{solar}) - \eta}{1 + C.(1 - p_{wind}.p_{solar})} \tag{14}$$

Furthermore, we have:

$$\frac{\partial Q^{**}_{wind}}{\partial Q_s} \geq 0 \Longleftrightarrow C \geq \frac{\eta}{1 - p_{solar}} \tag{15}$$

In all cases, storage helps the development of solar. Indeed, the balancing effect of storage supports the most fluctuating source. Conversely, more investment in solar facilities drags the off-peak price down and creates a favorable situation for storage. The development of solar and storage is therefore mutual. The effect of storage on wind power however is ambiguous. Three drivers can be identified for a reciprocal development of storage and wind: if the merit order is highly concave ($C \gg 1$), if the solar resource is very limited ($p_{solar} \ll 1$) or if storage is very inefficient ($\eta \ll 1$).

Long-term equilibrium with storage and new thermal capacities

We finally allow for new thermal capacities to enter the market. Given the previous results illustrated by Figure 2, base-load units are more needed and we denote the amortized cost k_A. Entering firms are supposed identical, fully dispatchable and exhibit a marginal cost β_A, so that they are less costly than their older counterparts.

Proposition 6 *(Proof in Appendix A) Each storage unit entering the market triggers in the long term the investment in:*

$$\frac{\partial Q^{***}_{solar}}{\partial Q_s} = \frac{1 + \eta}{1 + C.(1 - p_{solar})} \geq 0 \tag{16}$$

$$\frac{\partial Q^{***}_{wind}}{\partial Q_s} = 0 \tag{17}$$

$$\frac{\partial Q^{***}_{A}}{\partial Q_s} = \frac{C.(1 - p_{solar}) - \eta}{1 + C.(1 - p_{solar})} \tag{18}$$

One can notice the similarity of Proposition 5 and Proposition 6, where wind is replaced by a fully available source ($p_{wind} = 1$). Importantly, storage still supports the solar technology but has no impact on wind anymore, which settles at a constant value depending on the relative investment costs. Furthermore, the relation between new thermal capacity and storage can be both ways. Therefore, if new thermal capacity is available, it directly hinders the mutual development of wind and storage, and possibly of solar and storage.

Proposition 7 *(Proof in Appendix A) In the long term with additional base-load capacities, there exists a concavity index C_0 such that storage reduces emissions:*

- *If $e_B \geq \frac{2}{\eta+1} e_A$ and $C \geq C_0$*
- *Or $e_B \leq \frac{2}{\eta+1} e_A$ and $p_{solar} \geq \frac{1-\eta}{1+\eta}$ and $C \leq C_0$*

A noteworthy remark from Proposition 7 is that a low-carbon base-load technology is an important driver of the ability for storage to participate in emissions reduction. The lower e_A, the less likely storage increases emissions, provided that the base-load technology is sometimes marginal to allow for supplementary production. A high price of CO_2 can help ensure that the base-load technology is the least carbon-intensive one. However, this condition is not sufficient as it must offset the round-trip losses of storage and the potential disinvestment in wind power. Such a result implies that storage is a moderately effective solution to curb emissions without great solar potential, a high CO_2 price or the existence of a low-carbon base-load technology. As a corollary, high CO_2 prices might have little effects in association with storage, as long as the emission rate heterogeneity among conventional plants is narrow, like in a one-technology dominated market.

The theoretical model demonstrates that the consequences of storage penetration cannot solely be evaluated from a short-term point of view. Because of the effect on VRE investments, storage has an equivocal impact on CO_2 emissions. We highlight the pivotal role of the shape of the supply curve and the matching of VRE production with demand. Further empirical investigations on various case studies must be conducted to conclude whether storage is environmentally beneficial.

3 A quantitative power model for Europe

To better quantify the investments generated by power markets in new gas or storage and to dispel their ambiguous impact on CO_2 emissions and renewables, we propose an empirical model representing the current Western European electricity power system. We simulate a simplified version of the future grid until 2040, including ten of the most important countries[6].

3.1 Stochasticity and scenarios

Zakaria et al. (2020) put the emphasis on the fact that optimization of renewable energy systems can only be accurately solved if uncertainties and fluctuating behaviours of renewable energy systems are properly represented. Deterministic methods can produce idealistic results and fail to capture the dynamics of modern energy systems (Abdmouleh et al. 2017). Thus, the characteristics of stochastic optimization methods are more suitable in handling the intermittent nature of renewable-based power sectors. We follow Conejo, Carrión, and Morales (2010) and use a stochastic approach with scenarios, which are supposed to faithfully represent the fundamental discrepancies between seasons and the various states of the power system.

Annual simulations are computationally costly and it is a cumbersome task to combine them

[6] France, the United Kingdom, Portugal, Spain, Italy, Switzerland, Austria, Germany, Belgium and the Netherlands.

with a stochastic framework (Aien, Rashidinejad, and Fotuhi-Firuzabad 2014). Instead, we follow Alimou et al. (2020), by considering the shortest consistent pattern for scenarios being one-week long. Such choice necessarily belittles the importance and the role of PHS storage systems and to some extent, power-to-gas solutions. However, alternations between weekends and weekdays is fully accounted. Accordingly, we build fictional but realistic one-week scenarios, aiming at accurately representing the possible states of the European power system. Data used for creating scenarios primarily originate from two sources, the ENTSOE Transparency platform, which contains a full range of disaggregated information on the power systems on top of historic production and consumption data[7] as reported by the national system operators, and Renewables Ninja (Pfenninger and Staffell 2016; Staffell and Pfenninger 2016), which is a well-known country-level database and provides estimates of hourly VRE capacity factors since 1980 [8].

To keep consistent patterns, the year is divided in six seasons of two consecutive months each. The sampling process, illustrated in Figure 3, is similar to a Monte-Carlo method and randomly picks one-week realizations from the historical data from the same season. For each country, electricity consumption, and VRE capacity factors are sampled over 168 hours. We describe the state of the power system with two additional variables derived from the Transparency platform, availability of a national nuclear park because of maintenance, and water inflows, which correspond to the amount of costless energy that is at the disposal of flexible hydro plants, due to rainfalls and upstream water.

[7] We restrain the data to the years 2015-2019 to keep only the recent features of the power system and to preclude the Covid-19 period and the following energy crisis.
[8] Capacity factor is defined as the ratio of production to installed capacity and allows the scalibility to different renewable park sizes assuming constant returns.

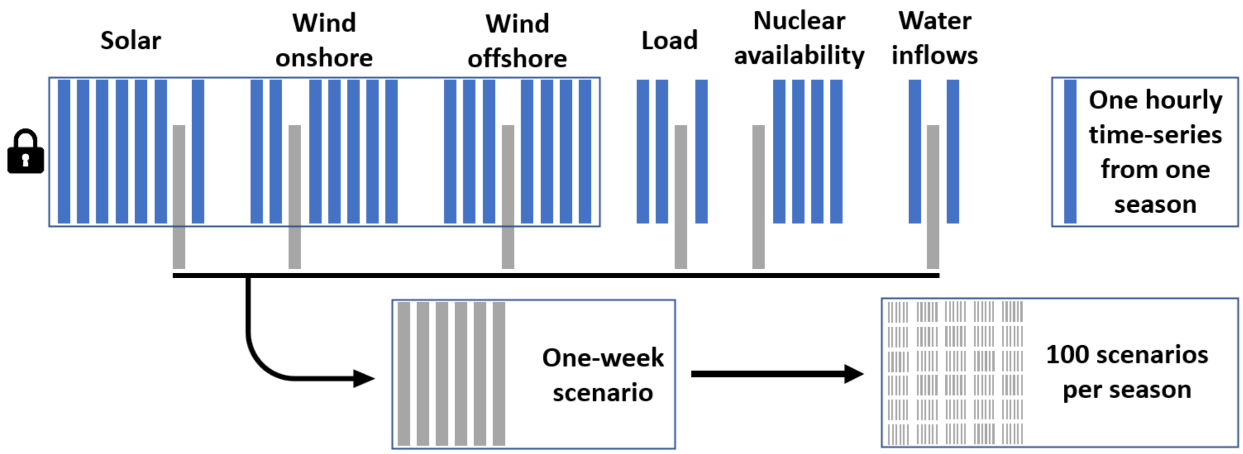


Figure 3: Scenario sampling process. The lock pictogram indicates a simultaneous sampling to preserve correlation between the time series.

Because of spatial and temporal correlations between countries and variables, sampling can occur simultaneously. For instance, as onshore wind, offshore wind and solar time series might be correlated, scenarios are built with the same week for these three variables and for all the countries. Same goes for electricity consumption which is correlated between countries.

100 independent scenarios are extracted from the data per season, which amounts to a total of 600 weekly scenarios. This corresponds to approximately 11.5 years of operation. Such number is determined based on the count of unique weeks in the sampling data and so that it approximately represents an entire lifetime for battery storage technology (10 years).

3.2 Modelling the current and future power system

Consumption

Because of electrification policies, we assume a 1% increase per year of the electricity consumption in all countries until 2040. This excludes additional consumption due to the market base broadening of electric vehicles, which is treated later in the section. The consumption structure, however, remains identical as we use historical data. Including consumption from

EVs, the average annual growth rate for electricity consumption ranges from 1.44% for Belgium to 1.92% for Portugal.

Hydropower

The expansion of the current flexible hydro park has been largely studied in the literature. Lako et al. (2003) and Rogeau, Girard, and Kariniotakis (2017) and Quaranta et al. (2021) all conclude that the extension of the current hydro storage capacity lies between 8% and 18% in Europe. Yet, this limited potential is derived from technical perspectives and not economic ones. Given that investments costs are very project-dependent, the expansion of the European hydro park is uncertain. We consequently opt for a conservative assumption that the park remains as is until 2040.

Interconnections

The ten countries of the model are all interconnected based on the border exchange capacity from ENTSOE (2019). To take into account reinforcement and future changes of the European grid, we also consider border capacity increases based on the Ten-Year Network Development Plan 2022 (ENTSOE 2022). The TYNDP anticipates an additional 24 GW of interconnections capacity between the countries of interest in our study by 2030 and 37 GW by 2040 (respectively +30% and +45% compared to 2019).

Renewable capacities

Renewable installations are partially determined by political support schemes and partially by market mechanisms Newbery et al. (2018). Finely modelling the techno-economics and the renewable deposits of each country to allow for purely endogenous renewable capacity determination would happen to be a tedious work. Instead, we adopt an intermediary approach, by considering the future renewable capacities aligned with the EU targets. We use the National Energy Climate Plans[9] (NECP) as baselines. These documents have been

[9] EC Europa

drafted by the Member States to the European Commission and trace the national commitments towards net zero emissions for the 2021-2030 period. From these baselines that implicitly include the national levels of support and the available resources, we define a corridor in which VRE can develop (±50% of the NECP target). We endogeneize realistic VRE capacities that derive from market conditions based on the characteristics of Appendix B.

Storage options

Luo et al. (2014) provide a comprehensive picture of available storage technologies, and where they would be suited for integration into a power generation and distribution system. Following their conclusions, we retain 4 different storage technologies based on their readiness and commercial experience: PHS, Li-ion stationary battery, Li-ion vehicle-to-grid (V2G) and power-to-hydrogen (see Table 1). V2G essentially differs from EVs by their ability not only to charge from the grid, but also to release power back to the grid.

Technology	**Pumped hydro**	**V2G (Li-ion)**	**Battery (Li-ion)**	**Power-to-hydrogen**
Charging efficiency (%)	86.6	93	93	60
Discharging efficiency (%)	86.6	93	93	60
Storage costs (€/kWh)			211	5
Charging capacity costs (€/kW)			137	1 463
Discharging capacity costs (€/kW)		55		1 215
Lifetime (years)		10	10	25
Annual learning rate (%)		1.0	3.5	3.5

Table 1: Storage parameters (BloombergNEF 2021)

Modelling the fleet of electric vehicles

Electric vehicles represent an important change for the grid in the sense that they progressively increase electricity demand and may act as a flexibility option if converted into V2G. Similarly to stationary storage, we model the national fleets as one storage system that responds to the wholesale price signal. The charging capacity depends on the instantaneous share of parked vehicles, while the discharging capacity depends on the share of V2G within the fleet. What differs for vehicles compared to stationary storage is first that we account for an energy leak representing the driving patterns and second that the state of charge should never lie below 50%. This value is consistent with Azadfar, Sreeram, and Harries (2015), who observe owners plug their vehicles before running low on energy, disregarding the cost of electricity.

Pasaoglu et al. (2014) provide the patterns for European car drivers derived from a mobility survey. The study includes five countries of our own set, notably France, Germany, Italy, Spain and the United Kingdom. We extracted a realistic hourly probability of driving and derived the instantaneous expected consumption of the fleet, considering as a reference single car model, a medium electric hatchback[10].

Regarding the size of national EV fleets, we suppose it grows linearly and that by 2035, 30% of the total fleet would be electrified. The national fleet sizes are taken from European Commission and Transport (2021) and supposed constant over time. Finally, costs of transforming electric vehicles into fully revertible vehicle-to-grid assets providing flexibility to the grid is set according to Huber et al. (2021) (see Table 1).

Conventional capacity

The electricity mixes are derived from per-unit generation data of the Transparency platform. This dataset is a complete generation dispatching, hour by hour, for the most important power plants. Between 2017 and 2019, 731 plants have been active in the 10 countries of interest. We cross this dispatching data with the JRC Open Power Plants Database

[10] Consumption is set at 0.16 kWh/km, storage capacity at 50 kWh and power rating of charging station at 5 kW on average.

(Kanellopoulos et al. 2019), which contains exhaustive information on the technology, the CO_2 emission rate and the efficiency of each power unit in Europe.

Regarding the expansion of thermal capacity, mandates have been announced by the Member States to phase out coal from the power sector (Europe Beyond Coal 2021). By 2025, France, the United Kingdom and Italy are expected to become coal-free, while the Netherlands, Germany and Spain have committed to later targets. Decommissioning coal-fired peaking power plants might require a substitution to maintain the balance between electricity demand and production. If reliable trends can be observed, the near-term future of the generation mix is still undecided and subject to political decisions. We cover two possible outcomes, a coal phase-out with a substitution by new storage and gas power plants on the one hand, and on the other hand a coal-phase-out without relying on new gas facilities at all. The techno-economic parameters of new gas are detailed in Appendix B. In particular, regular gas turbines (GT) and modern combined cycle gas turbine (CCGT) are available, but new gas capacities should not exceed what has been phased-out.

Price of $\mathbf{CO_2}$

The price of CO_2 is determined by applying Hotelling's rule (Hotelling 1931). From a 2022 price around 80 €/tCO_2 in average, we apply a 5% discount rate to derive the CO_2 pricing trajectory. By 2040, the price reaches 200 €. We provide some sensitivity results, including a higher trajectory for this price among others in Appendix Appendix C.

3.3 Optimization programs

The problem can be formulated as a minimization of the total cost of the power system:

$$\min_{\overline{X}} \mathbb{E}\left[\min_{Z_{\zeta,t}} \sum_{t=0}^{T} \left(\sum_{j\in\mathcal{J}} y_{j,\zeta,t}.MC_j + \sum_{c\in\mathcal{C}} V_c.LL_{c,\zeta,t}\right) + C\left(\overline{X}\right)\right] \tag{19}$$

where $\overline{X}$ denotes the investment variables in storage, gas and VRE facilities, which cost $C(\overline{X})$, and $Z_{\zeta,t}$ the operational decisions, including the conventional production $y_{j,\zeta,t}$ at marginal cost MC_j and the quantities of unsupplied energy (lost load) $LL_{c,\zeta,t}$, valued at V_c for each country. We break down each agent's program for clarity in Appendix D.

Due to the stochastic approach, the problem is particularly large. We exploit its linear structure and solve it as a two-stage program using a multi-cut Benders decomposition (Benders 1962), with a convergence criterion set at 10 € to ensure accurate values for optimal investment decisions.

3.4 Calibration

For the model to reproduce the right dispatch and signal the proper prices to drive investments, we perform an accurate tuning of the economic parameters. The first step of the calibration makes use of the actual hourly dispatch data to determine a national ranking of power plants based on the average price they have received for their production between 2017 and 2019. We assume this price is the spot price as given by the day-ahead market clearing. We introduce heterogeneity among the same technology by defining the marginal cost by power plant j, which takes the following form:

$$MC_j = c_j^v + p_{CO_2}.e_j + \frac{p_{fuel(j)}}{\eta_j} \tag{20}$$

where c_j^v is the fixed component of the variable cost, p_{CO_2} is the average price of CO_2 as given by the EU-ETS data, $p_{fuel(j)}$ is the average fuel price (either coal, gas or oil), e_j is the emission rate of power plant j (in tCO_2/MWh) and η_j is its thermal efficiency.

The second step consists in repeatedly running the complete model to adjust c_j^v until it reproduces the observed prices in Europe in 2019[11]. For each run of the model, we extract

[11] It is the most recent year before the pandemic and the energy crisis disrupted the power markets.

the periods when a power plants is marginal. We calculate the output price of the model and compare it with the actual spot price. We finally perform a minimization of the ℓ^2-distance between the model's output prices and the day-ahead prices, while imposing no change in the initial ranking of power plants. For power plants that never happen to be marginal, marginal cost is interpolated afterwards. A few runs are usually sufficient to converge towards satisfactory results (Table 2).

Country	FR	ES	PT	DE	BE	AT	UK	NL	IT	CH
$\mathbf{R}^2$	0.81	0.81	0.81	0.77	0.76	0.71	0.69	0.68	0.67	0.59

Table 2: R^2-scores of the calibration of the merit-order

The poorer results deserve some explanations. The Swiss mix is based on a few hydro and nuclear power plants, two technologies for which it is difficult to derive accurate marginal costs, as well as imports/exports, which play a substantial role in the country electricity supply. Other countries also suffer from the "edge-effect" as the model does not reproduce all their neighboring countries. On the other hand, border exchanges for France, Spain and Portugal are well represented. Overall, accounting for the fact the model is not able to produce low and negative prices, the R^2 are satisfactory.

4 Results and discussions

4.1 Storage capacities

The long-term equilibria for flexibility options under the two different cases are displayed on Figure 4, in green *With new gas* and in blue *Without new gas*. In the first case new flexibility is needed in the form of EV conversion into V2G. Combined with PHS systems and peaking power plants, these flexibility systems capture part of the value that would be needed for new stationary storage to reach profitability (battery and hydrogen are represented with hatched areas). From 2022 to 2029, phased-out coal capacity (red dotted line) is entirely replaced by new CCGT (green dashed line). This indicates that CCGT has an early competitive advantage and maintains low levels of investment into storage in most European countries. Uncoupling of phased-out coal and new gas occurs from 2030 and coincides with the progressive penetration of V2G. In particular, Spain and Portugal commit to sufficient VRE capacities that new gas is not required anymore to compensate for the coal phase-out and progressively abandoned. This simultaneously drives the market for V2G, which appear first in these two countries and reach 33 GW by 2040 (8% of EVs), with 10 GW for Spain alone (Figure 5a).

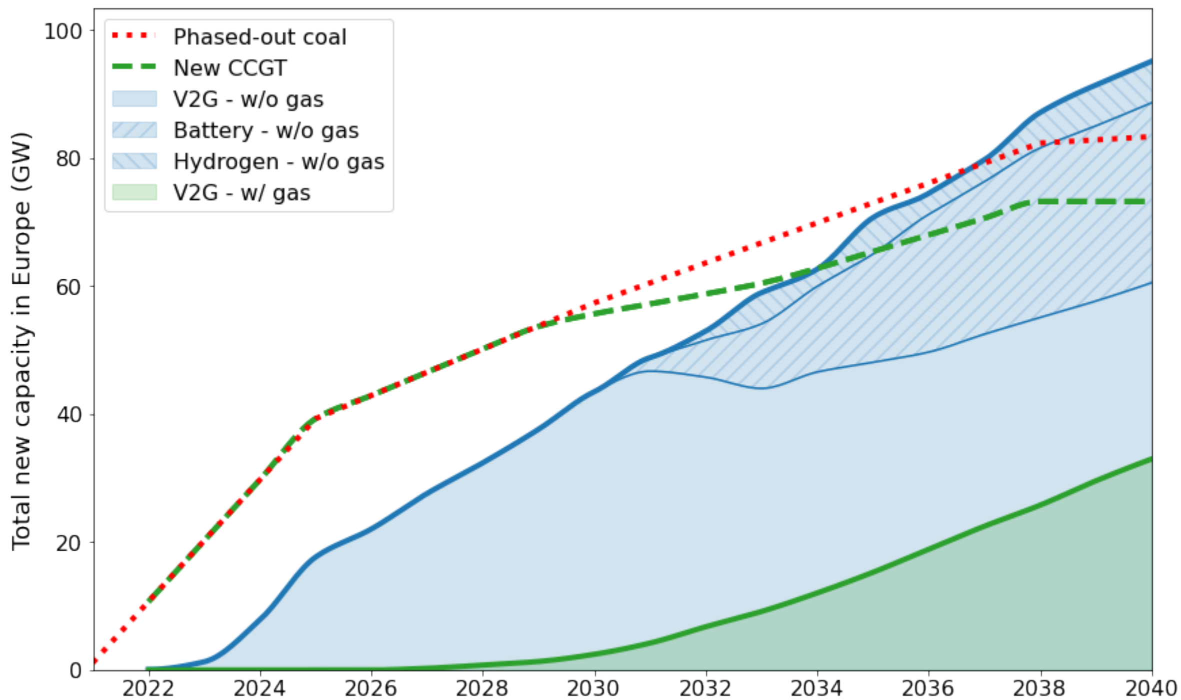
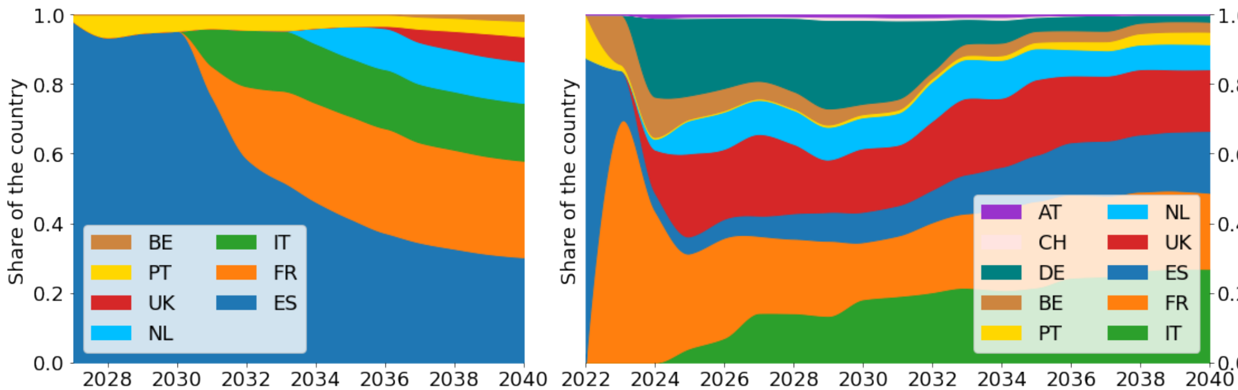


Figure 4: Cumulative capacity of flexibility options in Europe

When new gas is precluded, phased-out coal capacities are quickly replaced by new storage, the only possible mean to substitute flexibility (Figure 4). Market conditions trigger massive investments in V2G from 2025 with a regular trend until 2040, up to 60 GW. From 2030, battery storage enters the power market and amounts to 28 GW in 2040 (23 GW in Germany and 5 GW in the Netherlands), followed by power-to-hydrogen in 2032, which amounts to 5.5 GW in 2040 (2.5 GW in Germany, 2 GW in the United Kingdom and 1 GW in the

Netherlands). Comparison should be made with caution as for the same power rating, V2G provides less flexibility to the grid than stationary storage, and all-the-more less than dispatchable gas. V2G must indeed be parked and plugged-in with a sufficient state-of-charge to participate in grid services. In contrast, stationary storage is fully dedicated to commit in the most critical moments by responding to the price signal and adapts its charging and releasing periods accordingly.



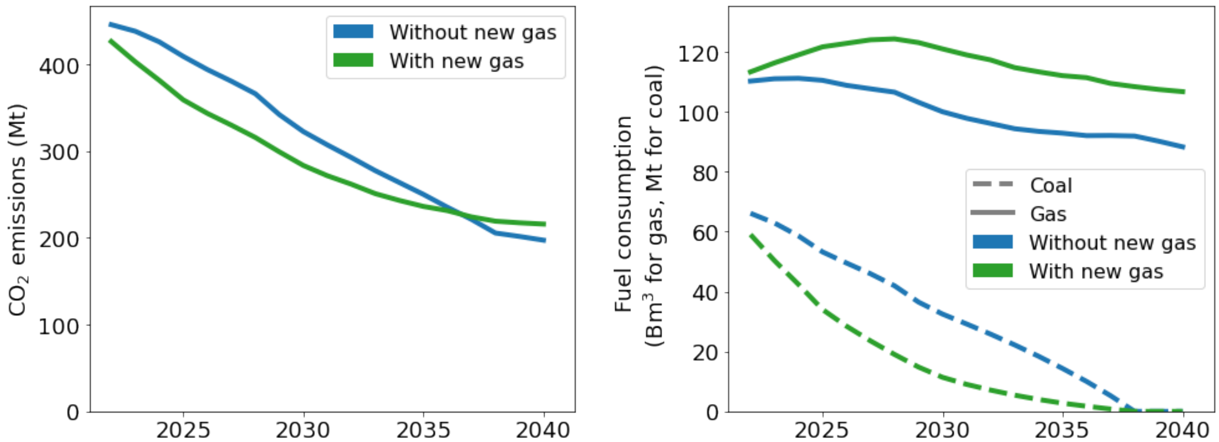
(a) With gas

(b) Without gas

Figure 5: Evolution of the share of the countries in the total V2G capacity

If focusing on the country-level V2G expansion, three classes of countries emerge. Switzerland, Austria, Portugal and Belgium almost do not draw on storage at all for their energy transition. Secondly, Italy, France and Spain exhibit a transition based on V2G, with around 20% of the total share whether gas is available or not. Finally, the United Kingdom, the Netherlands and most notably Germany belong to a group that heavily relies on new capacities. They prioritize new gas over storage if available, but otherwise depend first on V2G and then transition towards more flexible assets like battery and hydrogen. These three countries are therefore the most exposed to a coal phase-out policy.

4.2 Impact on the emissions



(a) CO_2 emissions

(b) Fuel consumption

Figure 6: Evolution of the annual CO_2 emissions and the fossil fuel consumption from the European power sector

Figure 6a draws the evolution of the total annual CO_2 emissions of the European power sector. From 2022 to 2040, CO_2 emissions regularly decrease by 56% reduction without gas and 49% with gas, roughly half of the way towards net zero by 2050 without compensation. Interestingly, the transition with gas is quicker until 2036, where emissions curves intersect and a storage-based transition achieves up to 19 Mt less per year. The faster pace of CO_2 reduction using new gas assets prevents 463 additional Mt, roughly sparing one year of emissions. The major insight lies in the ineffectiveness of storage to perform better in supporting a decarbonization pathway without a significant VRE penetration, as highlighted by the stronger emissions curbing with gas, despite a higher total cost of the system[12]. Yet, the slowdown at the end of the period of a gas-based transition calls for supplementary endeavors to keep reducing emissions. In the light of these results, given the current VRE targets and the future electricity consumption, a policy to restrict the construction of efficient gas power plants would be environmentally counterproductive in the short and medium term.

[12] The case without new gas is a constrained version of the cost minimization problem with gas and therefore incurs higher costs.

Figure 6b show how much natural gas and coal are necessary to balance the European power system for both pathways. Coal consumption falls rapidly when replaced by gas and becomes meaningless as early as 2033. One can notice a strong substitution for gas consumption, which tends first to increase and peaks in 2027. Conversely, storage allows a decrease of the gas consumption over the entire period but at the expense of a higher coal consumption, which largely explains the higher level of CO_2 emissions of this pathway. In all cases, a low-carbon transition remarkably builds on gas in the medium term. Nevertheless, around 20 Bm^3 less gas is consumed on an annual basis thanks to storage, ergo improving Europe's energy independence.

CO_2 intensity is used to compare situations among countries (left part of Table 3). National figures underline that new gas policies produce heterogeneous effects. Southern countries (Italy, Portugal, Spain) and Austria perform better if new gas is involved, contrary to Northern countries (Germany, the United Kingdom and Belgium). This geographical separation could find two possible explanations that need to be tested. The first rationale could be market integration, which implies that a significant disruption in Germany's generation mix propagates through border connections to its neighbors, who must compensate with higher production and emissions. The effort of phasing-coal would therefore be shared and new gas policies might be differentiate because of border exchanges. This view is partially supported by a powerflow analysis. Total European exchanges remain stable under both policies, with and without new gas, but Germany drastically reduces its net imports it the first case. This significantly benefits to Austria and Italy on one hand, and the United Kingdom through the Netherlands on the other hand, that all increase their net imports, supplied by new carbon-intensive German power plants. This explains the better achievements for Austria and Italy with new gas, and the worse for Germany. However, why Belgium and the United Kingdom still perform worse with higher imports is addressed next.

	CO_2 intensity			RE share		
New gas	w/o	w/o	w/	w/o	w/o	w/
Date	2022	2040	2040	2022	2040	2040
Germany	417	93	150	38	66	44
Netherlands	315	85	85	28	78	74
Italy	251	145	94	41	62	73
United Kingdom	188	66	82	30	70	59
Belgium	164	92	105	21	45	38
Austria	150	124	38	64	72	90
Portugal	121	29	18	67	92	95
Spain	114	36	34	50	81	81
France	44	14	14	21	50	46
Switzerland	0	0	0	40	54	54

Table 3: Evolution of CO_2 intensity (gCO_2/kWh)
and renewable share (%) between 2022 and 2040
Green figures represent the best case

4.3 Interaction between flexibility and VRE

A second rationale to clarify the North-South distinction lies in the different interaction storage and gas have with VRE technologies, as highlighted in Section 2. The Northern region largely relies on wind because of lower solar resources than in the Southern region. To qualify the differential support of gas and storage towards VRE, the renewable share in the national electricity production[13] was used. The right side of Table 3 compares the current metrics, as of 2022, and the predicted ones for 2040. Obviously, the renewable share is highly correlated with the CO_2 intensity. This demonstrates that evaluating the short-term effects of storage on CO_2 is biased because the main channel for storage to support

[13] Including hydro generation.

the transition arises through VRE. On top of powerflow reallocation, storage and renewable resource therefore play a pivotal role in CO_2 curbing.

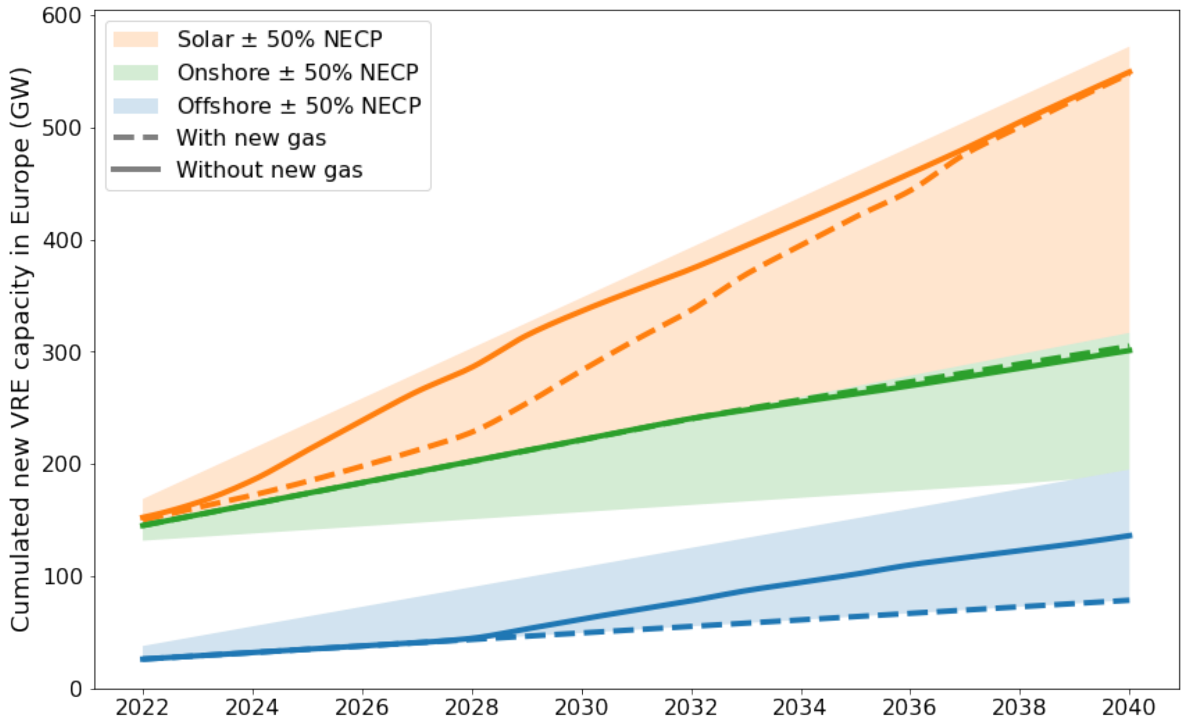


Figure 7: Development of VRE capacities with and without new gas

Simulations underline a much quicker development for solar when storage is the only new flexibility asset (Figure 7). The market driven investments in solar with storage lies 40% higher than the NECP reference path for the whole period. On the contrary, with new gas, the solar development is slower but finally catches up to 40% higher until 2040. These results support the theoretical conclusions that storage and solar are mutually beneficial. A soar of V2G capacities translates into a soar of solar, but this phenomenon is postponed to 2030 when new gas is available.

Building on Proposition 6, in presence of new gas, wind should moderately develop with storage because of the uncoupling. We observe consistent results as onshore and offshore growth is not supported by V2G arrival. Finally, we find that offshore wind development speeds up with storage in absence of new gas. By looking at national figures, Northern countries are more impacted than Spain or Portugal. It is therefore the condition 15 that allows the development of wind in countries where the solar load factor is much lower than the load factor of wind. It also contributes to differentiate policy effects on the Northern countries and the Southern ones. Interestingly, offshore wind generation seem to associate better with very flexible storage technologies as batteries and hydrogen, which is solely developed in Germany, the Netherlands and the United-Kingdom.

5 Conclusion

The literature generally presents energy storage as a suited mean to balance variable renewable energy sources and curb GHG emissions in the meantime. This literature often relies on firm-level analyses which do not account for the difficulties to generalize their results at a continental scale. Recent studies have shed light on ambiguous environmental consequences of the storage presence in the power markets in terms of GHG emissions. We contribute to addressing this issue by introducing a stylized model to illustrate the equivocal nature of the consequences of storage on the wholesale market. We highlight the importance of the shape of the merit-order and the mismatch of solar and wind production with demand. In a general case, solar and storage are mutually beneficial, whereas the relation with wind is case-dependent. New gas can also modify these results by delaying storage and shrinking the channel by which storage impacts VRE.

To quantify the possible outcomes, we test our theory using a stochastic cost-minimization numerical model, representing Western Europe as of today, and focus on a transition until 2040. We integrate a phase-out coal mandate policy, and evaluate the disruptions, with the substitution by new gas or new storage. We confirm the theoretical results by observing that all forms of storage help to reduce emissions indirectly through the support towards VRE. V2G appear suited to associate with solar, while hydrogen and batteries cope better with offshore wind fluctuations. However, their development and positive effects are delayed and limited because of the competitive advantage of new efficient gas power plants. This largely explains the better performance of new gas to reduce emissions before 2035. Yet, by 2040, a transition solely based on storage provides better environmental results and increases Europe energy independence. Our study consequently interrogates the future role of gas in the energy transition, and put the emphasis on policy considerations to promote innovation in storage, to prevent carbon-intensive sources from benefiting from a windfall effect and consequently to avoid a technology lock-in situation in Europe.

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Appendix A

Proof of Proposition 5

The zero profit conditions yield for the new capacities:

$$\begin{cases} \mathbb{E}\big[\big(P_1 + \alpha_A.(Q_s - Q^+_{solar} - Q^+_{wind}) - k_{solar}\big).Q^+_{solar}\big] = 0 \\ \mathbb{E}\big[\big(P_1 + \alpha_A.(Q_s - Q^+_{solar} - Q^+_{wind}) + P_2 - \alpha_B.(\eta.Q_s + Q^+_{wind}) - k_{wind}\big).Q^+_{wind}\big] = 0 \end{cases}$$

Revenues of solar (respectively wind) are positive only if solar (respectively wind) is producing. Therefore, if we take the derivative with respect to Q_s, it yields:

$$\begin{cases} \alpha_A.\left(1 - \dfrac{\partial\overline{Q^+_{solar}}}{\partial Q_s} - p_{wind}.\dfrac{\partial\overline{Q^+_{wind}}}{\partial Q_s}\right) = 0 \\ \alpha_A.\left(1 - p_{solar}.\dfrac{\partial\overline{Q^+_{solar}}}{\partial Q_s} - \dfrac{\partial\overline{Q^+_{wind}}}{\partial Q_s}\right) - \alpha_B.\left(\eta + \dfrac{\partial\overline{Q^+_{wind}}}{\partial Q_s})\right) = 0 \end{cases}$$

And finally:

$$\begin{cases} \dfrac{\partial\overline{Q^+_{solar}}}{\partial Q_s} = \dfrac{\alpha_A.(p_{solar} - 1) + \alpha_B.\eta}{\alpha_A.(p_{wind}.p_{solar} - 1) - \alpha_B} \\ \dfrac{\partial\overline{Q^+_{wind}}}{\partial Q_s} = \dfrac{\alpha_A.(p_{wind} - 1) - \alpha_B.(1 + \eta.p_{wind})}{\alpha_A.(p_{wind}.p_{solar} - 1) - \alpha_B} \end{cases}$$

Proof of Proposition 6

The zero profit conditions yield for the new capacities:

$$\begin{cases} \mathbb{E}\big[\big(P_1 + \alpha_A.(Q_s - Q^+_A - Q^+_{solar} - Q^+_{wind}) - k_{solar}\big).Q^+_{solar}\big] = 0 \\ \mathbb{E}\big[\big(P_1 + \alpha_A.(Q_s - Q^+_A - Q^+_{solar} - Q^+_{wind}) + P_2 - \alpha_B.(\eta.Q_s + Q^+_A + Q^+_{wind}) - k_{wind}\big).Q^+_{wind}\big] = 0 \\ \mathbb{E}\big[\big(P_1 + \alpha_A.(Q_s - Q^+_A - Q^+_{solar} - Q^+_{wind}) + P_2 - \alpha_B.(\eta.Q_s + Q^+_A + Q^+_{wind}) - k_A\big).Q^+_A\big] = 0 \end{cases}$$

Again, we take the derivative with respect to Q_s:

$$\begin{cases} \alpha_A.\left(1 - \dfrac{\partial\overline{Q^+_A}}{\partial Q_s} - \dfrac{\partial\overline{Q^+_{solar}}}{\partial Q_s} - p_{wind}.\dfrac{\partial\overline{Q^+_{wind}}}{\partial Q_s}\right) = 0 \\ \alpha_A.\left(1 - \dfrac{\partial\overline{Q^+_A}}{\partial Q_s} - p_{solar}.\dfrac{\partial\overline{Q^+_{solar}}}{\partial Q_s} - \dfrac{\partial\overline{Q^+_{wind}}}{\partial Q_s}\right) - \alpha_B.\left(\eta + \dfrac{\partial\overline{Q^+_A}}{\partial Q_s} + \dfrac{\partial\overline{Q^+_{wind}}}{\partial Q_s})\right) = 0 \\ \alpha_A.\left(1 - \dfrac{\partial\overline{Q^+_A}}{\partial Q_s} - p_{solar}.\dfrac{\partial\overline{Q^+_{solar}}}{\partial Q_s} - p_{wind}.\dfrac{\partial\overline{Q^+_{wind}}}{\partial Q_s}\right) - \alpha_B.\left(\eta + \dfrac{\partial\overline{Q^+_A}}{\partial Q_s} + p_{wind}.\dfrac{\partial\overline{Q^+_{wind}}}{\partial Q_s})\right) = 0 \end{cases}$$

It clearly appears by withdrawing the second line from the third line that:

$$(p_{wind}-1).\frac{\partial\overline{Q^+_{wind}}}{\partial Q_s}=0$$

And consequently that this linear system boils down to the same as Proposition 5 with $p_{wind}=1$.

Proof of Proposition 7:

In the long run, the change in CO_2 emissions reads:

$$\Delta E_{CO_2}=(e_A-\eta.e_B).Q_s-e_A.\left(p_{solar}.\overline{Q^+_{solar}}+p_{wind}.\overline{Q^+_{wind}}\right)-e_B.p_{wind}.\overline{Q^+_{wind}}+(e_A-e_B).\overline{Q^+_A}$$

Therefore, by combining with the results of Proposition 6, we get:

$$\begin{aligned}\frac{\partial E_{CO_2}}{\partial Q_s}=e_A.&\left(1-p_{solar}.\frac{1+\eta}{1+C.(1-p_{solar})}+\frac{C.(1-p_{solar})-\eta}{1+C.(1-p_{solar})}\right)\\&-e_B.\left(\eta+\frac{C.(1-p_{solar})-\eta}{1+C.(1-p_{solar})}\right)\end{aligned}$$

$$\frac{\partial E_{CO_2}}{\partial Q_s}=\frac{C.(2.e_A-e_B.(\eta+1))(1-p_{solar})-e_A.((\eta+1).p_{solar}+\eta-1)}{1+C.(1-p_{solar})}$$

Because the denominator is positive, we can focus on the numerator. For instance, if $e_B\geq\frac{2}{\eta+1}e_A$ and $p_{solar}\geq\frac{1-\eta}{1+\eta}$, the numerator is negative and additional storage reduces emissions.

Appendix B

Technology	**CCGT**	**GT**	**Solar**	**Onshore**	**Offshore**
Overnight cost (€/kW)	754	400	750	1240	2742
Annual fixed costs (€/kW)	20	6.4	25	35	80
Unit variable cost (€/MWh)	45	135	0	0	0
Lifetime (years)	30	30	15	20	15
Efficiency (%)	57	38	-	-	-
Emissions rate (tCO_2/MWh)	0.33	0.55	0	0	0
Annual learning rate (%)	0	0	1.9	0.5	0.9

Table 4: Techno-economic parameters of new power facilities (Schröder et al. 2013)

Appendix C

	With new gas						Without new gas					
	2035			**2040**			**2035**			**2040**		
	$\mathbf{p_{CO_2}}$	**LR**	$\mathbf{p_{gas}}$	$\mathbf{p_{CO_2}}$	**LR**	$\mathbf{p_{gas}}$	$\mathbf{p_{CO_2}}$	**LR**	$\mathbf{p_{gas}}$	$\mathbf{p_{CO_2}}$	**LR**	$\mathbf{p_{gas}}$
V2G	28		60	14		22	1	2	4	1	1	2
Battery								-9	-1	3	-7	3
Hydrogen							-11		-8	6	5	2
CCGT			-2	-1		-5						
Solar	6		8	1		2	1		3	1		1
Onshore	1		1	1		2	2		3	1		1
Offshore			31	28		35	1		3	3		4
CO2	-7		-4	-13		-12	-6		3	-5		
Gas cons.	-3		-21	-11		-17	-1		-14	-2		-9

Table 5: Sensitivity analysis.
Figures represent the percentage change in long-term capacities, CO_2 emissions or gas consumption compared to the base case. No change is left blank.
p_{CO_2}: price of emissions increases from 80€ in 2022 to 100€
LR: yearly learning rate of stationary storage decreases from -3.5% to -2.5%
p_{gas}: price of gas doubles, from 15 to 30€/MWh$_{th}$

Appendix D

The problem is first formulated as a competitive equilibrium, where multiple agents solve their own program.

Storage firms

The arbitrage revenues of storage firm i, over the horizon $t \in T$ (one week), conditionally to the scenario ζ reads:

$$\Pi_{i,\zeta} = \sum_{t=0}^{T} \left((q^{out}_{i,\zeta,t} - q^{in}_{i,\zeta,t}).p_{c(i),\zeta,t} + R(E^{out}_{i,\zeta,t}) \right) \tag{21}$$

Storage firm i operates its storage asset in order to maximize its weekly revenues given the storage capacity.

$$\max_{\overline{s}_i, \overline{q^{in}}_i, \overline{q^{out}}_i} \left(\mathbb{E}\left[\max_{q^{out}_{i,\zeta,t}, q^{in}_{i,\zeta,t}, E^{out}_{i,\zeta,t}} \Pi_{i,\zeta} \right] - C_i \left(\overline{s}_i, \overline{q^{in}}_i, \overline{q^{out}}_i \right) \right) \tag{22}$$

Subject to:

$$s_{i,\zeta,t+1} = s_{i,\zeta,t} + \eta^{in}_i.q^{in}_{i,\zeta,t} - \frac{q^{out}_{i,\zeta,t}}{\eta^{out}_i} + E^{in}_{i,\zeta,t} - E^{out}_{i,\zeta,t} \tag{23}$$

$$s_{i,\zeta,0} = s_{i,\zeta,T} + \eta^{in}_i.q^{in}_{i,\zeta,T} - \frac{q^{out}_{i,\zeta,T}}{\eta^{out}_i} + E^{in}_{i,\zeta,T} - E^{out}_{i,\zeta,T} \tag{24}$$

$$\underline{s}_i \leq s_{i,\zeta,t} \leq \overline{s}_i \tag{25}$$

$$0 \leq q^{in}_{i,\zeta,t} \leq \overline{q^{in}_i}_i \tag{26}$$

$$0 \leq q^{out}_{i,\zeta,t} \leq \overline{q^{out}}_i \tag{27}$$

$$\sum_{t \geq t_2 > t-24} (q^{out}_{i,\zeta,t_2} + E^{out}_{i,\zeta,t_2}) \geq \sum_{t \geq t_2 > t-24} E^{in}_{i,\zeta,t_2}, \ \forall i \in \mathcal{I}_{PHS} \tag{28}$$

Equations 21 and 22 describe the objective of maximizing the expected profit. Firm i can either sell $q^{out}_{i,\zeta,t}$ and buy $q^{in}_{i,\zeta,t}$ on the wholesale market at price $p_{c(i),\zeta,t}$, or release $E^{out}_{i,\zeta,t}$ for other services and getting the revenue $R(E^{out}_{i,\zeta,t})$. Typically hydrogen can be sold on other markets, PHS plants must sometimes spill water for free and V2G consumes power while running. All these services use energy which is not valued directly through the power market. Meanwhile, the firm must account for the storage, charging and discharging capacities (respectively $\overline{s}_i$,

$\overline{q^{in}}_i$ and $\overline{q^{out}}_i$) but incurs a cost $C_i\left(\overline{s}_i, \overline{q^{in}}_i, \overline{q^{out}}_i\right)$[14].

Equations 23 and 24 formulate the energy conservation in the storage system between t and $t+1$, considering a charging efficiency η_i^{in}, a discharging efficiency η_i^{out}, an external (and free) input of energy $E_{i,\zeta,t}^{in}$, and an external output of energy $E_{i,\zeta,t}^{out}$. In this formulation, energy losses are considered both at the inlet and at the outlet of the storage system. Introducing external energy input allows the consideration of natural water inflow in a reservoir.

Notice that with how equation 24 is formulated, the stock at the end of the week should match the stock at the beginning of the week. This common value is determined optimally by the storage firms. This formulation is equivalent to an infinitely repeated week for which rational firms behave optimally based on perfect foresight. Some studies, such as Sioshansi et al. (2009), Connolly et al. (2011), and Byrne and Silva-Monroy (n.d.) estimate the impact for storage revenues of imperfect knowledge of prices. Sioshansi et al. (2009) show that perfect foresight assumption has a relatively small effect on operational decisions, since prices tend to follow predictable diurnal and seasonal patterns. Connolly et al. (2011) and Byrne and Silva-Monroy (n.d.) evaluate the revenues with relatively simple operational strategies and show firms can reach more than 80-95% of the maximum revenue earned with perfect foresight.

Inequality 25 imposes the stock $s_{i,\zeta,t}$ to stay above a minimum level[15] and lower than the storage capacity. Inequality 26 (resp. 27) makes sure that the storage input $q_{i,\zeta,t}^{in}$ (resp. output $q_{i,\zeta,t}^{out}$) remains non-negative and lower than the charging capacity (resp. discharging capacity). Finally, inequality 28 is interpreted as a must-run constraint essentially for PHS to ensure a relatively regular water output. The water flow is forced at least to equate the water inflow on the last 24h consecutive hours.

One could argue that a profit maximization program is well-suited to represent the firms behavior, but unfit for households owning EVs or V2G. We support this choice by acknowledging that households will progressively become aware and responsive to prices and that intermediary services will appear to aggregate and manage fleet of vehicles accordingly to the market signals, given the constraints provided by households.

Notice also that because $p_{c(i),t}$ appears in the equation as a exogenous variable which is not part of their controls, storage firms are price takers. They do not anticipate the impact of

[14] We apply a 5% discount factor to investment costs, and C_i represents the weekly fraction of the capital expenditures.

[15] The minimum level is set at 0 for all storage systems, except V2G, for which it is set at half the capacity. This value is consistent with Azadfar, Sreeram, and Harries (2015), who observe V2G owners prefer charging before running low on energy, disregarding the cost incurred.

their actions and the actions of their competitors on the market price. The literature delving into storage in imperfect markets is arguably well-developed and still flourishing. To some extent, we divert from this field by assuming perfect competition in our study. We make the case that new storage is fully scalable, with low economies of scale and therefore almost constant returns. Moreover, batteries use a similar type of technology regardless of their size and can operate across large geographic areas due to their easy insertion into the grid tense nodes (Karaduman 2021). This strongly participates to market efficiency in the field of new storage systems, which will in its turn decrease the market power of PHS plant.

Conventional producers

Conventional power producer j dispatches its plant according to the following program:

$$\max_{\overline{y}_j} \mathbb{E}\left[\max_{y_{j,\zeta,t}} \sum_{t=0}^{T} y_{j,\zeta,t} . \left(p_{c(j),\zeta,t} \underbrace{- c_j^v - p_{CO_2} . e_j - \frac{p_{fuel(j)}}{\eta_j}}_{\text{variable, CO}_2 \text{ and fuel costs}} \right) - \underbrace{C_j \left(\overline{y}_j \right)}_{\text{investment costs}} \right] \tag{29}$$

Subject to:

$$0 \leq y_{j,\zeta,t} \leq \overline{y}_j \tag{30}$$

$$RU_j . \overline{y}_j \geq y_{j,\zeta,t+1} - y_{j,\zeta,t} \tag{31}$$

$$RD_j . \overline{y}_j \geq y_{j,\zeta,t} - y_{j,\zeta,t+1} \tag{32}$$

Equation 29 describes the objective of maximizing the profit for firms j by selling $y_{j,\zeta,t}$ at price $p_{c(j),\zeta,t}$ but facing a variable cost c_j^v, a cost of CO_2 emissions considering a price p_{CO_2} and an emission rate e_j, and a cost of fuel (either gas or coal) considering a price $p_{fuel(j)}$ and an thermal to electricity efficiency η_j. New gas power plants can enter the market with a capacity $\overline{y}_j$ by incurring a cost $C_j(\overline{y}_j)$. Inequality 30 ensures that the production $y_{j,\zeta,t}$ remains non-negative and lower than the power plant capacity $\overline{y}_j$. Equations 31 and 32 represent constraints of ramping up and down, which are defined by the ability of the plant to increase or decrease its production between t and $t+1$. RU_j and RD_j respectively denote the percentage of nominal power by which the plant can increase or decrease its power output.

Market operator

The European market operator clears the national markets by balancing supply and demand

and minimizing the marginal cost of the dispatch, which can sometimes reach the value of unsupplied energy. It is typically peak shaving or load management decisions in exchange for a compensation, the value of lost load V_c, which is set at a country-level accordingly to the results of Shivakumar et al. (2017).

$$\min_{LL_{c,\zeta,t},PF_{c,c_2,\zeta,t},K_{c,\zeta,t}} \sum_{c\in\mathcal{C}} V_c.LL_{c,\zeta,t} \tag{33}$$

Subject to:

$$\underbrace{D_{c,\zeta,t} - LL_{c,\zeta,t} + \sum_{c_2\in\mathcal{C}}(PF_{c,c_2,\zeta,t} - PF_{c_2,c,\zeta,t})}_{\text{electricity demand}} = \underbrace{\sum_{j\in\mathcal{J}_c} y_{j,\zeta,t} + \sum_{i\in\mathcal{I}_c}(q^{out}_{i,\zeta,t} - q^{in}_{i,\zeta,t}) + \sum_{r\in\mathcal{R}_c} y_{r,\zeta,t} - K_{c,\zeta,t}}_{\text{electricity supply}} \tag{34}$$

$$0 \leq LL_{c,\zeta,t} \leq D_{c,\zeta,t} \tag{35}$$

$$0 \leq PF_{c,c_2,\zeta,t} \leq BC_{c,c_2} \tag{36}$$

$$0 \leq K_{c,\zeta,t} \leq \sum_{r\in\mathcal{R}_c} y_{r,\zeta,t} \tag{37}$$

$$0 \leq \sum_{j\in\mathcal{J}_c\cap\mathcal{J}_{nuclear}} y_{j,\zeta,t} \leq NA_{c,\zeta,t} \tag{38}$$

Equation 34 represents the market clearing equations in each country c, considering an exogenous and inelastic demand $D_{c,\zeta,t}$, a lost load $LL_{c,\zeta,t}$, borders exchanges between countries c and c_2 (powerflow $PF_{c,c_2,\zeta,t}$), an exogenous renewable production from source r, $y_{r_c,\zeta,t}$, and a curtailment of this production $K_{c,\zeta,t}$. According to 35, lost load is non-negative and cannot exceed the exogenous demand. Equation 36 translates that the powerflow between two countries is bounded by the current border capacity. No investment is possible in interconnections reinforcement. Equation 37 states that curtailment is limited by the amount of energy the renewable sources are feeding to the grid. It is implicitly assumed that any renewable plant can be stopped instantaneously at almost zero cost. Finally, equation 38 states that the sum of the nuclear production within a country should not be greater than the nuclear availability $NA_{c,\zeta,t}$, that depends on the period of the year, either for maintenance reasons or unavailability of sufficient cooling water inflows. Even if it is assumed that efforts are shared on all nuclear plants, in practice however, only the less efficient nuclear power plants will be curtailed by this equation.

Total cost minimization

Under price-taking assumption of firms and inelasticity of the demand, the multi-objective competitive problem formulated above can be rewritten as a minimization problem of the total cost of the power system, as given in 19.