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THE VALUE OF ELECTRIC ENERGY STORAGE IN ELECTRICITY SYSTEMS WITH HIGH SHARES OF WIND AND SOLAR PV: THE CASE OF FRANCE IN THE ENERGY TRANSITION

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Abstract

The adoption of ambitious targets for variable renewable energies (VRE) such as wind and solar has important effects on the technical and economic operation of power systems. Increasing shares of VRE will, in particular, require the deployment of more flexible and responsive technologies. Key flexibility providers in the scope are demand side management (DSM) and different forms of electric energy storage (EES) such as pumped hydroelectric (PHS), li-ion batteries (Li-ion), and compressed air (CAES), among others.

It has been previously shown how the value and the deployment of such new flexibility providers depended on the shares of VRE shares introduced into the system as developed in (Brijs et al., 2016; Van Stiphout et al., 2015; Villavicencio, 2017)*. Building on these works, this paper explores the value of storage in the context of a realistic brownfield model calibrated on the existing French electricity system. In particular, this paper compares the value of storage (a) in a system corresponding to the 2015's Energy Transition Act for 2020 and 2030. In 2020, 4.7 GW of DSM are sufficient to provide the required flexibility and no EES investments will be needed. By 2030, however, in addition to a comparable level of DSM, 3.2 GW of additional EES investments are required. These storage solutions would generate an economic value of € 350 million per year and would increases overall welfare by € 670 million per year by 2030. The study yields a number of additional policy relevant results. First, limiting nuclear production will open opportunities for alternative base and mid-load providers, mainly gas, implying a threefold increase of CO2 emissions compared to 2020 levels. Second, wind and PV increase their surplus at the expense of profit reductions of baseload conventional technologies. Third, peak-load capacity is reduced but the capacity remuneration mechanism (CRM) allows covering up fixed costs to attain the zero profit condition. Fourth, EES lowers the cost of VRE integration which under the assumption of a complete cost retrofitting to consumers, made them significantly better-off, benefiting from a less constrained system. Fifth, an important dynamic inconsistency exists concerning the investment path to optimally attain both 2020 and 2030 targets, which urgently requires a decision at the policy level for prioritizing or target harmonization.*

Keywords: Electricity storage, demand-side management, renewable integration, system value, welfare effects.

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INTRODUCTION

Apart from the limited and very site-specific hydroelectric resources, the dominant emerging renewable energy technologies are wind and photovoltaic. They are considered as variable renewable energies sources (VRE) because of their inherent supply variability. The significant technological progress they have achieved during the last decade together with the important cost reductions have made them be at the core of the claim for a clean energy future. Yet, they are non-dispatchable, their low capacity factors, as well as their difficult predictability, establish new operational and regulatory challenges, particularly when important shares are expected to be deployed on current power systems.

Storing energy and/or shifting demand from periods where there is an excess of VRE generation towards periods where there is an excess of residual demand creates value to the system (Black and Strbac, 2007; Carnegie et al., 2013; Connolly et al., 2012; Denholm et al., 2013; Fitzgerald et al., 2015; Van Stiphout et al., 2015). Some EES technologies have already proved market readiness (Berrada et al., 2016; KU Leuven Energy Institute, 2014; Luo et al., 2015; Mahlia et al., 2014; Palizban and Kauhaniemi, 2016) and are able to efficiently supply multiple services to the power systems such as investment deferrals on generation and grid assets by its firming value, reduce CO_2 emission[2] (Carson and Novan, 2013; de Sisternes et al., 2016), and alleviate reliability issues (Palizban and Kauhaniemi, 2016). Nevertheless, emerging flexibility technologies, such as EES and demand side management (DSM), are completely absent from the official targets and power sector roadmaps[3]. Decision makers still perceive them as not mature enough and costly because EES benefits use to be hidden behind regulatory veils[4].

This paper sheds light on the benefits, the value and the welfare effects of considering flexibility technologies for attaining the official RPS targets adopted. It is organized as follows: section 1 presents a survey of studies dealing with the role of new flexibility technologies and highlights the relevant issues to be tackled. Section 2 characterizes the sense of benefits and value of flexibility technologies under investigation, sets the necessary boundaries of the quantitative assessment and explains the procedure proposed. Section 3 exposes the case study based on the French official renewable portfolio standard (RPS) on the 2020 and 2030 horizons in which the system value of EES technologies are quantified. Surplus variations across producers are addressed and welfare effects are exposed. The final section discusses the limits of the study and concludes by highlighting the main findings and its policy implications.

[2] Under the right market conditions (i.e., sufficiently high CO2 cost or tax).

[3] Exceptions at state level exist in the US. In California, Legislation (AB 2514) enacted in September 2010 for the adoption of requirements for utilities to procure energy storage systems. This Assembly Bill instructs the California Public Utilities Commission (CPUC) to stablish EES targets for each of the three IOUs. The CPUC required on 2014 the utilities to collectively procure 1,325 MW of energy storage by 2020.

[4] High value sources may appertain to the regulated sector.

1. LITERATURE REVIEW

Assessing the value of generation and flexibility technologies involves quantifying its interactions with the rest of the system. It also relates using the available resources and including the energy policies in place. Such assessments are dependent on the methodology and the representation of the power system adopted. (Joskow, 2011) and (Keppler and Cometto, 2012) describe the need for moving from cost-based approaches, dealing with technical aspects of technologies at plant level with no consideration of the rest of the power system, to system-based approaches[5].

In this sense, electricity needs to be conceived as a heterogeneous commodity. From an economic point of view, the "heterogeneities of electric energy" explicit the variations of its marginal value associated with the location, time and steadiness of supply. (Hirth et al., 2016) exposes it instructively: physically, "technologies produce the same physical output (MWh of electricity)", but "economically, they produce different goods". The key figure this reveals is "substitutability"; it means that a megawatt-hour of electricity is only imperfectly substitutable along different moments, locations and system's states. Therefore, adopting a system framework is a requisite for assessing the complete value of a technology. Such frameworks are defined as integrated or whole assessment frameworks in which long-term choices (capital allocations) are accounted, but they have to be coupled with mid-term decisions (optimal economic dispatch, maintenance decisions, and inventory optimization) and real time dynamics (stability of supply and system reliability). Yet, those models use to be complex multidimensional equilibrium problems that are affected by the curse of dimensionality. Simplifications use to be implemented on a case by case basis constituting a trade-off exercise but troubling possible results comparisons.

There is an extensive literature on the subject of storage technologies for power system applications. A branch of this literature gives a technology comparison, describing the main characteristics of each technology and its potential applications (Evans et al., 2012; Eyer and Corey, 2010; Gyuk et al., 2013; Koohi-Kamali et al., 2013; Luo et al., 2015; Rubia et al., 2015; Yekini Suberu et al., 2014; Zhao et al., 2014). They introduce the technical capabilities of EES technology, bulk or distributed, and the benefits they may supply to the system, comments on the development challenges use to be also briefly commented. Some publications focus on the assessment of business cases of particular EES facilities on specific markets. In this literature, the hypothesis of "small-scale storage" is broadly adopted because the goal is to study the feasibility of EES applications from project finance perspective. This infers the important simplification of assuming EES to be a price-taker, thus, ignoring profit cannibalization effects (Denholm and Sioshansi, 2009; Ekman and Jensen, 2010; Figueiredo et al., 2006); Most of the time, only one technology and no a portfolio of technologies are studied using reduced temporal resolution (e.g., representative weeks) (Connolly et al., 2012; Sigrist et al., 2013; Walawalkar et al., 2007), hindering to extrapolate results obtained for this particular technologies to others with different technical characteristics and maturity. Moreover, different services use to be considered but are evaluated in isolation[6] (Butler et al., 2003; Denholm et al., 2013; Sioshansi et al., 2009; Walawalkar et al., 2007). Storage valuation literature also presents a relevant question dealing with cost-effectiveness as opposed to cost-optimality. Cost-effectiveness (Eyer and Corey, 2010; Kaun, 2013) implies adopting a merchant perspective where the monetizable potential of storage is limited to the boundaries of the owner of the storage facility where profits are maximized. Cost-optimal storage valuation adopts a system wide perspective where capacity and

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[5] In this sense, "economic approach" makes reference to the implementation of economic theory to make explicit the value of assets (i.e., power capacity) and products (i.e., energy and other services).

[6] Namely: energy arbitrage, resource adequacy or reserve supply.

dispatch are jointly optimized and technology specific externalities can be tacked into account (e.g., profit cannibalization effect due to price stabilization).

At the beginning of the decade, there was a rise in the interest for electricity storage as a potential solution to alleviate issues of price volatility of gas and electricity (Figueiredo et al., 2006; Sioshansi et al., 2009). In (Sioshansi et al., 2009), the authors present the economic principles of storage for price-arbitration on the PJM market. Using a parametric study they explore the influence of efficiency and energy capacity (storage dimensioning) of storage to capture revenues on the energy only market. They find that 1GW with 4h of storage for price-arbitration gathers 50% of maximum revenues; 8h and 20h would get 85% and 95% respectively. These findings evidence the fact that additional storage provides little incremental arbitrage opportunity[7]. They recognize the issues related to optimal storage dimensioning. They highlight that: *"There is no universal optimal size of storage because it will depend on the technology and planned applications"*. They identify a multiplier effect between an efficiency increase over the potential price-arbitration revenues. They explained by the interaction between price and quantities: a more efficient technology would not only need to charge during fewer hours to restitute the stock (lower quantity) but also would do it during the less expensive ones (lower prices). Therefore, the value of storage is technology specific[8], depends on the optimal sizing of the reservoir and the power conversion system (PCS) and is related to the applications/services considered[9]. Any unambiguous valuation of storage should consider the latter.

In (Black et al., 2005) It is showed how the value of storage increases over that of peaking units for high wind penetrations by implementing a parametric analysis of the UK power system using a partial equilibrium model. (Lamont, 2013) states that changing the capacity of one technology, including storage, may change the marginal value of the remaining ones because every power mix has an optimal economic dispatch related to the supply curve and the expected load. This is a key issue regarding the valuation of any technology in a market context. Hence, only by simultaneously optimizing capacity investments and dispatch decisions, the condition for cost-optimal capacity deployment may be undeniably satisfied. This is, for every technology in the system, equalizing the marginal value of capacity with its marginal cost at the equilibrium (Stoft, 2002). (Lamont, 2013) identifies two factors relating the marginal value of each of the EES components considered[10]. He outlines a "self-effect", manifested by a decrease in the marginal value of a component due to the increase in its own capacity, and a "cross-effect", where the marginal value of a component decreases as a result of the increase of other's capacity[11].

The business case of storage is particularly affected by its own inner presence because of its price stabilization effect. (Denholm et al., 2013a) point out the precise challenge faced by storage on a system perspective: while charging, storage is considered as an added demand which causes an

[7] The latter describe EES for price-arbitration as a production factor following the law of diminishing returns.

[8] Technology type defines the round-trip efficiency and costs (fixed and variable).

[9] Locational issues are also quite relevant on EES valuation. Network bottlenecks and congestion alleviation can add up to 38% premium to the arbitration value of storage (Sioshansi et al., 2009).

[10] Namely power capacity and energy capacity.

[11] This is explained by the impact that a marginal variation on the capacity of components would have over the merit order, modifying the electricity price, which will cause a change in the optimal inventory decisions of EES, affecting in turn its optimal dimensioning as wells as the that of the other technologies. This kind of sensitivities of components on the value of storage can only be captured by a co-optimization approach.

increase in the market price during off-peak periods. When discharging, storage acts as a generator, decreasing the price during peak periods. This effect reduces or, in the extreme case, eliminates its profits, even while continuing to provide benefits to the system and consumers.

In (Pudjianto et al. 2013) it is stated that the main elements that need to be considered when analyzing the system value of storage are: simulating over broad time horizons and using different asset representations. This is mainly because storage induces savings in operating costs but also can be complementary with generation and network assets, making investment deferrals and capital savings. This is particularly important when system requirements are tightly constrained, as it is the case for systems with significant shares of variable generation. Storage and DSM can also support congestion management on the T&D network, enabling savings on re-dispatch costs and investment deferrals (Fürsch et al., 2013; Steinke et al., 2013).

In (Strbac et al., 2012) and (Pudjianto et al., 2013) whole-system assessment models are implemented to assess the value of adding generic electricity storage to the UK power system. In this way, their models optimize investments in generation, network and storage capacities while considering reserve and security requirements. Their generic, or "technology-agnostic", approach about storage seeks to represent a different type of bulk and distributed EES technologies by testing possible ranges of cost and technical parameters. Both studies found the value of storage to be "split" across different sources coming from different segments of the industry. In (Strbac et al., 2012), the value of storage is assessed on 2020, 2030 and 2050 horizons. They find that the EES value significantly increases with the contribution of renewables. But they also recognize that even in the scenarios dominated by nuclear energy, storage has a role to play. When stacking the value sources on the reference case considered, the system savings produced by storage increase from £0.12 bn per year in 2020, to £2 bn in 2030, up to £10bn per year in 2050. Enhanced forecasting techniques, flexible generation, interconnections, and DSM are found to reduce the value of EES. Meanwhile, (Pudjianto et al., 2013) concentrates on the 2030 horizon, where wind share is estimated at 52.2%, focusing on the future cost uncertainty of storage technologies. They spread over wider detail on the parameters used for quantifying the value of storage related to its capital costs. They find that the cumulated value of EES goes from £0.1 bn to £2 bn per year when considering annualized investment cost ranging from 500£/kW per year to 50£/kW per year, for bulk and distributed EES.

In (Schill, 2013), a similar investment model including storage is proposed to study the role of storage on the German power system. Nevertheless, the model implements a rather stylized hourly dispatch where all thermal generators and storage are assumed to be perfectly flexible. Aggregated must-run levels are assigned to conventional technologies looking to reflect a combination of economic, technical, system-related and institutional factors to be met. Three storage technologies are considered using a fixed energy-power ratio linking investments into power capacity for charging or discharging (in MW) and energy capacity (in MWh). The official German energy and climate targets to 2022 and 2032 horizons are analyzed as the reference cases, where VRE capacity is expected to triple from 2010 to 2032. On this setting, he finds that storage investments are only triggered on the cases where VRE curtailment is constrained to at least 1%. Must-run levels considered have a high impact on the magnitude of triggered investments in storage. On average, for the 2022 horizon, feasible storage investments vary from zero to 9GW in 2022 and from 2 to 22GW in 2032 when VRE curtailment is constrained to 1% and 0.1% respectively and no must-run constraints are included.

In (Artelys, 2013), a study in a similar direction is presented for the case of France on the 2030 horizon. Nevertheless, the electricity mix considered is based on the capacities provided by public scenarios, so, the capacity of conventional technologies is exogenous to the model. No investments in storage are cost-optimal. This results should be taken with care because the scenarios adopted have been defined without considering ancillary services, therefore the value of flexibility technologies is incompletely assessed. (Lamont, 2013) previously recognized that analytically "finding an overall optimum is challenging" and can become even more complicated when multiple services are to be satisfied. In (Berrada et al., 2016) the economics of storage are studied considering the revenues coming from both arbitration and regulation within different markets. They find that cumulating revenues on multiservice supply allows EES to show a high probability of generating positive net present value (NPV). Other benefits of storage are also acknowledged broadening its potential value sources.

The results in (Go et al., 2016) suggest the value of storage to be widely influenced by the assessment framework. They compare the system value of storage obtained from a sequential optimization where generation-and-transmission-expansion are obtained in the first step, and storage is added in a second step, against the value resulting from the fully co-optimized ESS model they propose. They use a MILP formulation that co-optimizes investments in generation, transmission, and bulk ESS, as well as dispatch decisions subject to RPS constraints. No operational constraints are considered and the optimization is done over five representative days to assure numerical tractability. Even if the system value of storage increases with the RPS level required in both cases, they observe that the sequential optimization method captures at most 1.7% of the savings over the total system costs induced by storage on the co-optimization framework. Introducing co-optimized ESS improves energy balancing across the network, lowering integrations cost of VREs and reducing renewable curtailment. However, the main value source of storage under their co-optimization framework is given by the induced investment deferrals, which in economic terms correspond to capital stock substitutions.

The case of Texas is analyzed on the 2035 horizon in (de Sisternes et al., 2016). A capacity expansion model is implemented considering unit commitment constraints, reserve requirements and mass-based CO_2 limits representing total CO_2 emission caps. Two generic EES technologies are represented with fixed E/P ratios with exogenously-specified installed capacities varying in reasonable ranges. The parameters of the EES technologies considered are loosely calibrated to represent a Li-Ion kind unit and a PHS kind unit with 2:1 and 10:1 energy to power ratio respectively. Minimum and maximum capital cost levels are assumed to represent the cost uncertainty of EES technologies. The experimental setup contains 35 cases obtained by combining a set of seven EES levels and five scenarios of CO_2 emission limits. An additional scenario is included to represent a situation with restrictive CO_2 emissions (100 t/GWh) with no nuclear eligibility. The power system is modeled with hourly resolution but only four representative weeks are simulated in order to control dimensionality and keeping the problem tractable. The results show that even if EES technologies reduce average generation cost in all the cases regardless its capital cost, the total system savings induced are only positive in the case where lower bound capital cost is assumed for the "PHS-kind" unit. The savings induced by the "Li-ion kind" unit are neutral at best. In the case where VRE are the only alternative to attain the CO_2 limits imposed, it is found that storage has an important role to play and its presence reduce total system costs for both technologies. PHS kind units are feasible even for upper bound capital costs assumed. These findings coincide with the previously exposed in (Go et al., 2016) where the value of storage increase with the VRE penetration.

Therefore, even if the adoption of high resolution integrated approaches rather than specific business models, considering multiple services and using broad time horizons under co-optimization frameworks constitute the main converging aspects agreed in the literature related to storage valuation, there is no clear consensus, nor definition of the value of electricity storage on power systems and the way to assess it.

2. METHODOLOGY

2.1. Defining the role of storage

According to the literature, the benefits of electricity storage are diverse and include some relatively easily quantifiable ones such as investments deferrals, fuel savings, savings on the associated “wear and tear” cost savings, but there are others non-as-tangible such as enhancing system stability and security, facilitating firm capacity of VRE, improving insurance against VRE doldrums and fuel prices variations among others. These benefits can be simultaneously manifested or mutually exclusive. Figure 1 illustrates those sources regarding the system requirements and the voltage level they are connected.

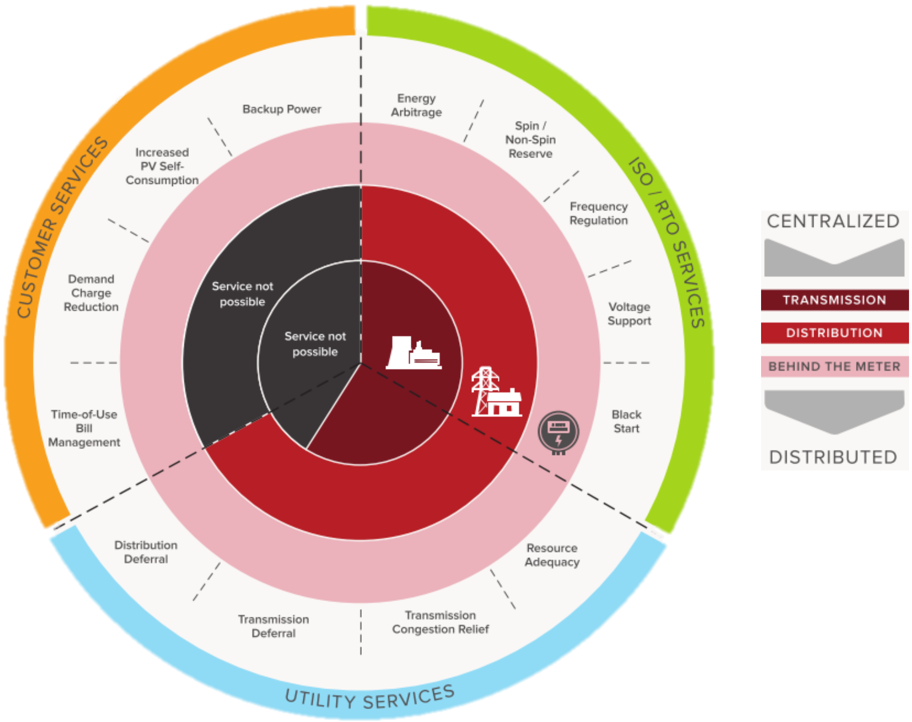

Figure 1. Services that can be provided by EES technologies.

Source: (Fitzgerald et al., 2015)

Moreover, the development of EES technologies can trigger benefits that are spilled out of the power sector itself like inducing industrial development, job creation, improving energy independence, among others. Therefore, a flawless accountant definition, as well as a clear delimitation of the boundaries, should be made when assessing the value of storage.

In this study, the system value of storage, hereafter denoted as “value”, is defined as the net monetizable system benefits generated directly or indirectly by storage, provided a cost-optimized system including optimal capacity allocations, as well as optimal dispatch and inventory decisions. In this sense, the meaning denoted by the value of storage refers to a market equilibria condition obtained by the joint deployment of generation capacity, DSM, and EES to balance multiple system services, considering only the power system.

The market value of storage, hereafter denoted as the profits of storage, is the resulting net profit obtained by subtracting stacked revenues coming from market participation with its associated costs.

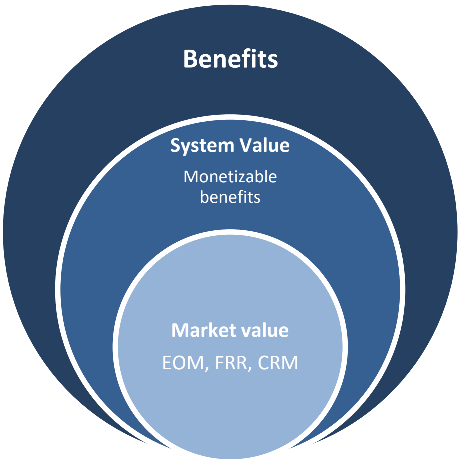

Figure 2. Benefits and value of storage

2.2. Defining the value of storage

Following the reasoning of (Pudjianto et al., 2013; Strbac et al., 2012), the system value of storage is accounted by the net system savings it induces. These savings are computed by calculating the difference in the total system cost between a cost-optimal system obtained when considering a full set of technologies in the investment portfolio, including storage, against a counterfactual system, where the same services need to be balanced but storage investments are not allowed. In the case where no storage investment proves optimality, the value of storage trivially equals to zero under the assumptions adopted because both cases converge to the same optimal system, which is a system without storage. Therefore, adding EES capabilities is valuable to the system if and only if the total system cost in presence of storage is lower than that obtained in the counterfactual case. Consequently, the value of storage is said to be captured in a systemic way. Under the assumption of perfect and complete markets, with no information asymmetries, the value of EES equals the net savings on system cost generated, because otherwise, the system cost would be higher without it.

As introduced on the literature review, in the case where significant shares of VRE are present on the system[12], storage can deliver the following benefits:

I. Reduce operating cost by improving the value factor of VRE, which induces fuel and CO_2 emissions savings;
II. Enhancing system's capability to absorb variability, so reducing capital and/or mothballing cost of existing capacity;
III. Reduce capacity investment by contributing to capacity adequacy;
IV. Offset the part-load efficiency losses and displace low load factor backup generation units with low efficiencies;
V. Supply low-cost load following capabilities to enhance reliability and decrease wear and tear costs;
VI. Supply system reliability by participating in the FRR requirements.

[12] Obtained either by an optimal economic deployment, or being imposed by voluntarist energy policies.

Those benefits should be accounted by the integrated assessment framework adopted. Nevertheless, the value of storage is quantified in relation to the cost variations it prompts over the cost categories considered by the objective function of the capacity expansion model (CEM) used. The present study applied the DIFLEXO model as the CEM tool for the analyses.

DIFLEXO accounts for the following value categories: O&M costs, CO_2 costs, DSM costs, load following costs (LFC), fuel costs, mothballing costs (MBC) and overnight (ON) costs. Other value sources of storage related to spatial arbitrations capabilities (i.e., congestion management, T&D investment deferrals) are not accounted since DIFLEXO doesn't include network representation. Only the economics of the power sector is included, therefore, no impacts on the job market or over other commodities and services are included. Further details of DIFLEXO are presented in the following section.

2.3. Brief DIFLEXO MODEL presentation

This section briefly presents the DIFLEXO model, which is a partial equilibrium model that represents the wholesale electricity market. It is an integrated generation expansion model (GEP) that endogenously co-optimizes investments in both generation capacity and new flexibility options such as electric energy storage (EES) and demand side management (DSM) capabilities. The model focuses on the study of flexibility needs by appropriately describing the operational constraints and the system services required at high temporal resolution. There is no grid representation on the current formulation of DIFLEXO. For the sake of parsimony, only a summarized description of the model is presented below; further details about the implementation of the model are given in Appendix A, while a comprehensive description of the model can be found in (Villavicencio, 2017)[13].

The main aspect of DIFLEXO is to differentiate system requirements allowing to find the most suitable mix of technologies in order to balance them at least cost. The model comprises stock allocation decisions taking into account short-term flexibility and FRR balancing requirements subject to technology specific operating constraints. It adopts a system cost perspective considering an LP formulation where capital cost, O&M costs, ramping cost, efficiency penalties for a partial load operation, wear and tear cost of units and CO_2 emission cost are quantified. Additional environmental considerations can also be added dealing with VRE curtailment cost, CO_2 caps, RPS requirements, and technology contribution restrictions[14]. VRE capacities bid in the market at zero marginal costs and VRE curtailment is allowed without penalties. The model is linear, deterministic, and solved in hourly resolution for one year. It was developed in GAMS and solved with CPLEX.

DIFLEXO finds the cost-optimal investments in new capacity as well as the optimal early retirements[15]. Finally, the welfare effect that cost-optimal EES capacity induces via price and quantity variations can be assessed by computing the outputs of the model. The resulting surplus variations across market players are calculated with respect to the equilibrium for the system with cost-optimal storage and for a counterfactual system under the same conditions but banning any new EES investment.

The equilibrium is defined by the minimization of total system cost comprising (see Appendix):

[13] The code of the model can be consulted on demand. For more information please contact: *manuel.villavicencio@dauphine.fr.*

[14] For example: Nuclear or coal phase-out.

[15] Under the contestable market assumption due to capital allocation rigidities see (Baumol et al., 1988; Brock, 1983).

- Investment and mothballing[16] costs: capital cost of new generating, storage and DSM capabilities are calculated using annualized capacity recovery factors (CRF). These parameters are inputs of the model. EES investments on power and energy capacities are considered separately for every technology defining ranges of E/P ratios to constrain them. DSM capabilities[17] are enabled simultaneously by investing on the required infrastructure (Bradley et al., 2013), thus, only one *crf* is assigned to them. Mothballing cost is accounted as a fixed cost equal to a factor associated with the overnight cost for every technology.
- Running costs: Running costs of conventional units are divided into O&M cost, fuel cost, CO_2 cost, and load following cost. O&M costs are a function of power generation. Fuel consumption is affected by the part-load efficiency losses. Therefore, fuel costs and CO_2 costs are corrected to account for the increase in fuel consumption when units are generating outside its rated capacity. Load following costs are proportional to the absolute value of the difference of synchronized power of two consecutive periods (ramping costs). Storage O&M costs account for both charging and discharging modes independently. O&M costs of DSM aggregates its activation cost, the Energy Management System (EMS) maintenance costs and the Data and Communication Company (DCC) operational expenditures. A zero fixed but high marginal cost alternative corresponding to the value of lost load (*VoLL*)[18] was included to account for brownouts[19].

System services are represented by the following equality constraints:

- Energy-only market (EOM): It represents the hourly balance between demand and supply for electricity. Where VRE generation is endogenously computed by assuming a homothetic extrapolation of the historical hourly production curve amplified by the cost-optimal capacity added for every VRE technology; VREs are assumed to have zero marginal costs (i.e., wind and solar power) and its curtailment is allowed.
- Operating reserve requirements (FRR): Consisting of frequency restoration reserves (FRR) as suggested by (ENTSO-E, 2013; Van Stiphout et al., 2015). Four types of reserve requirements are considered by combining the following categories: automatic and manual activation, with upward and downward directions. Reserve types are statistically dimensioned to account for net load uncertainty (De Vos et al., 2013; Hirth and Ziegenhagen, 2015; Van Stiphout et al., 2014). Conventional units and storage units provide frequency regulation up to the usual technical limits.
- The capacity-adequacy mechanism[20] (CRM): It is a constraint describing a decentralized capacity obligation mechanism based on (National Grid, 2016; RTE, 2016), where the capacity level is defined as a function of the peak load, the thermo-sensitivity of demand and the contribution of interconnections to capacity. The contribution of generators of every

[16] Also denoting early retirement costs.

[17] Load shifting and load shedding.

[18] The VoLL is set to 10 000€/MWh.

[19] Loss of load situations are unplanned load curtailments.

[20] Even if the model represents a perfect and complete market without risk aversion including demand-side flexibility and storage, which is in theory able to deliver socially optimal investment levels assuming a *VoLL* properly set (see (Keppler, 2017)), a representation of a CRM was implemented in the formulation to simulate the case of France. Including a CRM is necessary to evaluate its implications over the cost-optimal power mix and, hence, over the value of the technologies under study.

technology to system adequacy is obtained by multiplying technology specific de-rating factors.

The problem is constrained by the following sets of inequalities dealing with the representation of operational constraints:

- Operational constraints: Include Minimum Stable Generation (MSG) levels and maximum output constraints; ramp-up and ramp-down constraints; available frequency response and reserve constraints for every technology. Storage technologies have two operational constraints dealing with minimum and maximum inventory levels, and two constraints dealing with the inventory availability restrictions to participate on the FRR supply while charging or discharging. DSM capabilities for load shifting have an associated constraint that limits the shifting period; meanwhile, a time recovery constraint restricts the maximum consecutive periods for load shedding (Zerrahn and Schill, 2015).
- Energy policy constraints: Constraints describing the RPS targets; the nuclear moratorium policy; a CO_2 emission constraint is implemented but applied discretionarily.

2.4. Quantifying the Welfare effects of storage

In (Grünewald, 2011), an introduction of the welfare effects of storage and demand elasticity is given for a short-term setting on the energy-only market. It is presented how the price arbitration enabled by storage flattens the price duration curve, which is traduced by a clockwise rotation of the marginal production cost (MPC)[21] around a pivot point which is located in relation to the state of the power system triggering two opposite effects over social welfare: decreasing price levels during peak periods while discharging produces welfare gains; meanwhile, when charging, the supplementary demand increases price levels during off-peak periods, producing welfare losses. In both cases, the elasticity of demand improves the figure for overall welfare gains.

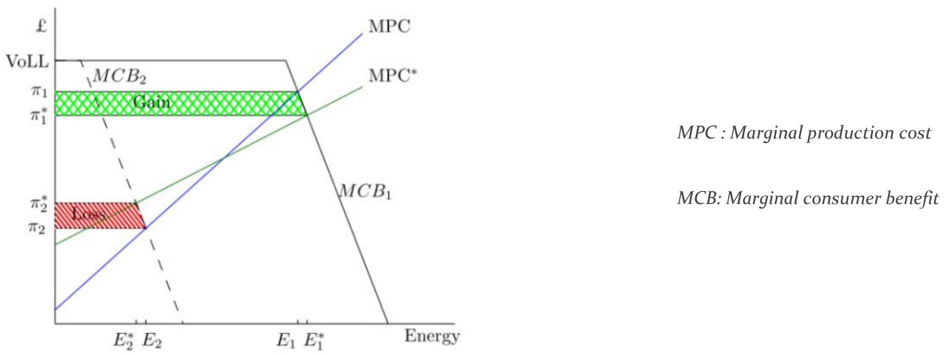

Figure 3. Welfare effects of storage during peak and off-peak periods. Source: (Grünewald, 2011)

This framework needs to be enlarged to account for DSM capabilities and long terms considerations were the main slope of the MPC curve would change. DSM capabilities create an elasticity of demand of different nature than storage but with similar effects. Load shifting is constrained by the assumption of holding constant well-being levels over the shifting period[22]. Load shedding is assumed as a planned load curtailment capability. It is constrained by a shedding cap and maximum consecutive calls. Thus, actions in one period of time would impact others in subsequent periods,

[21] The MPC on the case of the EOM correspond to the merit order curve.

[22] This means that an upward shift on demand on time "t" is compensated with the summation of downward shifts inside the the period (t-Ls, t+Ls), where Ls is the radius of the load shifting period. This makes net shifts to cancel out inside the moving window.

similarly to that of storage while charging and discharging. Therefore, foresight assumptions would have relevant implications on the calculation of the welfare effects. Interpreting these issues in the theoretical framework exposed in (Grünewald, 2011) implies assuming time-load dependencies over the extent of the MCB[23] shifts and MPC rotations. Moreover, in the case where mid or long-term optimization is adopted, the power and flexibility capacities are co-optimized, thus, the supply curve is no longer given but optimally shaped to enhance technologic complementarities with storage, enhanced the social welfare gains.

The further analytical development of the welfare effects enabled by new flexibility options is out of the scope of this paper. Nevertheless, the modeling approach adopted allows obtaining hourly prices and quantities on every setting (with and without EES) by computing the outputs of the simulations, which makes possible to numerically estimate the welfare effects prompted by storage. The three markets considered are assumed to be cleared at marginal price, which assures the at least zero profit condition for marginal units. Quantities are calculated by representing inelastic residual demands but enabling demand-side capabilities, as well as charging and discharging actions of storages. Resulting revenues and costs allows computing profits by technology in every case. The comparison of profits by market players on every setting allows assessing the welfare effects of storage in terms of surplus variations. Surplus variations of consumers and DSM are accounted separately. Consumers correspond then to the inelastic part of the demand and are supposed to be charged for the hourly electricity prices and the annual capacity obligation cost.

To the knowledge of the author, the distributional question of analyzing the welfare effects triggered by cost-optimal investments on new flexibility technologies, while balancing multiple services of the system, has not yet been developed elsewhere.

3. THE CASE OF FRANCE UNDER THE 2015 ENERGY TRANSITION ACT

3.1. Input Data

In France, the "Loi pour la transition énergétique"[24] (Energy Transition Act n° 2015-992) defines the target of renewable energy contribution by 2020 to be 27% and by 2030 to 40%. Additionally, the nuclear capacity is to be capped to 63.2 GW, and its contribution should decrease from 75% to 50% by 2025. On this context, the case for new flexibility technologies could be of relevance since the need for system services would likely rise and energy policy intervention would open new market opportunities.

The system has been calibrated to the French power system using publicly available data from the year 2015[25], where hourly demand, water inflows of reservoirs, VRE generation profiles and day-ahead forecast errors are available. The system is characterized by a peak demand of 92.63 GW and a total energy demand of 541.4 TWh. On the 2020 horizon, demand is supposed to stay at the same levels, while it is assumed to slightly increase 1% by 2030. Therefore, the system is optimized on a mid-term perspective by adopting a brownfield situation where the initial capacity is set to that of the French power system of 2015. There is no remaining potential to further develop reservoir hydro

[23] Marginal consumer benefit.

[24] Journal officiel "Lois et Décrets" - JORF n°0189 du 18 août 2015 (Officieal Act n°0189 of 18 August 2015) :

https://www.legifrance.gouv.fr/eli/jo/2015/8/18.

[25] RTE data source: www.rte-france.com/en/eco2mix/eco2mix.

capacity. The maximum potential for PHS and DCAES investments are estimated at 9.88 GW and 2 GW respectively. Cost and technical parameters are extracted from (Carlsson, 2014; IEA/NEA, 2015; Schröder et al., 2013; Simoes et al., 2013). Fuel prices are average 2015 market prices and CO_2 prices correspond to a flat rate of 20 €/t. A fixed WACC rate of 7% was presumed across all the technologies.

Technology	***Capital cost*** *[€/KW]*	***Lifespam*** *[yr]*	***crf_i*** *[€/KW yr]*	***$O\&M^f$*** *[€/KW yr]*	***$O\&M^V$*** *[€/MWh]*	***fuel_cost*** *[€/MWh]*	***CO_2 content*** *[t CO_2/MWh]*	***Ramping cost*** *[€/MW]*	***Initial capacity*** *[GW]*
Nuclear	*4249*	*60*	*295,1*		*10,0*	*7,0*	*0,015*	*55*	*63,13*
Hard coal	*1643*	*40*	*101,7*		*6,9*	*19,8*	*0,96*	*30*	*6,34*
CCGT	*1021*	*30*	*67,9*	*included*	*4,7*	*51,7*	*0,359*	*20*	*10,46*
OCOT	*637*	*30*	*42,4*	*on*	*7,3*	*67,3*	*0,67*	*10*	*-*
OCGT	*708*	*30*	*47,1*	*the crf*	*6,1*	*51,7*	*0,593*	*15*	*8,78*
Reservoir hydro	*3492*	*80*	*202,6*		*0,0*	*0,0*	*0*	*8*	*8,22*

Table 1. Parameters of generation technologies. Sources: (IEA/NEA, 2015, 2010; Schröder et al., 2013)

Technology	***Initial capacity***	***CAPEX -2020***					***OPEX -2020***			
	[GW]	***System*** *[$/KW]*	***Battery*** *[$/MWh]*	***Lifespam*** *[yr]*	***WACC*** *[%]*	***crf^E*** *[€/KWh yr]*	***crf^S*** *[€/KW yr]*	***$O\&M^V$*** *[€/KWh]*	***$O\&M^F$*** *[€/KW]*	***Source***
Li-ion	*–*	*510*	*200 000*	*10*	*7%*	*28,5 €*	*72,6 €*	*2,6 €*	*2,4 €*	*(Viswanathan et al., 2013)*
NaS	*–*	*950*	*332 500*	*10*	*7%*	*135,3 €*	*47,3 €*	*2,0 €*	*14,3 €*	
VRFB	*–*	*810*	*109 700*	*10*	*7%*	*115,3 €*	*15,6 €*	*2,0 €*	*16,2 €*	
PHS	*4,3*	*1 500*	*-*	*60*	*7%*	*106,8 €*	*- €*	*- €*	*22,5 €*	
DCAES	*–*	*600*	*35 000*	*55*	*7%*	*43,0 €*	*2,5 €*	*1,2 €*	*7,8 €*	*(Carlsson, 2014)*
Flywheel	*–*	*600*	*3 500 000*	*20*	*7%*	*56,6 €*	*330,4 €*	*2,0 €*	*8,4 €*	
Lead_acid	*–*	*390*	*164 000*	*8*	*7%*	*68,6 €*	*28,8 €*	*0,8 €*	*5,5 €*	
ACAES	*–*	*843*	*40 000*	*50*	*7%*	*79,6 €*	*3,8 €*	*3,1 €*	*3,9 €*	*(Zakeri and Syri, 2015)*

Table 2. Cost assumptions of EES technologies by 2020

Technology	**Year**	**Overnight cost** [€/KW]	**Lifespan** [yr]	**crf_i** [€/KW yr]
Wind	*2020*	*1350*	*25*	*118,6*
PV		*1100*	*25*	*95,8*
Wind	*2030*	*1300*	*25*	*114,1*
PV		*890*	*25*	*77,5*

Table 3. Cost assumptions of VRE technologies. Source: (Carlsson, 2014)

Technology	**Initial Capacity**	**CAPEX -2030**						**OPEX -2030**		**Source**
		System	**Battery**	**Lifespam**	**WACC**	**crf^E**	**crf^S**	**$O\&M^V$**	**$O\&M^F$**	
	[GW]	[$/KW]	[$/MWh]	[yr]	[%]	[€/KWh yr]	[€/KW yr]	[€/KWh]	[€/KW]	
Li-ion	*–*	*418**	*196 000**	*10*	*7%*	*23,5 €*	*71,2 €*	*2,6 €*	*2,0 €*	*(Viswanathan et al., 2013)*
NaS	*–*	*930*	*331 500*	*10*	*7%*	*132,4 €*	*47,3 €*	*2,0 €*	*14,0 €*	*(Carlsson, 2014)*
VRFB	*–*	*730*	*86 180*	*10*	*7%*	*103,9 €*	*12,3 €*	*2,0 €*	*14,6 €*	
PHS	*4,3*	*1 500*	*-*	*60*	*7%*	*106,8 €*	*- €*	*- €*	*22,5 €*	
DCAES	*–*	*530*	*31 060*	*55*	*7%*	*38,0 €*	*2,2 €*	*1,2 €*	*6,9 €*	
Flywheel	*–*	*483*	*2 500 000*	*20*	*7%*	*45,6 €*	*236,0 €*	*2,0 €*	*6,8 €*	
Lead_acid	*–*	*370*	*154 000*	*8*	*7%*	*65,1 €*	*27,1 €*	*0,8 €*	*5,2 €*	
ACAES	*–*	*742***	*35 200***	*50*	*7%*	*70,3 €*	*3,4 €*	*3,1 €*	*3,9 €*	*(Zakeri and Syri, 2015)*

*Assuming a cost reduction of 18% and 2% referred to 2020's levels for system and battery respectively
*Assuming a cost reduction of 25% referred to 2020's levels for both system and battery

Table 4. Cost assumptions of EES technologies by 2030

3.2. Results

3.2.1. Horizon 2020

In order to respect the RPS on 2020, 44.4 GW of wind should be added to the system. At this penetration level, wind supply competes directly with base load technologies. As it was previously introduced, the modeling framework implemented considers endogenous investments which promote a value-competition between technologies on a system costs minimization.

On this horizon both cases converge to the same results: flexibility needs are exacerbated and are optimally supplied by enabling 4.68 GW of DSM and by adding 15.87 GW of fast OCOT. No storage investments are triggered, suggesting that DSM is more value-competitive than storage under the assumptions adopted. Hard coal capacity competes with Wind generation on the EOM and with more flexible technologies, like gas-fired turbines, for system services supply required to handle the variability. This competition, together with the CO_2 emission costs due to its more important carbon content, makes Hard coal capacity to be totally mothballed from the mix. It is worth noting that under the capital and fuel cost assumptions adopted, CCGT capacity is completely put on-hold[26] as well. Its market shares are relocated to more flexible existing OCGT and new OCOT.

Technology	***Capacity Investments*** *[GW]*	***Mothballed capacity*** *[GW]*	***Total capacity H2020*** *[GW]*
Nuclear	-	-	63,13
Hard coal	-	-6,34	-
CCGT	-	-10,46	-
OCOT	15,87	-	15,87
OCGT	-	-	8,78
Reservoir	-	-	8,21
Wind	44,38*	-	51,36
PV	-	-	3,43
PHS	-	-	4,30
DSM	4,68	-	4,68

* Resulting from the RPS target imposed

Table 5. Investment and retirement decisions

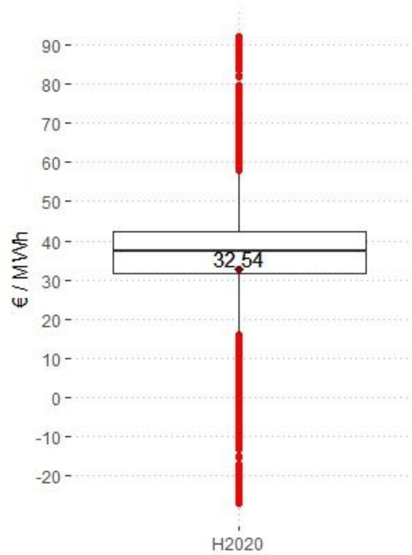

Figure 4. Electricity price distribution by 2020.

[26] CCGT is either mothballed or decommissioned.

Min. [€/MWh]	1st Qu. [€/MWh]	Median [€/MWh]	Mean [€/MWh]	3rd Qu. [€/MWh]	Max. [€/MWh]
-27,0	31,7	37,4	32,5	42,2	92,3

Table 5. Electricity price statistics H2020

Even with the enhanced flexibility of the resulting mix, the system still shows some difficulties to integrate VRE variability. Table 5 presents the distribution of resulting electricity prices on this horizon. Approximately 95% of the time the electricity price is between 17 €/MWh and 58 €/MWh. Nevertheless, it can be seen an important number of periods where prices go up to 92.3 €/MWh during peak periods but also experiencing a non-negligible number of hours at negative levels. The price spread is 119.3 €/MWh. The total system adequacy required by 2020 is estimated to 97.38GW, from which close to 80% is guaranteed by conventional units, particularly by the existing nuclear capacity. Existing reservoir hydro and new wind capacity also support the system on capacity. CO2 emissions by 2020 are 19.6 mton/year.

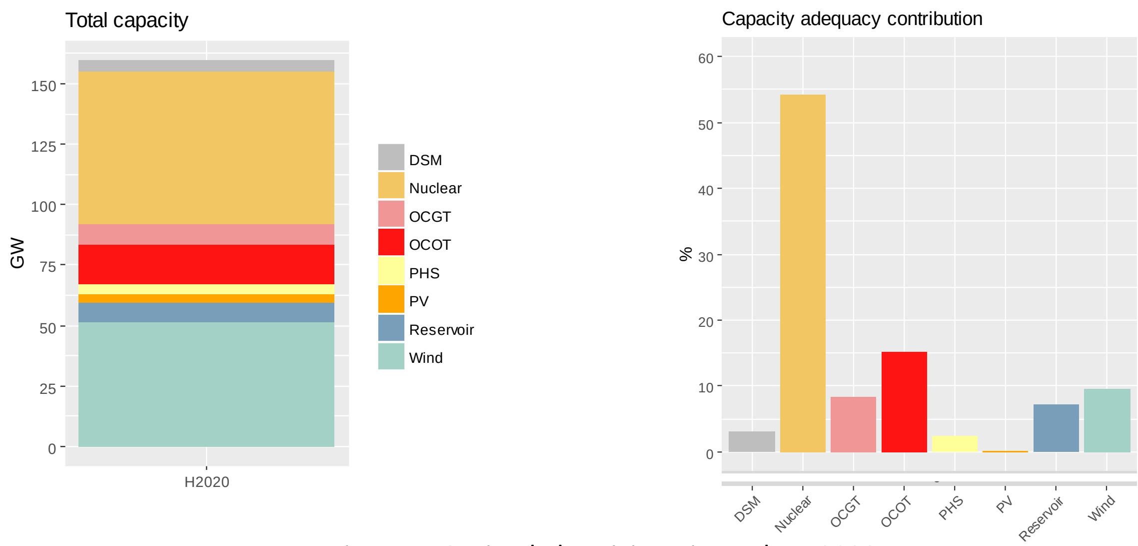

Figure 5. Optimal electricity mix on the H2020

3.2.2. Horizon 2030

The strengthened RPS requirements and the voluntarist reduction of nuclear shares entail a significant shock to the system. On this horizon, cost-optimal investments on storage capacity are triggered. The resulting capacity is presented in Table 6. In order to attain the 40% of VRE targeted on the official RPS, Wind capacity almost doubles with respect to the 2020 levels in both cases. The required investments in VRE capacity significantly reduces with storage: PV investments are 16.62 GW when co-optimized with storage instead of 19.9 GW; Wind capacity required is 72.23 GW with storage instead of 73.28 GW. This suggests the benefits of storage for improving the capacity value of VREs, therefore triggering fuel savings and investment deferrals.

By 2030 there is an exacerbated need for flexible capacity due to the higher shares of VRE imposed. Under the assumptions adopted, 4.68 GW of DSM is deployed and it is optimal to invest in 2 GW of

DCAES[27] and 1.23 GW of ACAES to further enhance system flexibility. Even with this EES investments still, 8.61 GW of OCOT are required. Otherwise, 11.72 GW of additional OCOT capacity would be needed without EES investments. Although, the OCOT capacity levels are sensitively lower than that obtained for 2020. The latter can be explained by the partial retirement of nuclear imposed by this horizon, making CCGT and Hard coal to remain on the system. Regarding the nuclear sector under the moratorium, 14 and 15.11GW are phased-out by 2030 with and without EES respectively, against no retirement required on 2020 (with no moratorium). The initial CCGT capacity thus remains in the system and is only partially retired. Therefore, the nuclear decommissioning opens new market opportunities for mid and baseload generation technologies which, under the multiservice framework considered, would also supply some flexibility to the system, reducing the cost-optimal capacity of OCOT compared to that of 2020. EES replaces around 3.1 GW of added OCOT capacity, while the remaining 4.15 GW are replaced by CCGT. The lower retirement of nuclear and hard coal when EES investments are allowed can be explained by the savings on the running costs per available capacity obtained, facilitating the more efficient dispatch of baseload capacity. EES seems to be complementary with baseload capacity and contributes to firm capacity, confirming the intuition that EES competes with high short-run marginal cost units and complement low show-run marginal cost ones.

Technology	***Investments*** *[GW]*		***Mothballing*** *[GW]*		***Total capacity*** *[GW]*	
	EES	*noEES*	*EES*	*noEES*	*EES*	*noEES*
Nuclear	-	-	*-14,04*	*-15,11*	*49,09*	*48,02*
Hard coal	-	-	*-4,06*	*-4,63*	*2,28*	*1,71*
CCGT	-	-	-	-	*10,46*	*10,46*
OCOT	*8,61*	*11,72*	-	-	*8,61*	*11,72*
OCGT	-	-	-	-	*8,78*	*8,78*
Reservoir	-	-	-	-	*8,21*	*8,21*
Wind	*72,73*	*73,28*	-	-	*79,71*	*80,26*
PV	*16,62*	*19,90*	-	-	*20,05*	*23,33*
PHS	-	-	-	-	*4,30*	*4,30*
DSM	*4,68*	*4,68*	-	-	*4,68*	*4,68*
DCAES	*2,00*	-	-	-	*2,00*	-
ACAES2	*1,23*	-	-	-	*1,23*	-

Table 6. Investment and retirements decisions on H3030 with and without EES

[27] It is worth noting that the total potential resource assumed for DCAES is exploited, therefore, the constraint relating this maximal capacity binds.

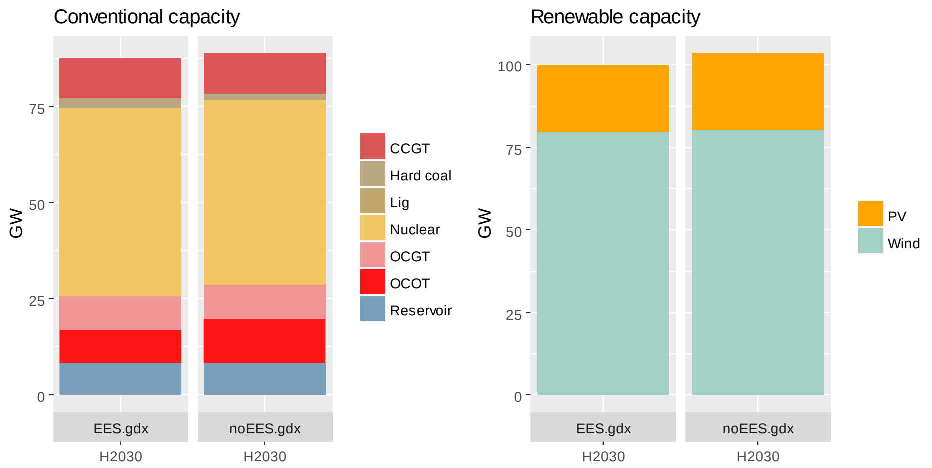

Figure 6. Optimal generation capacity

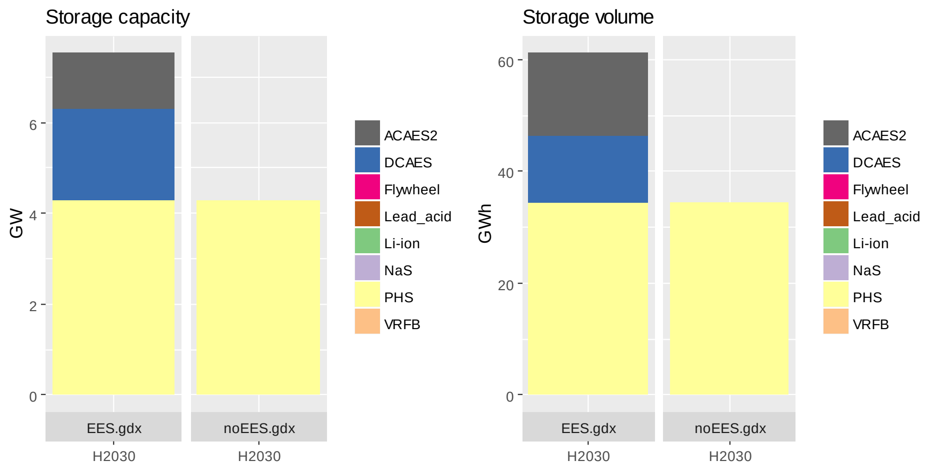

Figure 7. Optimal EES capacities

By 2030, the capacity adequacy requirement is estimated at 98.36 GW. Similarly than in the 2020 horizon, the capacity adequacy balance is dominated by conventional technologies. The participation of nuclear only reduces around 12 points compared to 2020 levels, corresponding to the de-rated decommissioned capacity. As expected, the available CCGT capacity further contributes to adequacy.

The resulting value of storage for capacity adequacy is depicted in Figure 8, where the DCAES and ACAES with a small participation of nuclear and hard coal on the left side of the graph, displace OCOT shares on the right.

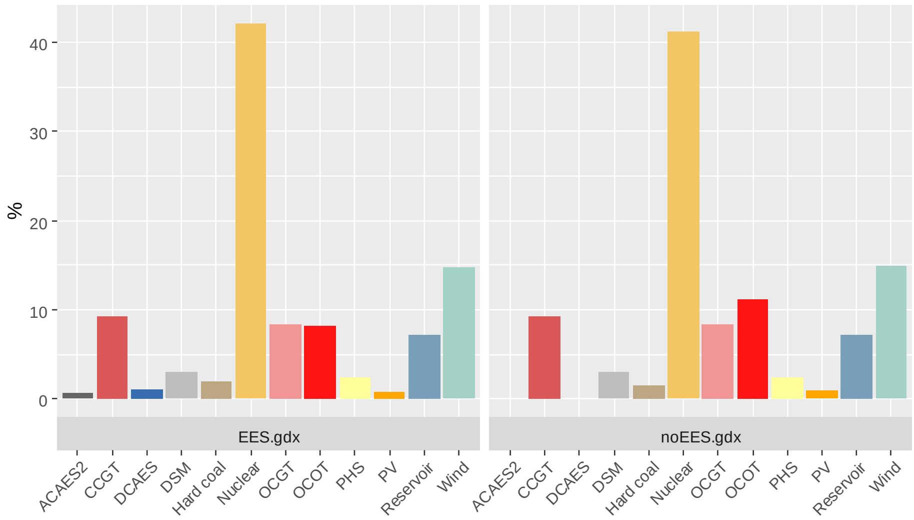

Figure 8. Capacity adequacy contribution of available capacity on H2030

CO_2 emissions grow from 56.4 to 58.2 mton/year. Therefore, a closer regulation of the environmental mechanisms for quota allocations should be considered to internalize environmental externalities. Additionally, the emissions levels of 2030 represent almost a threefold of that of 2020's. This high increase in emissions is caused by the nuclear moratorium imposed from 2025.

The effect of storage on market prices

The effect of storage on electricity prices is presented in Table 7 and Figure 9. Other costs related to the RPS targets are presented in Table 8. Compared to the results obtained on the 2020 horizon, there are no outliers on the boxplots, suggesting that system flexibility has been improved. Besides of this, the price-spread increases on 2030 given that more variability is added to the system. This increase is driven by higher prices. The minimum price levels are slightly higher but also more frequent than on 2020, suggesting that even if the system better integrates VREs[28], price variability increases in any case due to the higher VRE shares.

Moreover, storage investments have a partial but unambiguous price stabilization effect; they reduce interquartile price differences and price-spread compared to the case without storage. But, storage has a stronger effect on low prices with a particular alleviation of negative prices when charging: in the case without storage, 50% of the prices are in the (-19.4; 100.1) €/MWh range, while with storage this range shrinks to (-8.5; 98.1) €/MWh. This effect makes the average price to slightly increase from 65.5 €/MWh without storage to 68.1 €/MWh.

[28] VRE are better integrated because less capacity is required to attain the same shares imposed by the RPS target by this horizon, which necessarily means, lower VRE curtailment.

	Min.	1st Qu.	Median	Mean	3rd Qu.	Max.
	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]
EES	*-17,3*	*-8,5*	*98,1*	*68,1*	*106,1*	*158,7*
noEES	*-19,4*	*-19,4*	*100,1*	*65,5*	*108,7*	*172,4*

Table 7. Electricity price statistics on H2030

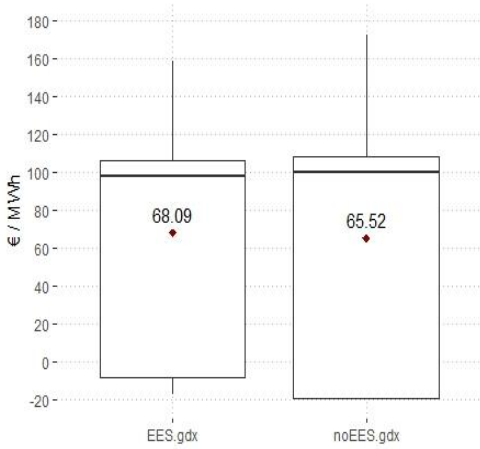

Figure 9. Boxplots of electricity prices

	Cost of Capacity obligations	RPS cost	Nuclear cap
	[€ / MW.year]	[€/%VRE]	[€/MWh]
EES	*29 649*	*7,46*	*68,76*
noEES	*44 962*	*12,92*	*65,76*

Table 8. Energy policy related costs

An unexpected result concerning the cost of the nuclear moratorium is presented in Table 8. Energy policy related costs. Storage produces an increase in the marginal cost of further decommissioning. The co-optimization of storage investments with the dispatch decisions induces load following cost and part-load efficiency savings. Given that the French nuclear capacity has been modeled with a certain amount of flexibility but with important associated costs, the presence of storage improves the operations of nuclear, hence, the value it adds to the system. When exogenously imposing a nuclear moratorium, the MWh of a more efficiently operated nuclear capacity due to EES is higher than that without it.

Storage investment also significantly reduces the cost of capacity obligations, allowing a reduction of 35.5% with respect the case when no storage is considered; least cost RPS implementation is triggered by storage by making the cost of an additional share of VRE to 7.46 €/MWh with storage versus 12.92 €/MWh without. The induced surplus variations over producers and consumers are presented in the following section.

The value of storage

Now, the value of EES investments can be assessed following the cost categories introduced in section 3.2. Figure 10 shows the variations in system costs produced by storage. There can be seen cost overruns and savings, as well as the net sum indicating its system value. The resulting net value of storage is estimated to 352.2 m€/year by 2030, which corresponds to around 1.3% of the total annualized system costs. Most of the value of storage comes from capital savings by limiting additional capital costs and mothballing costs. Storage also allows a more intensive use of existing baseload capacity characterized by lower short-run marginal cost. This is the reason why O&M costs increases with storage while generating savings on capital cost. Savings on fuel costs correspond also to a broader integration of VRE by partially avoiding curtailment. The savings on load-following and

DSM costs are rather intuitive because of the low-cost flexibility supplied by storage. Unless low short-run marginal cost but high-polluting units are pushed out of the market by regulatory obligations (binding CO_2 cap) or by market signals (effective CO_2 costs), the presence of storage is likely to intensify the usage of baseload technologies regardless its environmental impact (Carson and Novan, 2013). On this horizon, EES capacity ensures higher market shares for Hard coal than in the counterfactual case. The opposite is valid for CCGT capacity (see EOM revenues on Figure 12). This is how the CO_2 overruns are explained. Given the assumption of a flat CO_2 tax, the higher CO_2 costs mean higher CO_2 emissions.

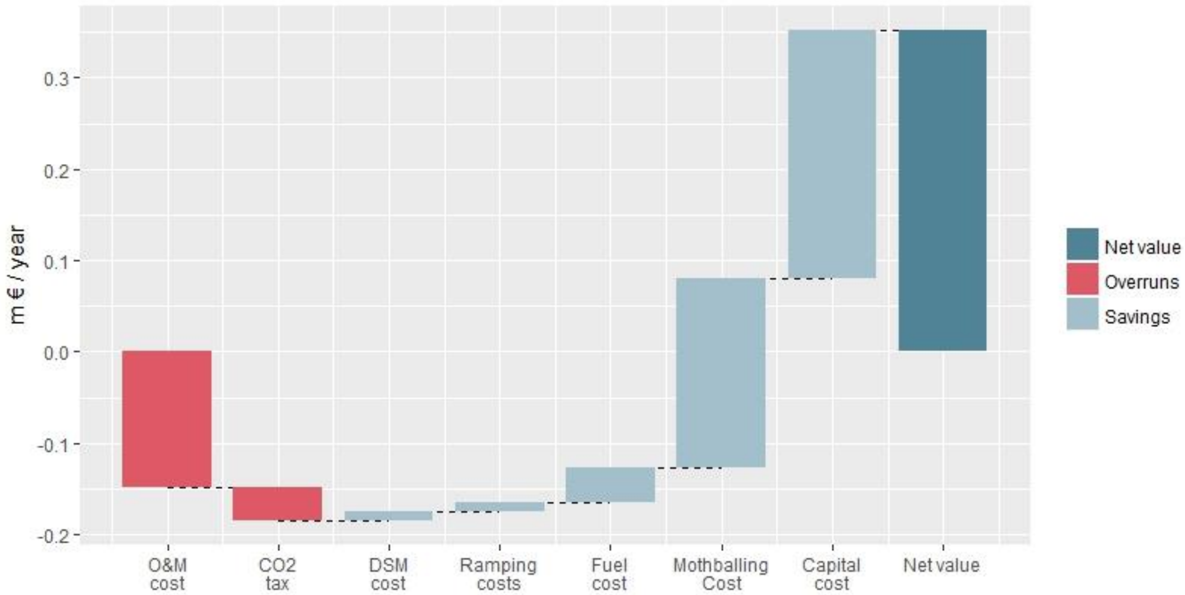

Figure 10. System value of storage investments on H2030[29]

On this framework, the system value of storage coincides with its social value. Therefore, social welfare is improved when storage is cost-optimal. Figure 10 also evidences the way the system value of storage is sparse over different cost categories. These categories are fairly outer the boundaries of the storage facilities, which suggest the presence of positive externalities generated by cost-optimal storage. Such externalities would suggest that at constant storage capacity the marginal system benefit (system value of EES) is higher than the marginal private benefits (market value of EES), which on a market driven setting would result on underinvestment, generating welfare loss due to suboptimal capacity. The latter implies policy challenges dealing with investment incentives in order to attain socially optimal investment levels.

The welfare effects of storage

Assessing the welfare effect of storage is answering to the equity question of who wins and who losses due to the distortions introduced by storage. It can be seen that since the quasi-fixed costs are optimized, the net profit of the marginal technologies should be zero. Let's see the case of OCOT

[29] O&M costs, CO_2 costs, DSM costs, load following costs (LFC), fuel costs, mothballing costs (MBC) and overnight (ON) costs.

units on the case without storage, the 11.72 GW added corresponds to the peaking units on the market.

Total costs can be calculated accounting for each of the costs categories considered on the objective function and can be classified by technology; they are illustrated in Figure 11. Investments and mothballing costs are particularly important cost categories of the system; they are incurred by endogenous decisions coming from both: economic efficiency concerns (cost-optimality) as well as regulatory obligations (RPS, nuclear share's reduction). As it was introduced to the methodology, the optimization considers equilibrium on the energy-only market (EOM), the reserve markets (FRR) and the capacity market (CRM). In such a setting, the marginal values of each of the balancing constraints correspond to the selling price of each market[30]. Therefore, the revenues of every technology can be calculated by multiplying its market shares times the marginal prices obtained for each market considered at every gate closure. The stacked revenues for every technology are presented in Figure 12.

Regarding costs, with storage, the operating costs of base load technologies slightly increases with storage, while the MBC cost of Nuclear slightly decreases because of lower decommissioning levels. Operating costs of CCGT decreases with storage is on the system due to a reduction in its market shares to the benefit of Hard-Coal. The operating costs of OCGT and OCOT also decrease when storage is available. Part of the overnight costs of OCOT and PV are saved thanks to storage investments.

The EOM revenues show a very little variation in levels for all the technologies but for Hard-Coal. This is not only the result of lower capacity retirement but also the increase of the market share of Hard-Coal. The EOM revenues of nuclear slightly decrease as a result of the decrease in its market share due to the better integration of VRE with EES. Wind and PV also increase its EOM revenues when storage is present. The revenues of Reservoir Hydro remain at the same level. Thus, the presence of storage allows for an intensified usage of low-cost marginal price technologies.

The price levels of FRR significantly decrease with storage, making the total revenues decrease. Without storage, most of the FRR revenues are captured by existing PHS, with an also some participation of Hard-Coal and Nuclear for its contribution on spinning reserve, and Hydro for the fast reserve. There is an important cost reduction on the cost of capacity credits when storage present (see Table 8). This results on an important shrink of CRM revenues, with storage taking just a part of the share but allowing existing, and less decommissioned, Nuclear to keep its shares. With storage, the total level of revenue not only shrinks but is more dependent on the EOM than without it.

It can be also highlighted in Figure 12 the specific results obtained when co-optimizing the system with existing initial capacity. This is, cumulating the revenues obtained on the three markets[31] gives just the right economic incentives to new investments to recover its variable and fixed costs. When comparing revenues with total costs for every technology on each case (see Figure 13), it can be seen how only non-decommissioned already existing capacities makes positive profits. Partially decommissioned technologies make some profits by participating in the market but also makes losses when decommissioning, as it is the case of Nuclear and Hard-Coal. The net effect depends on the market shares remaining after partial decommissioning. Meanwhile, and according to the theoretical case (Boiteux, 1951), the not binding new cost-optimal capacities show zero net profits (i.e., ACAES and OCOT), just covering their variable and fixed cost.

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[30] Assuming a market setting based on marginal pricing.

[31] Under markets with a marginal price settlement method.

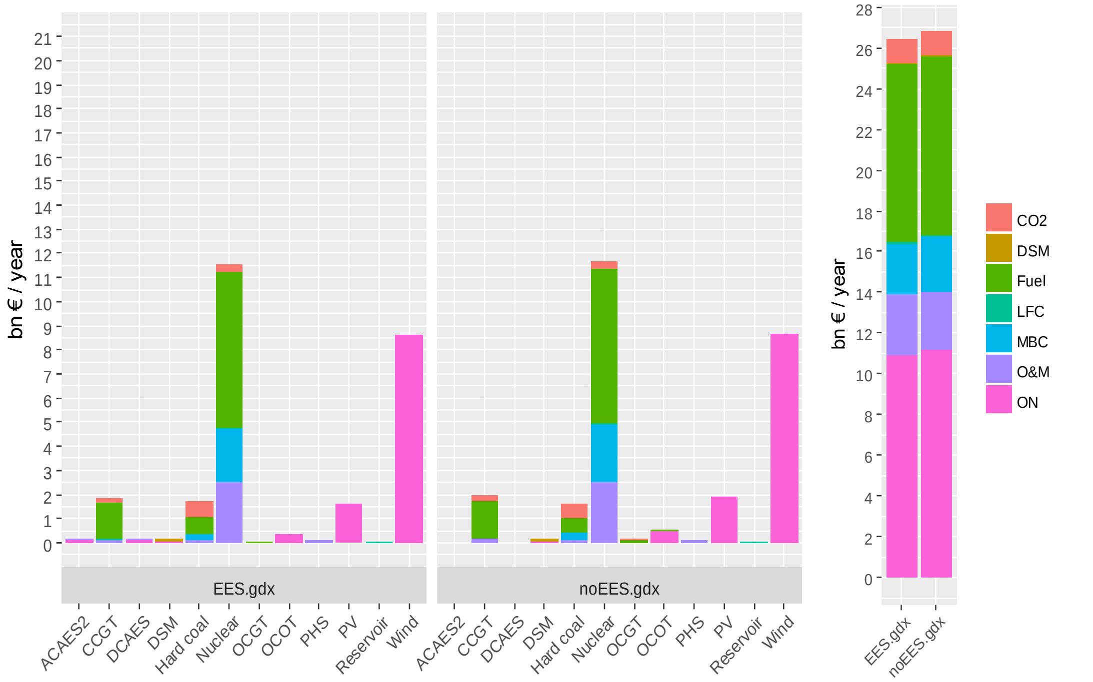


Figure 11. Cost by technology

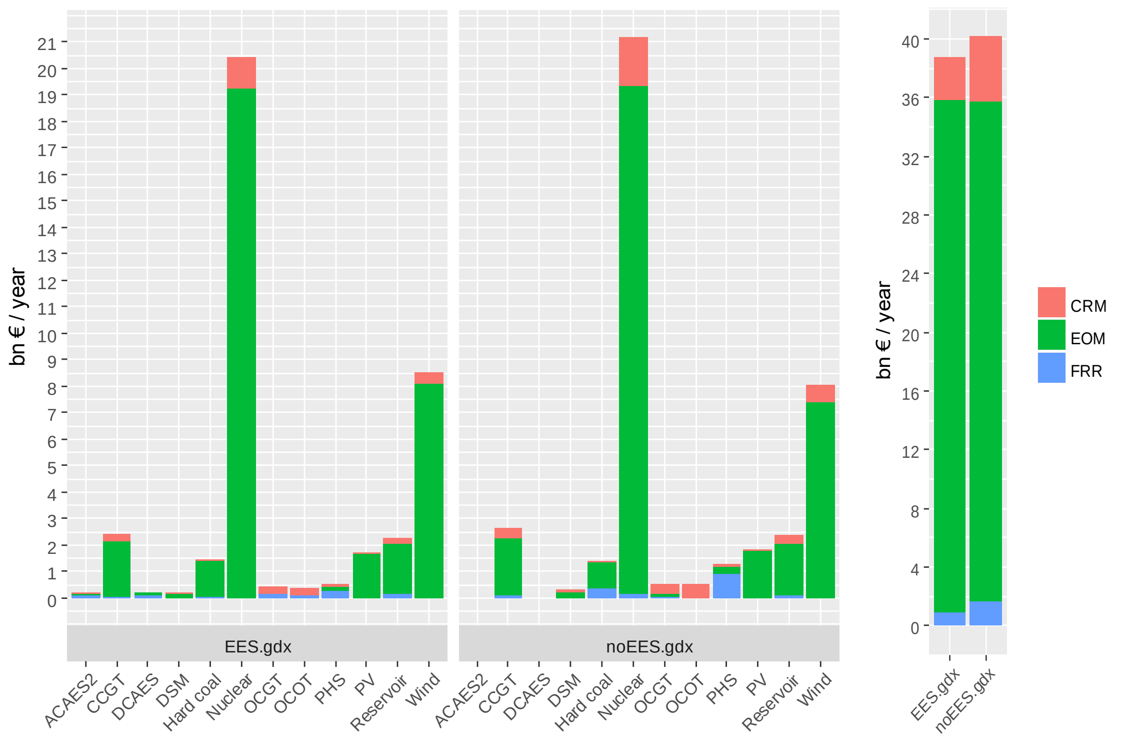


Figure 12. Revenues by technology on 2030

The case of VREs is particularly interesting: The investment levels on VRE capacity are necessary to satisfy the binding RPS targets. Thus, satisfying the RPS targets is introducing an exogenous obligation that invalid the zero-profit condition governing endogenous investments. Without storage, the total revenues of wind and solar are significantly lower than their cumulated costs. This makes an important bankability gap for renewables that should be covered by any kind of supporting scheme in order for VRE to be deployed to these levels because the market revenues are insufficient to, at least, balance their cost. EES considerably reduces this gap (see Figure 13) by increasing the market value of VRE. Less VRE investments are needed to attain the same VRE penetration targets (including VRE economic curtailment). Therefore, the social cost that of such supporting mechanism represent is reduced (see Table 8).The net effect of the entry of storage over FRR and CRM markets is to lower the prices on each of them while required quantities remain the same. As a consequence, negative surplus variations appear with respect to the counterfactual case (banning storage investments). This effect is stressed on technologies with substantial profits coming from the FRR and CRM markets.

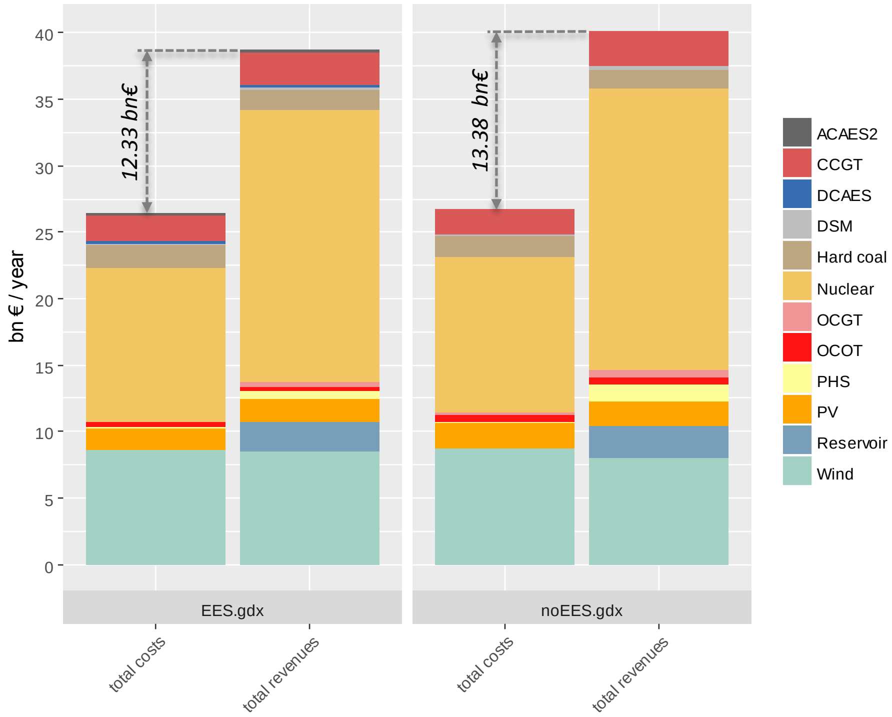


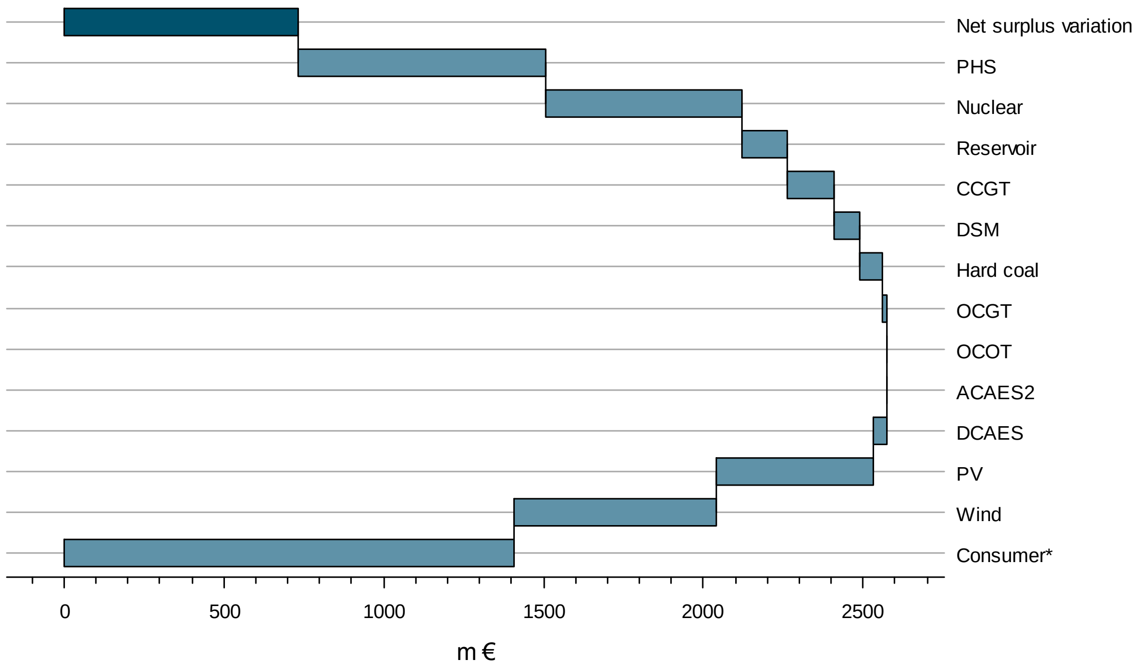
Figure 13. Revenues and costs by technology

Figure 14 presents the distribution of surplus variations produced by cost-optimal investments in EES capacity by 2030. The net surplus variation is 670 m€/year. It can be seen that surplus variations of new flexibility investments are zero[32] (OCOT and ACAES). Conventional technologies experience some surplus losses to the profit of VRE technologies due to the improvement of the VRE market value with EES. DSM experiences surplus losses due to the diminution of price-spreads and price of capacity obligations. The cumulated variation of producer's surplus is negative, which is somehow a counter-intuitive result because EES allows for a more efficient use of available resources. This is explained by a cost-effect of an enhanced "efficiency": multiservice capabilities of storage partially loosen the stringent system constraints imposed by the RPS, which lowers the revenue streams[33] of technologies compared to the counterfactual case. Given that on this horizon EES is cost-optimal, the market prices obtained on the case with banned storage represent a distortionary situation where CRM and FRR revenues are artificially inflated, which improves producer's profits. This issue would correspond to a regulatory distortion on the market by avoiding storage to participate in the capacity adequacy or reserve markets. Assuming the total cost of electricity supply, including power, capacity,

[32] The slightly positive value of DCAES surplus is determined by the constraint over the maximum potential capacity assumed for this technology (2GW).

[33] For the EOM, even if the average prices increase, the median prices decrease.

and frequency restoration services, to be completely retrofitted to consumers[34], the former experiences great saving that are traduced by surplus gains of about 1.32 bn€/year, which makes storage to unambiguously improve the overall welfare.



*Consumer's surplus variation corresponds to the no price-responsive part of load

Figure 14. Welfare effects of cost-optimal storage investments by 2030

Energy policy implications

In view of the distributional results prompt by storage, relevant ownership and regulatory issues emerge: given that profits of conventional technologies decrease with storage, investing in EES would pose a conflict of interest for utilities. Consumers and VRE generators are better off with storage[35], they would be the more concerned stakeholders for its deployment. But, can they undertake the initiatives for cost-optimal EES investments? Are them in position to do so?

- VRE producers: current supporting mechanisms based on Feed-in-tariffs (*FiT*) defines rewards upon energy generated (quantitates) regardless the state of the power system, thus, they don't give incentives for EES investments. Moreover, even under support schemes exposing VRE to market signals (e.g., Feed-in-premiums), storing energy behind the meter at VRE facility level, without a flexibility remuneration mechanism, would prevent the merit order effect to take place, eventually decreasing the price-arbitration revenues of storage and then annealing any incentive to do so. Capacity remunerations and FRR returns captured by storage would also be

[34] The part of load considered as inelastic and inflexible.

[35] Assuming perfect competitive markets.

deteriorated because of regulatory barriers and market effects, impeding these actors to undertake EES investments[36].

- Consumers: similar barriers would impede EES investments to be recovered if it is deployed behind-the-meter. But most importantly, investments in grid-level storage such as CAES technologies are out of the scope of consumers because of scale and locational reasons. Even though, assuming perfect substitution of CAES for user level batteries, electricity bills being set on the basis of average power and energy consumed would render consumers neutral to storage investments. Aggregators and dynamic pricing could be a solution for this, but still, the highly disseminated nature of consumers, problems of information asymmetry and the higher cost of capital for particulars, poses difficult coordination challenges for consumers to undertake cost-optimal EES investment and operation.
- Merchant owned storage could be urged but, under current regulatory frameworks, it would struggle to have access to all the revenue sources necessary to stack enough profits to payback investments. Risk perception would worsen the case.
- TSOs and DSOs could be the main actors to drive the uptake of storage; nevertheless, in most liberalized markets TSO and DSO are regulated participants that are not allowed to perform market-related activities. Furthermore, "their priority in the current market structure and regulatory conditions, is on quality of supply" and system reliability, "which is pursued with low risk (e.g., network capacity expansion), rather than profit maximizing strategies" (Grünewald, 2012). All of which impede any price-arbitrage usage of storage, hindering any optimal operation.

Furthermore, strategic challenges also appear when comparing the results obtained on the two horizons considered. By 2020, cost-optimal investments are composed by 4.68 GW of DSM and 15.87 GW of OCOT. While by 2030 OCOT capacity is divided almost by a half, not to mention the CCGT mothballing by 2020 and it's restoration by 2030. Considering lifespan of plants, possible dynamic inconsistencies appear between the two horizons with undesirable consequences: causing stranded OCOT capacity by 2030, causing technology lock-in situations due to the path dependency of capacity investments or having a suboptimal mix by either 2020 or 2030.

DISCUSSION

The perfect foresight assumption implemented by DIFLEXO provides an upper bound of the value of storage. Real operators, making a decision under imperfect foresight, would be able to capture just a fraction of this value. In (Sioshansi et al., 2009) it was found that an EES facility using a simple two weeks backcasting technique would get at least 85% of the revenues obtained under perfect foresight given the substantial patterns of load and prices driving close to optimal inventory utilization. For the penetration levels studied by 2020 and 2030, this conclusion still holds.

The use of more refined forecasting techniques and near-term weather forecasts would allow closing the gap between perfect and imperfect foresight cases. Even if flexibility requirements would remain with better forecasting techniques, thus, allowing for similar EOM price-arbitration revenues, there would be less need for reserve and ancillary services, decreasing the benefits of EES associated with reliability.

[36] The system view cost-optimal levels of EES investments.

Nevertheless, under even higher shares of VRE, the patterns of residual load would become less predictable. Enhanced VRE intermittency would rather benefit the case of storage technologies for risk mitigation even if its theoretical value wouldn't be achieved. In such a case, the question would be about the rationale of implementing such an ambitious RPS policy.

The consequences of abstracting from interconnections and network constraints in the study have also important implications. Interconnections are a source of flexibility that allows for locational price-arbitrations, they also offset the overall variability of VREs by combining bigger uncorrelated zones. Both effects are in detriment against the benefits of EES. Nevertheless, storage investments can also generate important savings on interconnection and T&D deferrals. Including network specificities and congestion management would add a locational dimension of the benefits of EES. An interesting point was raised by (Eyer et al., 2005) dealing with the benefits that a relocatable modular storage would have at T&D level for enhancing reliability and deferring expansion. Broadening the assessment of the value of storage to a regional landscape, integrating interconnection investments, T&D representation and country specific RPS targets are out of the scope of the present study but would be the subject of further research.

The results obtained are based on the assumption of a homothetic extrapolation of VRE generation based on the meteorological year and the installed capacity of 2015. This simplification can introduce important bias on the results. The methodology for assessing the value of storage is still valid but sensitivity analysis should be included using different years for the characterization of VRE generation and load. Other sources of uncertainty correspond to the investment cost assumed for EES technologies, the fuel, and CO2 prices expected and the DSM resource estimations.

For a broader assessment of storage benefits, the simulations were conducted without the regulatory barriers that only allow generation technologies can participate in the FRR supply. Nevertheless, other regulatory challenges appear for the cost-optimal development of storage: the system value of storage is sparse in different cost categories outside the boundaries of the storage technology, suggesting that there are external benefits (i.e., positive externalities) produced by EES investments. The latter would imply that socially optimum storage investments obtained under a system cost minimization would not necessarily correspond with that obtained from a profit maximization approach (private optimum) (see (Grünewald, 2012b) for further development of this topic); Not only the ownership structure of storage would affect its optimal usage poses regulatory issues for welfare maximization (Sioshansi, 2014, 2010), but the uptake of storage capacity would introduce asymmetric distributional effects producing winners and losers between generators creating opposing interest groups. Furthermore, the difficulties of markets to incentivize investments in storage, together with the semi-non rivalry[37] and the semi-non-excludability[38] of such kind of assets (He et al., 2011), suggest that it should be considered at least as a "near-public" good, assuming all the policy implications it implies.

The evaluation framework proposed exposes the results by giving snapshots of the optimal power system on the two horizons considered. There is no dynamic evaluation of the value of storage in between. Therefore, the question of the transition from the cost-optimal mix of 2020 to that of 2030

[37] The very low short-term marginal costs of storage makes suppose that no opportunity cost are incurred to other stakeholders using the spare storage capacity under the capacity limits.

[38] It is easily conceivable to prevent nonpayers from the usage of storage services.

has not being considered. Possible dynamic inconsistencies found when comparing results of both horizons suggest possible lack of coherence between both targets. Stranded assets situations or technology lock-in mechanisms can be created by the ambitious RPS targets imposed on the two relatively "close" horizons. These issues should be studied in a strategic framework in order to depict well-informed policy recommendations. This is also a matter of further research.

CONCLUSION

Analyzing the role of storage in power systems is a complex problem that should be analyzed in the right framework. It not only depends on its own costs but on its value related to the rest of the system. Assessing the value of storage requires a rigorous methodology and a clear definition of boundaries for accounting the multiple value sources it engenders. This study proposes practical definitions of the benefits, the value and the profits of storage units. A numerical methodology for the assessment of the value of storage has also been presented. The DIFLEXO model was proposed as the integrated tool capable of capturing competition and complementarities between different technologies when multiple services need to be balanced using high temporal resolution. The official renewable energy standards of France by 2020 and 2030 have been evaluated in order to illustrate the methodology proposed.

Relevant results are obtained for both time horizons: by 2020, 27% of VRE shares are targeted, DSM investments completely cover the higher need for flexibility; there is no storage investment, hence, no EES is cost-optimal. The value that EES creates on the system is too low related to its capital cost. Nevertheless, on the 2030 horizon, when the target of VRE share reach 40% and nuclear shares are capped from the current 75% to only 50% and further cost reductions of storage are expected, investments on compressed-air electricity storage becomes cost-optimal. In this case, storage increases the market value of VREs, reduces the operating costs of low short-run marginal units by reducing its load following costs because EES absorbs the variability of the residual load; it also provides cost-effective firm capacity and participates on reserve supply. In this scenario, the value of EES is estimated to be 352.2 m€/year and to be mainly driven by savings on capital and fuel costs. Nevertheless, at the constant CO2 tax assumed, EES produces a CO_2 emission increase of 1.8 Mton/year compared to the counterfactual case.

The average electricity price slightly increases from 65.5 €/MWh to 68.1 €/MWh with storage. It also produces a reduction of the electricity price-spread of 15.8 €/MWh. This corresponds to an asymmetric price stabilization effect over electricity prices. The asymmetry can be attributed to the efficiency loss of the power conversion system and the self-discharge characteristics of EES units, which makes it demand higher volumes of energy while charging (at low prices) than the effective amounts delivered while discharging (at high prices). Therefore, price increase during off-peak episodes is higher than price decrease during peak episodes. EES also makes the price of capacity obligations to be cut by 34%. Even with the increase in average electricity prices observed, consumer's surplus is positively affected due to the lower price of capacity obligations and ancillary services compared to the counterfactual case. The cost-effectiveness of energy policy instruments based on RPS targets would be enhanced if new flexibility technologies (such as storage) would also be considered in the directives.

Under the assumption that markets are cleared at marginal price, which secures the condition of at least zero-profit for producers, and the supply curve is co-optimized on the midterm with dispatch, the entry of storage capacity on the system entails market distortions producing winners and losers among stakeholders. It was found that VRE producers make important surplus gains with cost-optimal storage by improving its market integration levels[39] and by selling at higher average prices. On the other hand, even if revenues on the EOM market remain stable[40] for baseload conventional technologies, they experience surplus losses due to the lower revenues coming from the CRM and FRR markets as a product of additional firm capacity and ancillary services supplied from storage. The profits of peak-load conventional technologies are not particularly affected.

When assessing the value of storage on the midterm[41], only quasi-fixed costs are optimized by readjusting capital allocations, which mean that EES can generate capital savings on the marginal investments and retirement decisions. Storage cannot get its complete value because of sunk costs (initial sub-optimal capacities). It could be expected that on the long-term, assessed under a greenfield setting, equivalent EES capacity would add higher value to the system by enlarging capital cost savings.

When significant shares of VREs enter the system[42], investments in storage allow improving their market value. Careful should be paid in cases where no enough economic incentives exist for storage to counterpart low carbon intensive technologies (nuclear and VRE) because EES would enhance the usage of baseload technologies regardless its carbon footprint. Therefore, effective CO_2 cost incentives (or regulation) are required for storage to contribute to emission reduction targets: In general, EES shows complementarity with low short-run marginal cost technologies, enhancing its market shares. In the absence of an effective pricing scheme of environmental externalities (i.e., no clean spark spread or clean dark spread), cost-effective EES can also produce an increase in CO_2 emissions due to a more extensive use of coal capacity.

Results obtained show that investments in storage not only create value from different categories but also creates welfare variations across different stakeholders. Therefore, new business models for the ownership and operation of storage; advanced regulatory frameworks broadening the eligibility of storage to supply multiple services; a closer look at environmental regulation and some kind of strategic instrument would be necessary to attain the cost-optimal development of storage with in coherence with the CO_2 reduction goals. This results point out possible dynamic inconsistencies between RPS targets which would possibly cause technology lock-in situations (Schmidt et al., 2015) and/or stranded asset incidents in the mid-term.

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[39] VRE experiences lower VRE curtailment with EES.

[40] The market share loses are compensated by higher average prices.

[41] A brownfield setting to simulate the mid-term capital allocation decisions.

[42] Either because it is cost-effective or because it is imposed by exogenous targets.

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APPENDIX

A. Set, parameters and variables used by DIFLEXO

Element	Set	Description
t, tt	∈ T	Time slice
i	∈ I	Supply side generation technologies
con	∈ CON ⊆ I	Conventional generation technologies
vre	∈ VRE ⊆ I	Renewable energy technologies
ees	∈ EES ⊆ I	Electric energy storage technologies
dsm	∈ DSM	Demand-side technologies
lc	∈ LC ⊆ DSM	Demand side management able to supply load curtailment
ls	∈ LS ⊆ DSM	Demand side management able to supply load shifting

Table 9 - Sets

Parameter	Unit	Description
t_{slice}	[h]	Time slice considered
$C_i^{Capital}$	[€/GW]	Overnight cost of unit *con, res or ees*
crf_i	[€/GW]	Capacity recovery factor of unit *con*
fc_i	[€/GWh$_{th}$]	Average fuel cost by technology
$\mathrm{o\&m^{v}}_{con}$	[€/GWh]	Variable operation and maintenance cost of *con* unit
$\mathrm{o\&m^{f}}_{con}$	[€/GW]	Annual fixed operation and maintenance cost of *con* unit
C^{CO2}	[€/ton]	CO_2 cost
$\mathrm{ef_i}$	[tCO_2/GWh]	Emission factor of technology
$\mathrm{lf_{con}}$	[€/GW]	Load following cost of unit *con*
$\mathrm{o\&m^{v}}_{vre}$	[€/GWh]	Variable operation and maintenance cost of *VRE* unit
$\mathrm{o\&m^{f}}_{vre}$	[€/GW]	Annual fixed operation and maintenance cost of *RES* unit

rec_{vre}	[€/GW]	Cost of curtailment of *VRE* unit
$\mathrm{crf}^{S}{}_{vre}$	[€/GW]	Capacity recovery factor of power capacity of *ees* unit
$\mathrm{crf}^{\mathrm{E}}{}_{vre}$	[€/GWh]	Capacity recovery factor of energy capacity of *ees* unit
$\mathrm{o\&m}^{\mathrm{v}}{}_{ees}$	[€/GWh]	Variable operation and maintenance cost of *ees* unit
$\mathrm{o\&m}^{\mathrm{f}}{}_{vre}$	[€/GW]	Annualized fixed operation and maintenance cost of *ees* unit
c_{lc}	[€/GW]	Cost of DSM for load curtailment
c_{ls}	[€/GW]	Cost of DSM for load shifting
δ	[%]	Load variation factor
$\mathrm{G}^{\mathrm{l}}{}_{vre,\mathrm{t}}{}^{\mathrm{base}}$	[GW]	Base year VRE generation of technology VRE on time t
$\mathrm{P}_{vre}{}^{\mathrm{base}}$	[GW]	Base year VRE capacity installed of technology *res*
$\overline{\eta_{con}}$	[GWhth/GWh]	Full load thermal efficiency of unit con
m_{con}	[-]	Part-load efficiency slope of unit con
b_{con}	[$\mathrm{GWh_{th}}$]	Fuel consumption intercept
$\overline{\mathrm{p_{con}}}$	[%]	Maximum power of technology *con* as a function of its installed capacity
$\underline{\mathrm{p_{con}}}$	[%]	Minimum power of technology *con* as a function of its installed capacity
$r^{+}{}_{con}$	[%/min]	Ramp-up capability of technology *con*
$r^{-}{}_{con}$	[%/min]	Ramp-down capability of technology *con*
$\overline{\phi_{ees}}$	[h]	Minimum energy-power ratio of technology *ees*
$\underline{\phi_{ees}}$	[h]	Maximum energy-power ratio of technology *ees*
sd_{ees}	[%/h]	Self-discharge of storage unit *ees*
η_{ees}	[%]	Round cycle efficiency of storage unit *ees*
σ_{ees}	[%]	Fraction of discharge power coming from fuel
$\overline{e_{ees}}$	[%]	Maximum capacity for energy storage of unit *ees*
$\underline{e_{ees}}$	[%]	Minimum capacity for energy storage of unit *ees*

$\overline{s_{ees}}^{ch}$	[%]	Maximum power demand of storage unit *ees* while charging
$\overline{s_{ees}}^{dch}$	[%]	Maximum power supply of storage unit *ees* while charging
r_{ees}^{ch+}	[%/min]	Ramp-up capability of storage technology *ees* while charging
r_{ees}^{dch+}	[%/min]	Ramp-up capability of storage technology *ees* while discharging
r_{ees}^{ch-}	[%/min]	Ramp-down capability of storage technology *ees* while charging
r_{ees}^{dch-}	[%/min]	Ramp- down capability of storage technology *ees* while discharging
t_{aFRR}	[h]	Minimum required reserve supply duration for aFRR supply
t_{mFRR}	[h]	Minimum required reserve supply duration for mFRR supply
$\overline{dsm_{lc}}$	[%]	Maximum part of load available for load curtailment lc
R	[h]	Number of recovery periods after curtailment
L_{lc}	[h]	Number of consecutive periods a *lc* can be activated
L_{ls}	[h]	Radius of the load shifting window
$\overline{dsm_{ls}}^{up}$	[%]	Maximum part of load available for load upward shifting ls
$\overline{dsm_{ls}}^{do}$	[GW]	Maximum part of load available for load downward shifting *ls*
$P^{Usize}{}_{con}$	[GW]	Unitary size of conventional unit con
$\varepsilon_l^{aFRR_{up}}; \varepsilon_l^{aFRR_{do}}$	[%]	Average forecasting RMSE of demand (5% tolerance)
$\varepsilon_{res}^{aFRR_{up}}; \varepsilon_{res}^{aFRR_{do}}$	[%]	Average forecasting RMSE of VRE generation (5% tolerance)
$\varepsilon_l^{mFRR_{up}}; \varepsilon_l^{mFRR_{do}}$	[%]	Average forecasting RMSE of demand (1% tolerance)
$\varepsilon_{res}^{mFRR_{up}}; \varepsilon_{res}^{mFRR_{do}}$	[%]	Average forecasting RMSE of demand (1% tolerance)

δ^{up}	[%]	Maximum regulation up capability of technology *con*
δ^{do}	[%]	Maximum regulation down capability of technology *con*
$\delta^{up^{sp}}$	[%]	Maximum spinning up capability of technology *con*
$\delta^{do^{sp}}$	[%]	Maximum spinning down capability of technology *con*
θ_{res}	[%]	Yearly share of renewable energy (RPS)
$\theta_{nuclear}$	[%]	Nuclear share cap (nuclear moratorium)
α_i	[%]	Technology related de-rating factor for capacity value
ΔT	[°C]	Maximum temperature gap from the reference year
L_{Th}	[GW/°C]	Thermo-sensitivity of demand
SA_{req}	[%]	Residual system adequacy requirement after interconnection

Table 10 – List of parameters

Variable	Unit	Description
I_{con}	[M€]	Annuitized overnight cost of production unit *con*
MB_{con}	[M€]	Annuitized *con* unit mothballing cost
$F_{con,t}$	[M€]	Total fuel cost of production unit *con*
$O\&M_{con,t}$	[M€]	Operation and maintenance cost of conventional unit *con*
$CO2_{con,t}$	[M€]	CO2 emission cost of conventional unit *con*
$\Delta G_{con,t}$	[M€]	Load following cost of conventional unit *con*
LF_{con}	[M€]	Load following cost of unit *con*
P_i^{ini}	[GW]	Initial installed capacity of technology *i*
P_i^{inv}	[GW]	New capacity investments of technology *i*
P_i^{MB}	[GW]	Mothballed capacity of technology *i*
$G^l{}_{con,t}$	[GW]	Generation level of conventional unit *con*
$FC_{con,t}$	[GWh_{th}]	Linearized part-load fuel consumption of production unit con
$G^+{}_{con,t}$	[GW]	Generation increase of unit *con* in hour *t*
$G^-{}_{con,t}$	[GW]	Generation decrease of unit *con* in hour *t*
I_{vre}	[M€]	Annuitized overnight cost of VRE unit *res*
MB_{vre}	[M€]	Annuitized VRE mothballing cost
$O\&M_{vre,t}$	[M€]	Operation and maintenance cost of RE unit *res*
P_{vre}	[GW]	Total installed power of VRE units
$G^l{}_{vre,t}$	[GW]	Generation level of VRE unit *res*
$REC_{vre,t}$	[M€]	Curtailment cost of VRE unit *res*
$G_{vre,t}^{cu}$	[GW]	Power curtailed of V*RE* unit on hour *t*
I_{ees}	[M€]	Annuitized overnight cost of storage unit *ees*
MB_{ees}	[M€]	Annuitized *ees* mothballing cost
$O\&M_{ees,t}$	[M€]	Operation and maintenance cost of *ees* units
S_{ees}^{ini}	[GW]	Initial installed power capacity of storage technology *ees*

S_{ees}^{inv}	[GW]	New power capacity investments of storage technology *ees*
S_{ees}^{MB}	[GW]	Mothballed power capacity of storage technology *ees*
E_{ees}^{ini}	[GW]	Initial installed energy capacity of storage technology *ees*
E_{ees}^{inv}	[GW]	New power energy investments of storage technology *ees*
E_{ees}^{MB}	[GW]	Mothballed energy capacity of storage technology *ees*
$S_{ees,t}^{ch}$	[GW]	Power demand by storage unit *ees* on time t
$S_{ees,t}^{dch}$	[GW]	Power supply by storage unit *ees* on time t
$S_{ees,t}^{ch+}$	[GW/h]	Demand increase of storage unit *ees* in hour *t* while charging
$S_{ees,t}^{ch-}$	[GW/h]	Supply increase of storage unit *ees* in hour *t* while charging
$S_{ees,t}^{dch+}$	[GW/h]	Demand increase of storage unit *ees* in hour *t* while discharging
$S_{ees,t}^{dch-}$	[GW/h]	Supply increase of storage unit *ees* in hour *t* while discharging
${E^l}_{ees,t}$	[GW]	Storage level of technology ees
$DSM_{lc,t}$	[GW]	Hourly cost of DSM for load curtailment
${DSM^l}_{lc,t}$	[GW]	DSM curtailment of load *lc* on time t
$DSM_{ls,t}$	[GW]	Hourly cost of DSM for load Shifting
$DSM_{ls,t}^{up}$	[GW]	DSM shifting up *ls* on time t
$DSM_{ls,t,tt}^{do}$	[GW]	DSM shifting up *ls* on time *tt* from *t*
NL_t	[GW]	Net load on time t
LL_t	[GW]	Loss of load on time t
$G_{con,t}^{aFRR_{up}}$	[GW]	Contribution of *con* units to $mFRR$ up supply
$G_{con,t}^{aFRR_{do}}$	[GW]	Contribution of *con* unit to $aFRR$ down supply
$G_{con,t}^{mFRR_{up}^{sp}}$	[GW]	Contribution of spinning *con* unit to $mFRR$ up supply
$G_{con,t}^{mFRR_{do}^{sp}}$	[GW]	Contribution of spinning *con* unit to $mFRR$ down supply
$G_{con,t}^{mFRR_{up}^{nsp}}$	[GW]	Contribution of non-spinning *con* unit to $mFRR$ up supply

$S_{ees,t}^{ch,aFRR_{up}}$	[GW]	Contribution of *ees* unit to $aFRR$ up supply while charging
$S_{ees,t}^{ch,mFRR_{up}}$	[GW]	Contribution of *ees* unit to $mFRR$ up supply while charging
$S_{ees,t}^{ch,aFRR_{do}}$	[GW]	Contribution of *ees* unit to $aFRR$ down supply while charging
$S_{ees,t}^{ch,mFRR_{do}}$	[GW]	Contribution of *ees* unit to $mFRR$ down supply while charging
$S_{ees,t}^{dch,aFRR_{up}}$	[GW]	Contribution of *ees* unit to $aFRR$ up supply while discharging
$S_{ees,t}^{dch,mFRR_{up}}$	[GW]	Contribution of *ees* unit to $mFRR$ up supply while discharging
$S_{ees,t}^{dch,aFRR_{do}}$	[GW]	Contribution of *ees* unit to $aFRR$ down supply while discharging
$S_{ees,t}^{dch,mFRR_{do}}$	[GW]	Contribution of *ees* unit to $mFRR$ down supply while discharging
$Q_t^{aFRR_{up}}$	[GW]	Total *aFRR* up required on time *t*
$Q_t^{aFRR_{do}}$	[GW]	Total *aFRR* down required on time *t*
$Q_t^{mFRR_{up}}$	[GW]	Total *mFRR* up required on time *t*
$Q_t^{mFRR_{do}}$	[GW]	Total *mFRR* down required on time *t*

Table 11 – List of variables

Equations of the DIFLEXO model used in the calculations

$$\begin{aligned} Y = & \sum_{con}(I_{con} + MB_{con}) + \sum_{con}\sum_{t}\left(F_{con,t} + O\&M_{con,t} + CO2_{con,t} + \Delta G_{con,t}\right) \\ & + \sum_{vre}(I_{vre} + MB_{vre}) + \sum_{res}\sum_{t}\left(O\&M_{vre,t} + VREC_{vre,t}\right) \\ & + \sum_{ees}(I_{ees} + MB_{ees}) + \sum_{ees}\sum_{t}\left(O\&M_{ees,t} + CO2_{ees,t}\right) \\ & + \sum_{DSM} I_{DSM} + \sum_{lc}\sum_{t} O\&M_{lc,t}^{DSM} + \sum_{ls}\sum_{t} O\&M_{ls,t}^{DSM} \end{aligned} \tag{1}$$

Cost related equations:

$$I_i = crf_i \, P_i^{inv} \qquad \forall\, i \neq ees \tag{2}$$

$$crf_i = \frac{WACC_i \, C_i^{Capital}}{1 - \left(\frac{1}{1 + WACC_i}\right)^{a_i^{life}}} \qquad \forall\, i \tag{3}$$

$$I_{ees} = crf^S{}_{ees} \, S_{ees}^{inv} + crf^E{}_{ees} E_{ees}^{inv} \qquad \forall\; ees \tag{4}$$

$$S_{ees} \underline{\phi_{ees}} \leq E_{ees} \leq S_{ees} \overline{\phi_{ees}} \qquad \forall\; ees \tag{5}$$

$$I_{DSM} = crf_{DSM} \; DSM \qquad \forall\; ees \tag{6}$$

$$MB_i = 0.05 \, C_i^{Capital} P_i^{MB} \qquad \forall\; i \tag{7}$$

$$F_{con,t} = Fuel_{con,t} \, fc_{con} \qquad \forall\; con \tag{8}$$

$$O\&M_{i,t} = o\&m^v{}_i \;\; G^l{}_{con,t} + o\&m^f{}_i \, P_i \qquad \forall\; i \tag{9}$$

$$CO2_{con,t} = C^{CO2} \;\; ef_{con} \, Fuel_{con,t} \qquad \forall\; con \tag{10}$$

$$\Delta G_{con,t} = \left| \, G^l{}_{con,t} - G^l{}_{con,t-1} \right| lf_{con} \qquad \forall\; con \tag{11}$$

$$MB_{ees} = 0.05 \left(C_{ees}^{Capital,S} \;\; S_{ees}^{MB} \; + \; C_{ees}^{Capital,P} E_{ees}^{MB} \right) \qquad \forall\; ees \tag{12}$$

$$O\&M_{ees,t} = o\&m^v{}_{ees} \left(S_{ees,t}^{ch} + S_{ees,t}^{dch} \right) + \sigma_{ees} \, \frac{S_{ees,t}^{dch}}{\eta_{fuel}} \, fc_{ees} + \; o\&m^f{}_{ees} \, S_{ees} \qquad \forall\, ees, t \tag{13}$$

$$CO2_{ees,t} = C^{CO2} \;\; ef_{ees} \, \alpha_{ees} \, \frac{S_{ees,t}^{dch}}{\eta_{ees}} \tag{14}$$

$$REC_{vre,t} = G^{cu}_{vre,t}\; rec_{vre} \qquad \forall\ vre \qquad (15)$$

$$Fuel_{con,t} = G^{l}{}_{con,t}\; m_{con} + b_{con} \qquad \forall\ con \qquad (16)$$

$$m_{con} = \frac{\Delta FC^{max}_{con}}{\Delta P^{max}_{con}} = \frac{\frac{P_{con}\,\overline{p_{con}}}{\overline{\eta_{con}}} - \frac{P_{con}\,\underline{p_{con}}}{\underline{\eta_{con}}}}{P_{con}\,\overline{p_{con}} - P_{con}\,\underline{p_{con}}} = \frac{\frac{\overline{p_{con}}}{\overline{\eta_{con}}} - \frac{\underline{p_{con}}}{\underline{\eta_{con}}}}{\left(\overline{p_{con}} - \underline{p_{con}}\right)} \qquad \forall\ con \qquad (17)$$

$$b_{con} = \left(\frac{\overline{p_{con}}}{\overline{\eta_{con}}} - m_{con}\,\overline{p_{con}}\right) P_{con} \qquad \forall\ con \qquad (18)$$

$$Fuel_{con,t} = \left(G^{l}{}_{con,t} - \overline{p_{con}}\,P_{con}\right) m_{con} + P_{con}\frac{\overline{p_{con}}}{\overline{\eta_{con}}} \qquad \forall\ con \qquad (19)$$

$$O\&M^{DSM}_{lc,t} = DSM^{l}{}_{lc,t}\; o\&m_{lc} \qquad \forall\, t, lc \qquad (20)$$

$$O\&M^{DSM}_{ls,t} = DSM^{up}_{ls,t}\; o\&m_{ls} \qquad \forall\, t, ls \qquad (21)$$

$$G^{l}{}_{vre,t} = \frac{{G^{l}{}_{vre,t}}^{base}}{{P_{vre}}^{base}}\left(P^{ini}_{vre} + P^{inv}_{vre} - P^{MB}_{vre}\right) \qquad \forall\, vre, t \qquad (22)$$

EOM market equilibrium:

$$NL_t = L^{base}_t\,(1+\delta) - \sum_{vre}\left(G^{l}_{vre,t} - G^{cu}_{vre,t}\right) \qquad \forall\, t \qquad (23)$$

$$NL_t = \sum_{con} G^{l}{}_{con,t} + \sum_{ees}\left(S^{dch}_{ees,t} - S^{ch}_{ees,t}\right) + \sum_{lc} DSM^{l}{}_{lc,t} + \sum_{ls}\sum_{tt=t-L_{ls}}^{tt=t+L_{ls}} DSM^{do}_{ls,tt,t} - \sum_{ls} DSM^{up}_{ls,t} \qquad \forall\, t \qquad (24)($$

FRR market equilibrium:

$$Q_t^{aFRR_{up}} = \varepsilon_l^{aFRR_{up}} \, L_t^{base} \, (1+\delta) + \sum_{vre} \varepsilon_{vre}^{aFRR_{up}} \, P_{vre} \qquad \forall\, t \tag{25}$$

$$Q_t^{aFRR_{do}} = \varepsilon_l^{aFRR_{do}} \, L_t^{base} \, (1+\delta) + \sum_{vre} \varepsilon_{vre}^{aFRR_{do}} \, P_{vre} \qquad \forall\, t \tag{26}$$

$$Q_t^{mFRR_{up}} = \varepsilon_l^{mFRR_{up}} \, L_t^{base} \, (1+\delta) + \sum_{vre} \varepsilon_{vre}^{mFRR_{up}} \, P_{vre} \qquad \forall\, t \tag{27}$$

$$Q_t^{mFRR_{do}} = \varepsilon_l^{mFRR_{do}} \, L_t^{base} \, (1+\delta) + \sum_{vre} \varepsilon_{vre}^{mFRR_{do}} \, P_{vre} \qquad \forall\, t \tag{28}$$

$$\sum_{con} G_{con,t}^{aFRR_{up}} + \sum_{ees} \left(S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{dch,aFRR_{up}} \right) = Q_t^{aFRR_{up}} \qquad \forall\, t \tag{29}$$

$$\sum_{con} G_{con,t}^{aFRR_{do}} + \sum_{ees} \left(S_{ees,t}^{ch,aFRR_{do}} + S_{ees,t}^{dch,aFRR_{do}} \right) = Q_t^{aFRR_{do}} \qquad \forall\, t \tag{30}$$

$$\sum_{con} \left(G_{con,t}^{mFRR_{up}^{sp}} + G_{con,t}^{mFRR_{up}^{nsp}} \right) + \sum_{ees} \left(S_{ees,t}^{ch,mFRR_{up}} + S_{ees,t}^{dch,mFRR_{up}} \right) = Q_t^{mFRR_{up}} \qquad \forall\, t \tag{31}$$

$$\sum_{con} G_{con,t}^{mFRR_{do}^{sp}} + \sum_{ees} \left(S_{ees,t}^{ch,mFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \right) = Q_t^{mFRR_{do}} \qquad \forall\, t \tag{32}$$

Capacity market equilibrium (CRM):

$$CA = SA_{req}\ \left(\max\left(L_t^{base}\ (1+\delta)\right) + L_{Th}\,\Delta T\right) \tag{33}$$

$$CA\ \leq\ \sum_{con} P_{con}\,\alpha_{con} + \sum_{ees} S_{ees}\,\alpha_{ees} + \sum_{vre} P_{vre}\,\alpha_{vre}\,cf_{vre} + \sum_{ls,lc} DSM\,\alpha_{dsm} \tag{34}$$

Operating constraints of conventional technologies:

$$P_{con} = P_{con}^{ini} + P_{con}^{inv} - P_{con}^{MB} \qquad \forall\ con \tag{35}$$

$$G^{l}{}_{con,t} + G_{con,t}^{aFRR_{do}} + G_{con,t}^{mFRR_{do}^{sp}}\ \leq\ \overline{p_{con}}P_{con} \qquad \forall\ con, t \tag{36}$$

$$\underline{p_{con}}P_{con} \leq\ G^{l}{}_{con,t} - G_{con,t}^{aFRR_{up}} - G_{con,t}^{mFRR_{up}^{sp}} \qquad \forall\ con, t \qquad \forall\ con, t \tag{37}$$

$$\Delta G^{l}{}_{con,t} + G_{con,t}^{aFRR_{do}} + G_{con,t}^{mFRR_{do}^{sp}} \leq\ G_{con,t}^{+} \qquad \forall\ con, t \qquad \forall\ con, t \tag{38}$$

$$-G^{-}{}_{con,t}\ \leq \Delta G^{l}{}_{con,t} + G_{con,t}^{aFRR_{up}} + G_{con,t}^{mFRR_{up}^{sp}} \qquad \forall\ con, t \qquad \forall\ con, t \tag{39}$$

$$H2O_w^l = \frac{H2O_w^{avg}}{\overline{P_{hydro}}}\ P_{hydro} + \frac{H2O_w^{inflow}}{\overline{P_{hydro}}} P_{hydro}\ - \sum_{t\,\in\,w} Fuel_{hydro,t} \qquad if\quad w = 1 \tag{40}$$

$$H2O_w^l - H2O_{w-1}^l = \frac{H2O_w^{inflow}}{\overline{P_{hydro}}} P_{hydro}\ - \sum_{t\,\in\,w} Fuel_{hydro,t} \qquad if\quad w > 1 \tag{41}$$

(42)

$$\underline{H2O} < H2O_w^l \leq \overline{H2O} \qquad \forall\ w$$

EES related constraints:

$$E_{ees} = E_{ees}^{ini} + E_{ees}^{ini} - E_{ees}^{MB} \qquad \forall\ ees \qquad (43)$$

$$S_{ees} = S_{ees}^{ini} + S_{ees}^{ini} - S_{ees}^{MB} \qquad \forall\ ees \qquad (44)$$

$$E^l{}_{ees,t} = E^l{}_{ees,t-1}\,(1 - sd_{ees}) + \left(\sqrt{\eta_{ees}}\ S_{ees,t-1}^{ch,} - \frac{S_{ees,t-1}^{dch}}{\sqrt{\eta_{ees}}}\right) t_{slice} \qquad \forall\ t,\ ees \qquad (45)$$

$$\underline{e_{ees}}\, E_{ees} \leq\ E^l{}_{ees,t} \leq \overline{e_{ees}}\, E_{ees} \qquad \forall\ t,\ ees \qquad (46)$$

$$S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \leq S_{ees}\ \overline{s_{ees}}^{ch} - S_{ees,t}^{ch} \qquad \forall\ t,\ ees \qquad (47)$$

$$S_{ees,t}^{ch,aFRR_{do}} + S_{ees,t}^{ch,mFRR_{do}} \leq S_{ees,t}^{ch} \qquad \forall\ t,\ ees \qquad (48)$$

$$S_{ees,t}^{dch,aFRR_{up}} + S_{ees,t}^{dch,mFRR_{up}} \leq S_{ees,t}^{dch} \qquad \forall\ t,\ ees \qquad (49)$$

$$S_{ees,t}^{dch,aFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \leq\ S_{ees}\ \overline{s_{ees}}^{dch} - S_{ees,t}^{dch} \qquad \forall\ t,\ ees \qquad (50)$$

$$S_{ees,t}^{ch} + S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \leq\ S_{ees}\ \overline{s_{ees}}^{dch} \qquad \forall\ t,\ ees \qquad (51)$$

$$S_{ees,t}^{dch} + S_{ees,t}^{dch,aFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \leq\ S_{ees}\ \overline{s_{ees}}^{ch} \qquad \forall\ t,\ ees \qquad (52)$$

$$\Delta S_{ees,t}^{ch} + S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \leq\ S_{ees,t}^{ch+} \qquad \forall\ t,\ ees \qquad (53)$$

$$-S_{ees,t}^{ch-} \leq\ \Delta S_{ees,t}^{ch} + S_{ees,t}^{ch,aFRR_{do}} + S_{ees,t}^{ch,mFRR_{do}} \qquad \forall\ t,\ ees \qquad (54)$$

$$\Delta S_{ees,t}^{dch} + S_{ees,t}^{dch,aFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \leq S_{ees,t}^{dch+} \qquad \forall\, t, ees \qquad (55)$$

$$-S_{ees,t}^{dch-} \leq \Delta S_{ees,t}^{dch} + S_{ees,t}^{dch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \qquad \forall\, t, ees \qquad (56)$$

$$S_{ees,t}^{ch+} = r_{ees}^{ch+}\, S_{ees}\, 60\, t_{slice} \qquad \forall\, t, ees \qquad (57)$$

$$S_{ees,t}^{dch+} = r_{ees}^{dch+}\, S_{ees}\, 60\, t_{slice} \qquad \forall\, t, ees \qquad (58)$$

$$S_{ees,t}^{ch-} = r_{ees}^{ch-}\, S_{ees}\, 60\, t_{slice} \qquad \forall\, t, ees \qquad (59)$$

$$S_{ees,t}^{dch-} = r_{ees}^{dch-}\, S_{ees}\, 60\, t_{slice} \qquad \forall\, t, ees \qquad (60)$$

$$\left(S_{ees,t}^{ch}\, t_{slice}\right)\sqrt{\eta_{ees}} \leq E_{ees} - {E^{l}}_{ees,t-1} \qquad \forall\, t, ees \qquad (61)$$

$$\frac{S_{ees,t}^{dch}\, t_{slice}}{\sqrt{\eta_{ees}}} \leq {E^{l}}_{ees,t-1} \qquad \forall\, t, ees \qquad (62)$$

$$\left[S_{ees,t}^{ch}\, t_{slice} + S_{ees,t}^{ch,aFRR_{do}}\, t_{aFRR} + S_{ees,t}^{ch,mFRR_{do}}\, t_{mFRR}\right]\sqrt{\eta_{ees}} \leq E_{ees} - {E^{l}}_{ees,t} \qquad \forall\, t, ees \qquad (63)$$

$$\left[S_{ees,t}^{dch}\, t_{slice} + S_{ees,t}^{dch,aFRR_{up}}\, t_{aFRR} + S_{ees,t}^{dch,mFRR_{up}}\, t_{mFRR}\right]\frac{1}{\sqrt{\eta_{ees}}} \leq {E^{l}}_{ees,t} \qquad \forall\, t, ees \qquad (64)$$

DSM related constraints:

$$0 \leq {DSM^{l}}_{lc,t} \leq \overline{dsm}_{lc}\; L_{t}^{base}\,(1+\delta) \qquad \forall\, t, lc \qquad (65)$$

$$\sum_{tt=0}^{R-1} DSM^{l}{}_{lc,t+tt} \leq \overline{dsm}_{lc}\;\; L_t^{base}\,(1+\delta)\, L_{lc} \qquad \forall\, t, lc$$ $\forall\, t, lc$ *(66)*

$$DSM_{ls,t}^{up} = \sum_{tt=t-L_{ls}}^{t\,+\,L_{ls}} DSM_{ls,t,tt}^{do}$$ $\forall\, t, ls$ *(67)*

$$DSM_{ls,t}^{up} \leq \;\overline{dsm}_{ls}^{up}\;\, L_t^{base}\,(1+\delta)$$ $\forall\, t, ls$ *(68)*

$$DSM_{ls,t}^{up} \;+ \sum_{tt=t-L_{ls}}^{tt=t\,+\,L_{ls}} DSM_{ls,t,tt}^{do} \leq max\left(\overline{dsm}_{ls}^{up}\,;\overline{dsm}_{ls}^{do}\right) L_t^{base}\,(1+\delta)$$ $\forall\, t, ls$ *(69)*

$$DSM^{l}{}_{lc,t} + DSM_{ls,t}^{up} \;+ \sum_{tt=t-L_{ls}}^{tt=t\,+\,L_{ls}} DSM_{ls,t,tt}^{do} \leq DSM$$ $\forall\, t, lc, ls$ *(70)*

Energy policy constraints

VRE shares:

$$\sum_{t}\sum_{con\neq hydro} G_{con,t}^{l} \leq \left(\frac{1-\theta_{vre}}{\theta_{vre}}\right)\left[\sum_{t}\sum_{vre}\,(G^{l}{}_{vre,t} - \,G_{vre,t}^{cu}) + \sum_{t}\, G^{l}{}_{hydro,t}\right]$$ *(71)*

Nuclear moratorium:

$$\sum_{t} G_{nuclear,t}^{l} \leq \left(\frac{1-\theta_{con}}{\theta_{con}}\right)\left[\sum_{t}\sum_{vre}\,(G^{l}{}_{vre,t} - \,G_{vre,t}^{cu}) + \sum_{t}\sum_{con\neq nuclear} G_{con,t}^{l}\right]$$ if $con = nuclear$ *(72)*

$$P_{con}^{inv} = P_{con}^{MB}$$ if $con = nuclear$ *(73)*

B. Technical parameters of storage technologies

Technology	*EES Emin* [%]	*Chg ramp* [% S/h]	*Dchg ramp* [% S/h]	*Auth_min* [h]	*Auth_max* [h]	*Self_dch* [% E/h]	*Efficiency* [%]	*Derating factor*
Li-ion	*20%*	*100%*	*100%*	*1*	*3*	*0,0167%*	*90%*	*86%*
NaS	*10%*	*100%*	*100%*	*1*	*7*	*0,8333%*	*83%*	*86%*
VRFB	*10%*	*100%*	*100%*	*1*	*8*	*0,0004%*	*78%*	*86%*
PHS	*10%*	*100%*	*100%*	*1*	*8*	*0,0000%*	*76%*	*54%*
DCAES	*15%*	*100%*	*100%*	*1*	*6*	*0,0004%*	*90%*	*54%*
Flywheel	*-*	*100%*	*100%*	*1*	*1,5*	*4,1667%*	*94%*	*-*
Lead_acid	*20%*	*100%*	*100%*	*1*	*3*	*0,0083%*	*80%*	*86%*
ACAES	*20%*	*100%*	*100%*	*1*	*12*	*0,0004%*	*90%*	*54%*

C. Technical parameters of generation technologies

Technology	*Efficiency* [%]	*Pmin* [%]	*Pmax* [%]	*Ramp up* [%/m]	*Ramp down* [%/m]	*Reg up* [%/m]	*Reg down* [%/m]	*Eff loss*	*M eff*	*Derating factor*
Nuclear	*32%*	*0,5*	*1*	*5%*	*5%*	*2,5%*	*2,5%*	*0,24*	*2,30*	*0,84*
Hard coal	*47%*	*0,4*	*1*	*4%*	*4%*	*2,0%*	*2,0%*	*0,06*	*1,95*	*0,87*
CCGT	*62%*	*0,3*	*1*	*4%*	*6%*	*2,0%*	*3,0%*	*0,072*	*1,95*	*0,88*
OCOT	*34%*	*-*	*1*	*8%*	*8%*	*4,0%*	*4,0%*	*0,013*	*2,94*	*0,94*
OCGT	*39%*	*-*	*1*	*25%*	*25%*	*12,5%*	*12,5%*	*0,06*	*2,56*	*0,94*
Reservoir	*90%*	*-*	*1*	*10%*	*10%*	*5,0%*	*5,0%*	*-*	*1,11*	*0,86*