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Adrienne De Bazelaire, Kutluhan Pak, Yannick Perez, Vincent Rious. Grid expansion planning with battery storage: Economic potential under high renewable penetration. *The Electricity Journal*, 2024, 37, <10.1016/j.tej.2024.107419>. <hal-04828232>

HAL Id: hal-04828232

<https://hal.science/hal-04828232v1>

Submitted on 9 Dec 2024

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Grid expansion planning with battery storage: Economic potential under high renewable penetration

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ARTICLE INFO

Keywords:

Power grid
Expansion planning
Battery storage

ABSTRACT

To ensure a smooth energy transition, rapid expansion of the electric grid is essential to accommodate growing renewable power generation. We assess the role battery storage can play for the power system by either complementing or replacing costly line reinforcements. Adopting a benevolent planner point-of-view, we optimise the expansion of storage with the grid. We focus on a discrete representation of the sub-transmission grid. Given high reinforcement costs and efficient batteries, storage could replace grid investments, especially during low energy prices periods. Additionally, adopting a cost-effective grid representation minimizes storage investments. Ultimately, our work aims to empower grid operators to efficiently utilize battery storage in planning grid expansion.

1. Introduction

Due to climate change mitigation policies in line with the COP 28, the power grid must rapidly adapt to the system's transition from fossil fuels to Renewable Energy Sources (RES). In France, around 10 GW of photovoltaic power (PV) are installed in 2023; by 2050, there could be up to 200 GW. Large addition of RES to the grid progressively saturates the available connection capacity by overtaking the grid development pace and causing overloads of existing power lines. According to the IEA, grid operators must invest heavily in grid infrastructures to accommodate new renewable generation (International Energy Agency, 2023). The French transmission grid operator plans on investing between 200 and 1200 million euros per year to expand the transmission grid by 2035 (RTE, 2019, chap. 3).

In European countries, a RES power plant owner often bears the connection cost (ENTSO-e, 2020). Since the connection fee increases with the voltage level, owners tend to connect to the lower-voltage grids (CEER et al., 2005, tbl. 5; Gans and King, 2003, tbl. 5). As the available connection capacity on low-voltage grids is progressively saturated, RES owners increasingly turn to higher voltage grids such as the sub-transmission grid (sub-transmission here refers to a meshed medium voltage grid between distribution and transmission grids (MIT, 2016; PJM, 2013, p. 11)).

In this context, energy storage appears as a silver bullet solution to

avoid large capex-intensive grid investments by deferring grid reinforcement and reducing RES curtailment (MIT, 2022). Energy storage can store excess power during congestion periods and reinject the stored energy later once the congestion has resolved. While reinforcing a line requires large and bulky investments, battery storage can be installed in small capacities tailored to meet local grid needs. In some circumstances, storage could reduce the overall expansion cost, especially when facing intermittent congestions below the capacity level of a reinforcement.

Traditionally, grid operators use optimisation models or heuristic-based approaches to plan their expansion. These methods traditionally exclude storage and, more broadly, all generation assets from the expansion solution panels. Since grid operators are prohibited from owning or operating any for regulatory reasons, their expansion reacts to a fixed-generation expansion plan. It is called "reactive planning" or "generation-first". These reactive methods ignore the trade-offs between generation and transmission investment plans: the siting and sizing of generation investments impact the transmission lines' siting and sizing, and conversely. This issue can be addressed by using co-optimisation techniques to capture benefits from simultaneously planning both generation and transmission.

Battery storage plays on both generation and transmission sides: On the generation side, it switches load through time, and on the grid side, it reduces local congestion. We need to optimise both generation and

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transmission to study how useful batteries could be for grid expansion planning. We co-optimize storage and grid investments with storage dispatch. By planning simultaneously both, storage can be valued for shifting generation and replacing reinforcement while respecting grid constraints. In this paper, we adopt the point-of-view of a grid operator, who includes storage along reinforcement as a solution and must adapt to exogenous generation additions. While grid operators are usually prohibited from owning storage assets, they could enter into a contract with a private operator to have storage managing congestion in exchange of a capacity deferral remuneration (Poudineh and Jamasb, 2014).

Here, we will focus on the sub-transmission grid, which is undergoing rapid and high renewable penetration. Since battery storage usually stores electricity for a maximum of a dozen hours, our study focuses on solar power plants. Generation and grid expansion models tend to favour solar over wind investments (Manocha et al., 2023), probably because solar is more predictable (it generates electricity on a daily pattern) and congestions associated last no more than half a day (while wind can generate power for several consecutive days).

Our paper is structured as follows: Section 2 reviews a grid operator's solutions to expand the grid capacities. We review models that include some of the non-grid alternative solutions in the optimisation modelling, such as Demand Side Response, Electric Vehicles or Battery Storage. In Section 3, we present our methodology. We set our model, system, parameters, hypothesis, and optimisation functions (network representation, power flow representation, decision variables, time representation, study horizon, deterministic considerations). In Section 4, our first experiment helps us identify the complementarity dynamics of grid and storage under various cost scenarios. Our second experiment observes the impact of line lumpiness on storage. Section 5 discusses our results and infers key determinants of storage value for the grid expansion. Section 6 discusses potential future work on multi-horizon planning and uncertainty on RES development rhythm and spread.

2. Literature review

Transmission and Distribution System Operators (TSO, DSO) face increasing congestions linked to additional connections of renewables to the grid (RTE, 2019, chap. 10). The integration of growing renewables leads to a significant rise in short-term operation costs, as observed for instance in Germany and Great Britain (Joos and Staffell, 2018).

When facing minor congestions, grid operators can increase the existing grid flexibility with various short-term solutions. Examples of short-term solutions include among others the Dynamic Line Rating. It provides real-time monitoring of a line transit given local meteorological conditions: cool and windy conditions improve line thermal capacities. A second tool are Topology Automats. They temporarily reconfigure the grid's topology to modify loop flows and alleviate localised congestion. Another is Curtailment automats that curb renewable power plants' outputs when exceeding the grid capacity.

These solutions provide the grid operator with marginal and temporary capacity upgrades. On a longer-term perspective, grid operators expand the grid capacity with investments: building a new line or adding a parallel line (reinforcement), upgrading the line and bus voltage, or restructuring the topology. These "grid-side" solutions can be complemented by "non-grid" solutions such as Demand Side Response (DSR), Electric Vehicles (EV) and battery storage, which can also provide alternatives to traditional grid expansion (Astier et al., 2021).

The EU Directive 2009/72/EC requires the unbundling of the electric industry, thus forbidding grid operators from owning or operating storage and generation assets. Instead, grid operators can contract with private agents to use these alternatives. Contract for deferral scheme is discussed in (Poudineh and Jamasb, 2014). For example, TransnetBW, a

German TSO, called upon Fluence, a private firm, to build large battery storages (Fluence, 2022).¹ These "grid-boosters" will reduce congestions from intensive wind generation in northern Germany to intensive industrial load in the south. Driven by their regulator, French DSO Enedis and TSO RTE opened experimental call-for-tenders to all grid customers, consumers and generators, to provide grid flexibility (ENEDIS, 2024; RTE, 2021a). One bid resulted in a ski station shifting its snowmaking machines utilisation (ENEDIS, 2020).

In addition, the French TSO publishes a map of current grid constraints to guide RES owners to less congested areas (RTE, 2024).

The academic literature reflects this evolution with increased consideration of "non-grid" solutions in grid expansion planning exercises in recent years (Gonzalez-Romero et al., 2020; Krishnan et al., 2016). (Jorgenson et al., 2018) show the symbiosis between storage and transmission for wind integration: transmission enables more opportunities for shifting energy, and storage enables greater line utilisation.

Historically, Transmission Expansion Planning (TEP) methods relied on reactive approaches, where transmission is sized in reaction to a generation expansion planned beforehand (Gonzalez-Romero et al., 2020). These methods ignore the potential benefits of trading for a more expensive generation but at a lower connection cost. Although these trade-offs have long been acknowledged (Villasana et al., 1985), they remain uncon sidered in practice.

One reason why TSOs exclude generation assets from their planning is because they cannot involve in generation since the unbundling of the industry. Another reason is that potential benefits were deemed negligible: the generation expansion cost was much higher than the transmission one. TEP has been modelled as a subsequent problem to generation expansion planning. However, given cheaper and decentralised generation, the tides might turn. As displayed in Fig. 2-2, the share of transmission over total system cost is lower for scenarios with centralised nuclear generation (N1, N2, N03) versus scenarios with decentralised renewable generation (M0 M1 M23). Cheaper and decentralised generation and lowering battery storage cost bring back interest to more integrated planning methods.

Unlike TSOs, academics like (Krishnan et al., 2016) or (Liu et al., 2013) use co-optimisation to capture the benefits of simultaneously planning various assets. Co-optimisation papers usually include generation and transmission investment. While co-optimisation of generation

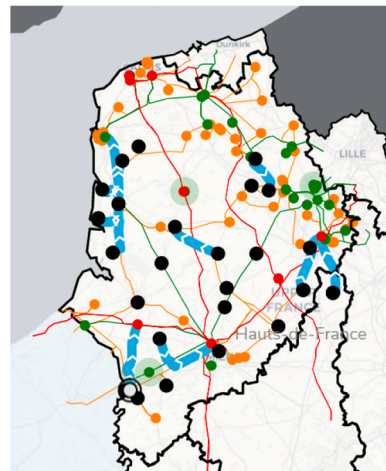


Fig. 2-1. "Blocaux Pas-de-Calais Mont-des-Flandres" area (blue lines indicate constrained lines, red: 400 kV, green: 225 kV, orange: 90 kV). Source: (RTE, 2023).

¹ As of May 2024, the project is still under construction.

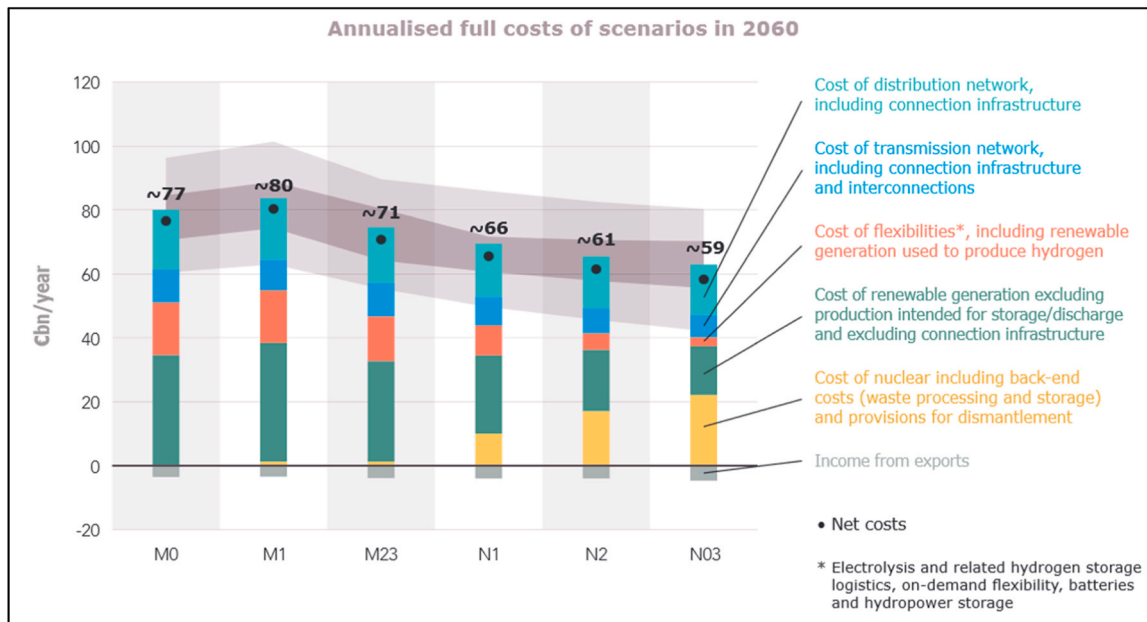


Fig. 2-2. Full costs (production + transmission + flexibility) in France per scenario (based on the baseline consumption trajectory) in 2060 for central scenario and variants. M0: 100 % renewables in 2050, M1: distributed renewables, M23: large renewable farms, N1: renewables + nuclear (8 Evolutionary Power Reactor (EPR)), N2: renewables + nuclear (14 EPRs), N3: renewables + nuclear (14 EPRs + a few Small Modular Reactors (SMR) (RTE, 2021b, p. 31).

and transmission provides unrealistic results in deregulated markets, they still provide interesting insights (Lumbreras and Ramos, 2016). When using a co-optimisation for TEP, the underlying assumption is that demand is inelastic, so that the maximisation of the social welfare comes down to a minimisation of the total system cost. Using a social-welfare maximising approach for TEP assumes that the grid operator is benevolent.

Expansion models increasingly add alternatives to grid investments: demand side response, battery storage, and electric vehicles. (Löschbrand, 2021) includes flexible demand in a transmission expansion model. (Vallés et al., 2016) considers the integration of Active Demand in distribution network planning. (Vatani et al., 2018) show that demand response can replace needed transmission upgrades in the Pennsylvania-New-Jersey-Maryland network.

Storage is particularly interesting among “non-grid” solutions because it can provide various services to the power system. More specifically, lithium-ion battery storage outperforms or will outperform other storage technologies for multiple services: energy arbitrage, frequency reserves, peaker replacement, black start, bill management, power quality, power reliability (Schmidt et al., 2019)... Storage owners can achieve economic viability by stacking different values (Tsagkou et al., 2017), although stacked values potentially cannibalise partially as two services may require simultaneously opposite actions from the storage. It is worth noting that storage value is sometime seen as a complement or a substitute to the grid. (Bustos et al., 2018). (Xu and Hobbs, 2020) study the impact of TEP that anticipates storage investments. Results show that cheaper storage can lead to more or less grid investments depending on local conditions. Whether storage and transmission complement or substitute depends partly on storage cost. The effect of storage cost on this interaction is non-monotonic.

Some modelling aspects influence the relative economic performance of storage compared to the grid.

In a reactive approach modelling, storage would be sized and operated for the generation side independently of transmission constraints. In contrast, proactive approaches account for the influence the grid operator has on generation investors (Rious et al., 2011; Sauma and Oren, 2006). This idea can be extended to storage operators as storage participates in the generation-demand equilibrium. (Nelson et al., 2012)

co-optimises storage with generation and transmission. Two distinct values are captured for storage: one for balancing generation with demand and one for sizing the grid. (Mallapragada et al., 2020) adds primary and secondary reserve procurements in the co-optimisation. The optimisation thus captures a third value for storage. The Flexplan project built a transmission expansion model with ancillary services and reliability considerations in addition (Migliavacca et al., 2021). A reliability requirement in the model, either N-1 or probabilistic line contingencies in that case, strengthens line rather than storage assets for providing grid capacity. Storage cannot fully substitute for a line and when a line is out, as simulated with N-1, only other parallel lines can transmit power.

Another constraint in the grid reinforcement approach can create value for storage. Considering the line lumpiness constraint could advantage battery storage because storage investments can be made in small capacity increments while line investments are lumpy. A line must be invested in its whole nominal capacity, which is determined by its technical parameters: its voltage level and the maximum allowed current that can transit through. TEP models often simplify the representation of line capacity with continuous variables, ignoring the lumpiness of the asset to keep the problem linear. As pointed out by (Krishnan et al., 2016), transmission and generation expansion are often represented with continuous variables. It is the cases of (Nelson et al., 2012) and (Mallapragada et al., 2020) that represent actual grid data with a zonal aggregation. (Xu and Hobbs, 2020) acknowledge the binary nature of line capacity variables but relax the constraint when solving. (Neumann et al., 2022) performs an ex-post discretisation to ensure line investment decisions are valid. The assumption of continuous line capacity is justifiable if the study uses an aggregated equivalent of the existing network. However, it is unrealistic if the study uses an actual network representation. Realistic generation, load, and grid data per bus must be used when planning sub-transmission expansion. So, using a discrete line representation could provide more realistic results. Moreover, a lumpy rather than continuous line representation could create small congestions, which could be more economically managed by a small tailored-to-the-need storage investment rather than a line reinforcement.

The network representation realism may be limited according to the power flow representation. TEP approaches often simplify the network

flow equations. The most accessible power flow representation is the transshipment model, equivalent to Kirchoff’s current law. The equations have the advantage of being linear. However, they implicitly assume power flows can be redirected by ignoring Kirchoff’s voltage law (which is only doable on an actual grid with phase-shifting transformers).

The most accurate representation of power flow is called AC power flow. They include both Kirchoff’s laws, but equations are nonlinear. A linearisation of AC power flow equations is called “DC approximation of AC power flow” or “linear power flow”. With this approximation, the problem stays linear while accounting for the voltage law. Power flows resulting from iterative lossless optimisation with DC approximation are close to simulated AC power flows.

Line losses are often ignored in grid expansion modelling. Line thermal losses are expressed with a quadratic function of the power flows, leading to a non-convex problem. (Neumann et al., 2022) proposes a convex envelop approximation of line losses. The lossy iterative optimisation provides more accurate results than the lossless one, although it is computationally more expensive.

Lastly, optimisation on a multi-horizon could also provide insight into the relative performance of storage to line reinforcement regarding lifetime, construction time, and payback time.

The details of the review (the modelling approaches and the cost parameters used) are available as supplementary material. Overall, we observed various characteristics of grid expansion that may advantage investments in line over storage, or the other way round. We summarize these in the Fig. 2–3. We remark that a fair comparison of storage and grid investment would require extensive and complex modelling. Including ancillary services requirement in the model or representing line thermal losses make storage relatively more economical than line investment. On the other hand, considering reliability requirements or storage thermal losses favour line over storage investments.

In this paper, we focus on the cost factors and the lumpy grid representation in expansion planning. This we allow us to test our intuition that lumpy line might favour the emergence of storage in grid expansion planning.

3. Model

Our paper focuses on the interactions between storage and line investments through co-optimisation. We do not study the profitability of storage from the point of view of a private investor but rather adopt the perspective of a regulated grid operator who maximises social welfare. The grid operator can use storage or line reinforcement to connect new RES generation to the grid. This approach allows us to determine if, given a set of favourable conditions, battery storage could be useful for grid expansion to the benefit of society. To achieve this goal, we built two experiments. The first aims to understand whether storage and grid investments complement or substitute each other. We use the second experiment to evaluate how line lumpiness impacts storage investments.

3.1. Setup and data

We use the open-source package Pypsa (Brown et al., 2018) version 0.25.1. It provides built-in power flow simulations, detailed components for the power system and the network, and storage. It also builds the optimisation problem to be passed on to the solver. We use the glpk solver since it is open source and allow transparency.

All cost data are taken from RTE’s report Futurs Energetiques 2050 (RTE, 2021c, p. 935). Capital costs are annualised with a discount rate of 4.5 % and the respective asset’s lifetime. Annualised capital costs are weighted on the simulation length to be comparable with operational costs. Storage characteristics are also taken from the same report. Line parameters are based on the knowledge of RTE experts. Line cost is usually expressed in terms of €/km, and we use the line length and nominal apparent power to describe it in €/MVA as PyPSA prescribes. The nominal apparent line power $base_{snom}$ is determined with the formula: $base_{snom} = \sqrt{3} \times i \times V$, with i as the current capacity of the line and V as its voltage. PV load factors are taken from the NUTS2 database for the Occitanie region.

This study can be reproduced since all data are coming from public sources and the optimization model used is open source.

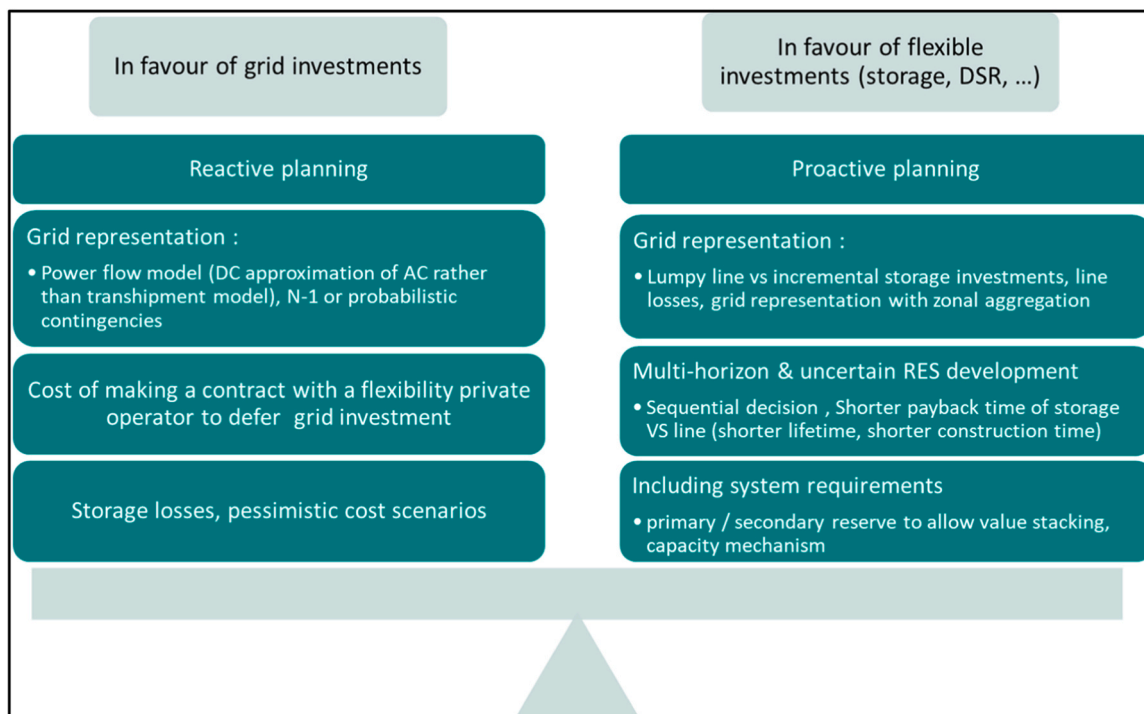


Fig. 2–3. Characteristics of expansion planning models that may favour grid or storage investment.

3.2. Power system, components, and time horizon

We represent distinct power systems for each of our experiments. Each power system has two types of generators: a PV power plant and an upstream power plant. The PV installed capacity is considered exogenous. The upstream generation is used as a last resort solution to ensure the solvability of the optimisation. It can be seen as power withdrawn from the upstream grid or as load shedding.

We model a radial 63 kV grid for both experiments. The power flows are simulated with the DC approximation of AC power flows. Having a radial rather than meshed grid improves the tractability and readability of our results.

We adopt a greenfield approach in the first experiment with no existing line or storage. In the second, each line has an existing capacity equal to its nominal apparent power and no storage is initially installed. Existing lines connect a small PV power plant to the load. We assume that the extension of the PV power plant creates a need for additional grid capacity. The model can expand line and storage capacities. Storage has a non-perfect round-trip efficiency.

In both experiments, we used constant loads to improve the readability of our results. In the first experiment, the load is above peak PV generation. It ensures that storage investments are made to complement grid expansion and not to balance generation with demand. In the second experiment, the load is below PV generation: storage can either shift PV or complement a line investment.

Each of our two power systems encompasses consecutive hourly timesteps. The experiments cover 3 hours and one week of data, respectively. We limit the scope of the results by using a single deterministic week. The weather data represents July 2015 in the South of France for the PV. It is during this period that the PV power output is maximal for this location. This period is when storage is most profitable and when its impact can be most important.

We limit our experiment’s complexity to gain insights into the model’s resulting investment patterns. We can easily extend our system time horizon or components, add stochastic PV generation, or include line losses and grid reliability criteria; it would change the magnitude of the results but not their nature.

3.3. Experiments

We represent two power systems with their reference values (Fig. 3-1 and Fig. 3-2).

3.4. Optimisation functions, decision variables, and discretisation

We assume an inelastic demand so that the maximisation of social welfare is reduced to minimising the total system cost. The decision variables are the investments in storage and line and the dispatch decisions: storage and upstream generation hourly commitment and PV curtailment. The total system cost accounts for the line and storage investment costs and the operational cost of upstream generators.

Line losses are not included in the objective function. It would make the problem quadratic because they are proportional to the square of the current. Disregarding transmission losses can result in overestimated grid expansion (Neumann et al., 2022). Storage investments are even more disadvantaged as we include storage thermal losses.

We use the built-in optimisation function “optimize” of PyPSA, which uses the linear approximation of power flows. If we had used a meshed grid, we would have had to use iterative optimisation. This function iteratively updates the line impedance as the lines are extended. For example, if a line capacity is doubled, its effective impedance is the initial impedance divided by two (see Appendix 1). While this line impedance update will have no impact on radial experiments, it does have an impact on meshed grid expansion.

To visualise the impact of line lumpiness on storage investments, we developed a heuristic approach to optimise on a discrete grid to avoid this complexity (Fig. 3-3). We first optimise line and storage investments, all with continuous variables. We then round the previously optimised line capacities upward or downward to the closest multiple of their nominal apparent value $base_{Snom}$. We fix these values as parameters and then proceed to a second optimisation of the remaining decision variables, i.e., storage investments and unit commitment.

4. Experiments & results

In the first experiment, we explore different solutions for our power system and the role played by storage in the absence of curtailment. We perform a sensitivity analysis on our three cost parameters: line capital cost, storage capital cost, and upstream generation marginal cost. We explore wide ranges of values to observe threshold effects. The observed metric are the objective function value: the total system cost, storage installed capacity, line capacity and the upstream generation.

4.1. Experiment 1: dynamics of line and storage investments

We identify three possible solutions in Table 4-1. In solution A, the load is served solely with upstream generation. In solution B, a line connects PV to the load. Solution C combines storage and line

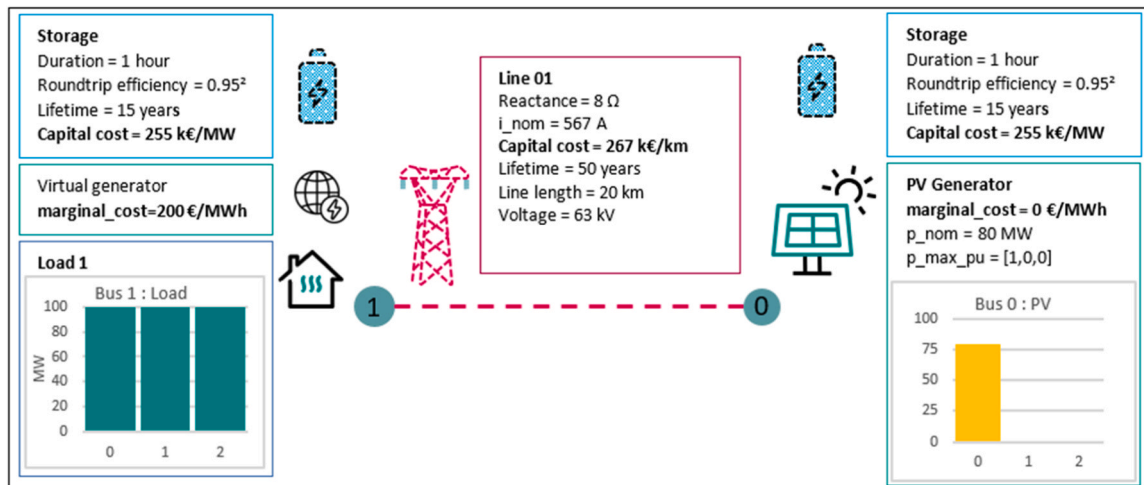


Fig. 3-1. First experiment with reference parameters.

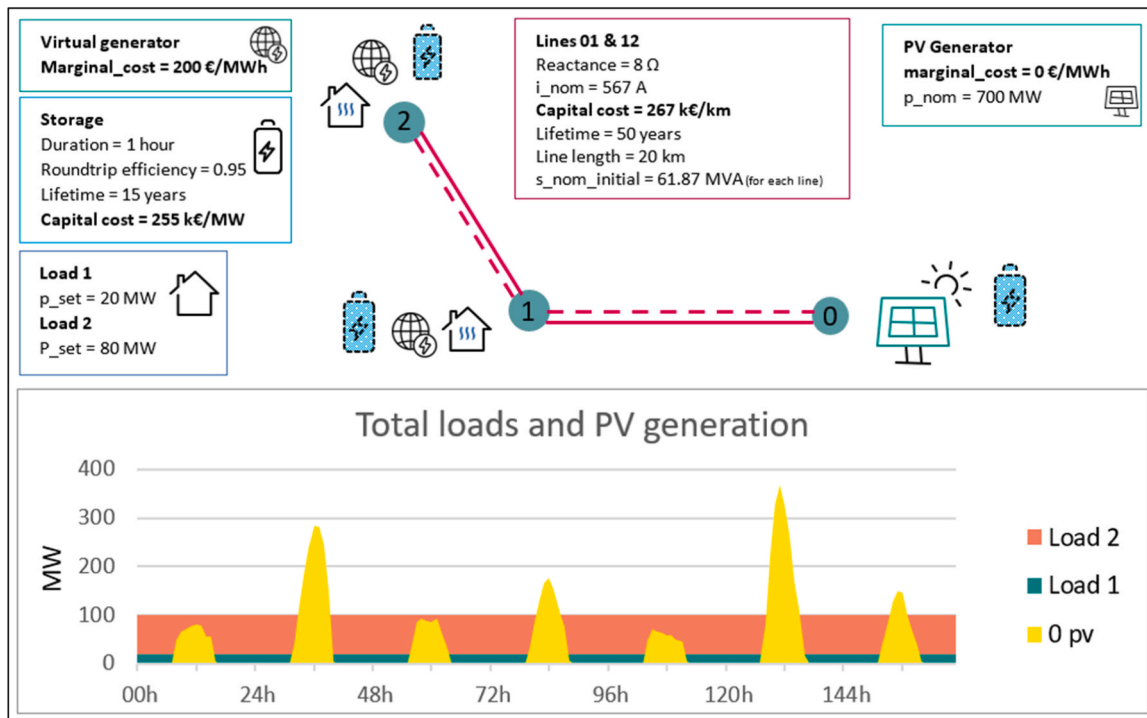


Fig. 3-2. Second experiment with reference values.

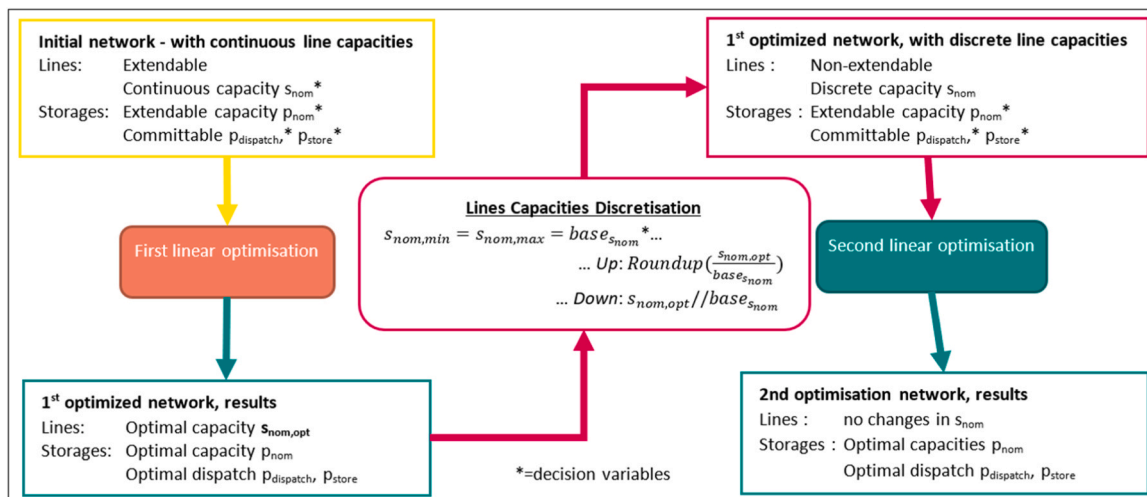


Fig. 3-3. Heuristic approach with iterative optimisation to study the impact of having a discrete grid.

Table 4-1
Three solutions for the co-optimisation combining line and storage investments with upstream generation dispatch.

	Solution A: Upstream generation	Solution B: PV & Line	Solution C: PV with storage and line
Line (MW)	0	80	25
Storage 1 h (MW)	0	0	55 (52 MWh)
Marginal generation (MWh)	300	220	225
Load (MWh)	3*100	3*100	3*100

investments. The remaining load in solutions B and C is met with up-stream generation.

In this first experiment, there is no excessive PV generation

compared to the load meaning no curtailment. Storage, if invested in, acts solely as a substitute to the line. In the solution C {PV+Line+Storage}, storage maximizes the line utilisation with a power flow of 25 MW at each time step. A third of the PV generation transits through the line at the first timestep, the two other thirds are stored and re-injected in subsequent timesteps. The sizes of the line and storage are determined by the PV output (Fig. 4-1).

We then optimise our system with various cost combinations and observe the solutions illustrated above. The reference values used for our first experiment are pictured in Fig. 3-1. We run a cost-combined sensitivity analyses across an extensive range of values. Fig. 4-2 illustrates the total system cost with a colour scale, with each of our three cost parameters drawn on an axis. Detailed results can be found in the supplementary materials.

Cost ranges are vast. Although studied values are unrealistic, they

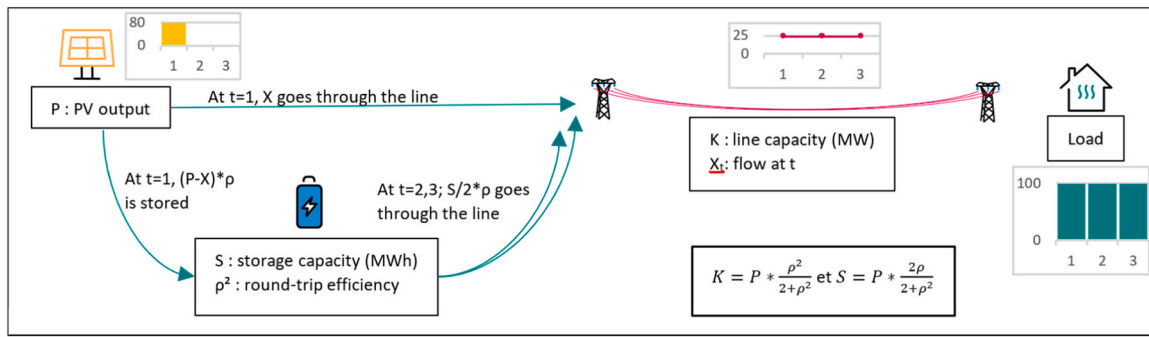


Fig. 4–1. Analytic solution C where storage participates in the grid sizing along line investments for PV integration.

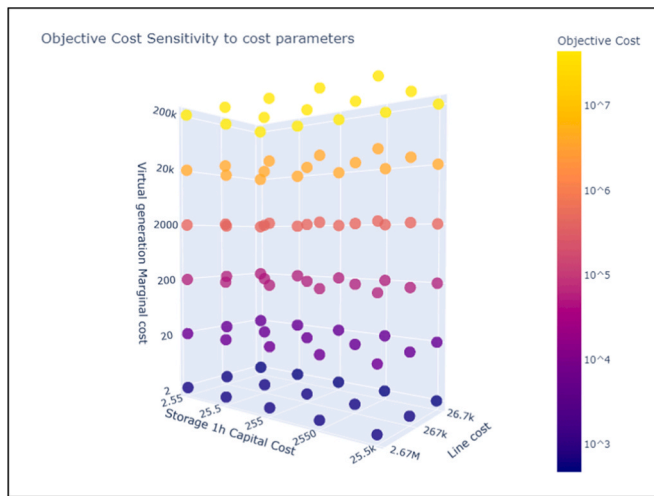


Fig. 4–2. Total system cost values for various cost combinations {storage capex, line capex, fall back generation marginal cost}.

allow us to explore threshold effects. We observe the most influential cost parameter on the z-axis, the upstream generation marginal cost. This is explained by the large amount of leftover load after PV generation and by storage loses. The two other cost parameters, line and storage capital costs, appear to have little or no influence.

We then fix the marginal cost with a value of 200€/MWh to observe the influence of the two other cost parameters.

Table 4–2 shows the capacities installed in MW for line and storage as well as the generation dispatched in MWh and the total system cost. For most cases, there are no storage installed at all. The optimal solution is like solution B {PV+line} with line and no storage. The solution C {PV+line+Storage} is observed only for the highest line cost considered, where it is 10⁴ its reference value.

The line cost is the second most important cost parameter in our power system: a 10⁴ increase of the reference line cost leads to increase of +5–8 % of the total system cost. The storage cost has no influence on the optimal solution once the cost threshold is crossed and the solution shift from B to C: the storage capacity remains of 55 MWh.

We also observe results for a lower marginal cost in Table 4–3: 20€/MWh. Decreased marginal cost means that storage becomes more competitive against the line: since storage loses energy, the system must buy back from the upstream grid the thermal losses. The solution C appears for a lower line cost, 10³ its reference value.

Given a situation without excessive PV generation, where storage sole purpose is to contribute to the grid sizing by substituting partially to a line investment (solution C), we identify that the marginal energy cost is the most influential parameter, followed by the line cost, and finally by the storage cost. Also, we identify three characteristics for solution C

Table 4–2

Results for experiment 1: Storage and Line installed capacities, Dispatched generation, and Total System Cost (for a marginal cost of 200€/MWh).

Storage investments (MW)			
Storage Cost	Ref*10 ⁻¹	Ref	Ref*10
Line Cost			
Ref	0	0	0
Ref*10 ³	0	0	0
Ref*10 ⁴	55.12	55.12	0
Line investments (MVA)			
Storage Cost	Ref*10 ⁻¹	Ref	Ref*10
Line Cost			
Ref	80	80	80
Ref*10 ³	80	80	80
Ref*10 ⁴	24.88	24.88	80
Upstream generation (MWh)			
Storage Cost	Ref*10 ⁻¹	Ref	Ref*10
Line Cost			
Ref	220	220	220
Ref*10 ³	220	220	220
Ref*10 ⁴	225.37	225.37	220
Total System Cost (€)			
Storage Cost	Ref*10 ⁻¹	Ref	Ref*10
Line Cost			
Ref	44 000	44 000	44 000
Ref*10 ¹	44 003 (+0.01 %)	44 003 (+0.01 %)	44 003 (+0.01 %)
Ref*10 ²	44 034 (+0.08 %)	44 034 (+0.08 %)	44 034 (+0.08 %)
Ref*10 ³	44 339 (+0.77 %)	44 339 (+0.77 %)	44 339 (+0.77 %)
Ref*10 ⁴	46 174 (+4.94 %)	46 577 (+5.86 %)	47 389 (+7.70 %)

to be optimal: high line cost, low energy price, and high efficiency.

4.2. Experiment 2: grid discretisation impacts storage economic space

The reference values used for our second experiment are pictured in Fig. 3-2. In this experience, we assume there is a pre-existing small PV power plant installed at bus 0. Two lines already exist; one connects the PV power plant to the closest load bus, and the other connects the two load buses. We extend the PV capacity: the PV generation becomes higher than the loads and higher than the existing line capacities. Line reinforcement or storage investments are needed. Curtailment appears. Results are displayed in Table 4–4.

Compared to the first experiment, storage can serve as a substitute to grid reinforcement but also to shift curtailed energy. Two additional solution types can be identified: solution D where storage simultaneously substitute to the grid and shift curtailment, and solution E where storage only shifts curtailed energy without participating in the grid sizing.

This additional role of storage increases its value for the system. For example, in the storage and line reference costs scenario, it is a solution E. The lines capacity is respectively 100 and 80 MVA, meaning that the loads can be served with PV generation instantaneously. One MW of storage is installed to shift remaining curtailment. And if storage cost

Table 4–3

Results for experiment 1: Storage and Line installed capacities, Dispatched generation, and Total System Cost (for a marginal cost of 20€/MWh).

		Storage investments (MW)		
Storage Cost	Ref*10 ⁻¹	Ref	Ref*10	
Line Cost				
Ref	0	0	0	
Ref*10 ³	55	0	0	
Ref*10 ⁴	55	0	0	
		Line investments (MVA)		
Storage Cost	Ref*10 ⁻¹	Ref	Ref*10	
Line Cost				
Ref	80	80	80	
Ref*10 ³	25	80	80	
Ref*10 ⁴	25	0	0	
		Upstream generation (MWh)		
Storage Cost	Ref*10 ⁻¹	Ref	Ref*10	
Line Cost				
Ref	220	220	220	
Ref*10 ³	225	220	220	
Ref*10 ⁴	225	300	300	
		Total System Cost (€)		
Storage Cost	Ref*10 ⁻¹	Ref	Ref*10	
Line Cost				
Ref	4 400	4 400	4 400	
Ref*10 ¹	4 403 (+0.01 %)	4 403 (+0.1 %)	4 403 (+0.1 %)	
Ref*10 ²	4 434 (+0.8 %)	4 434 (+0.8 %)	4 434 (+0.8 %)	
Ref*10 ³	4 658 (+5.8 %)	4 739 (+7.7 %)	4 739 (+7.7 %)	
Ref*10 ⁴	5 606 (+27.4 %)	6 000 (+36.4 %)	6 000 (+36.4 %)	

Table 4–4

Results for experiment 2: Storage and Lines installed capacities, Dispatched generation, Remaining curtailment (for a marginal cost of 200€/MWh and 400 MW of installed PV).

		Storage investments (MW)		
Storage Cost	Ref*10 ⁻²	Ref*10 ⁻¹	Ref	
Line Cost				
Ref	448	366	1	
Ref*10	596	596	1	
Ref*10 ²	596	596	110	
Ref*10 ³	596	596	110	
		Line investments (line 01; line 12) (MVA)		
Storage Cost	Ref*10 ⁻²	Ref*10 ⁻¹	Ref	
Line Cost				
Ref	86; 66	100; 80	100; 80	
Ref*10	62; 62	62; 62	100; 80	
Ref*10 ²	62; 62	62; 62	62; 62	
Ref*10 ³	62; 62	62; 62	62; 62	
		Upstream generation (MWh)		
Storage Cost	Ref*10 ⁻²	Ref*10 ⁻¹	Ref	
Line Cost				
Ref	12993	12984	13523	
Ref*10	13015	13015	13523	
Ref*10 ²	13015	13015	13773	
Ref*10 ³	13015	13015	13773	
		Curtailment after optimisation (MWh)		
Storage Cost	Ref*10 ⁻²	Ref*10 ⁻¹	Ref	
Line Cost				
Ref	0	0	567	
Ref*10	0	0	567	
Ref*10 ²	0	0	798	
Ref*10 ³	0	0	798	

decreases by a factor 10, it is still a solution E (storage useful for shifting curtailment). There is 366 MW of storage while the lines capacity remains similar. If storage cost decreases by another factor 10, it becomes a solution D (storage useful for grid sizing and curtailment shifting). The installed lines capacities are reduced to 86 and 66 MVA and storage capacities further increase to 448 MW.

We observe that the optimisation is more sensitive to storage cost than previously. We also notice some leftover curtailment after

optimisation. It is because the PV peaks are not frequent or important enough: additional storage would not be used sufficiently and wouldn't be profitable for the system.

We finally assess the impact of having nominal grid capacities. We compare the results of different optimisations: one with continuous variables for line capacities, and two others with fixed parameters after having rounded upward or downward the grid capacities (the method is described in Fig. 3-3).

The impacts of setting the grid capacities to discrete values depend on the type of solution obtained for the continuous optimisation.

We present a first set of results in Table 4–5, where the continuous optimisation returns a solution D (storage simultaneously substituting and shifting). In the second set of results presented in Table 4–6, the continuous optimisation returns a solution E (storage doesn't contribute to grid sizing and only shift curtailment). We can see that storage doesn't contribute to the grid sizing as the installed line capacities are capped by the load values. The line from the PV power plant is 100 MW and the line connecting load buses is 80 MW to feed the loads of 20 MW at bus 1 and 80 MW at bus 2.

Rounding upward line capacity in the case where storage contributed to the grid (solution E, Table 4–5) decreases storage investments. In this case, considering the line lumpiness is detrimental to storage as it limits its potential value. Rounding upward in the case where storage did not contribute to the grid (solution D, Table 4–5) has no effect on storage investments as it did not participate in the grid sizing.

Rounding downward strongly increases storage investments in both cases and it limits power flows. It creates a large amount of curtailed energy, partially managed by storage investments. Storage investments increase to manage PV and maximise line utilisation. If storage did not participate in grid sizing, it now does (Table 4–6).

We now observe the discretisation impact on the total system expansion cost (Table 4–7). The total system cost is hereby defined here by the line reinforcements cost (excluding pre-existing line costs), the storage investments and the upstream generation dispatched.

First looking at reference costs scenarios, we observe that rounding down has a more significant impact on the total system cost than rounding up. The gap increases with PV installation: additional PV generation creates larger congestions, which can be tackled more effectively with more line capacity (round-up) rather than more storage (round-down).

We study other cost scenarios where we boost storage relatively to line reinforcement, by increasing the line cost or lowering the storage cost. In these scenarios, we nuance the previous conclusion: rounding up can be more costly than rounding down.

5. Discussions

In our first experiment, the co-optimisation of power systems with storage, reinforcement, and dispatch can deliver three different outcomes.

The first solution observed is when upstream generation meets all the demand. It happens if storage and line costs are both prohibitive (solution A).

Otherwise, storage can be valued for actively participating in grid sizing and balancing load and demand (solution C). Given a strong PV generation, it maximises the lines utilisation throughout the week. The system needs three conditions for such optimal solutions. First, it needs a low marginal cost (here below 200€/MWh). Since storage loses energy when cycling, thermal losses must be repurchased by the system at the marginal cost price. Second, storage must have a high round-trip efficiency to limit losses. Lastly, the system needs expensive lines (or cheap storage) to have storage become competitive against reinforcement. Our model is simple; we cannot judge the costs realism. Although these cost conditions could be considered unrealistic (storage ten times below reference cost or line ten times above reference cost), prohibitive line costs could exist in highly constrained areas (mountain or urban areas

Table 4-5

Rounding lines capacity after solution D: Storage and Lines installed capacities, Dispatched generation, Remaining curtailment (Marginal Cost = 200€/MWh, PV installed = 400 MW, **Storage cost = Reference * 10⁻²**, Line cost = Reference).

	Storage investments (MW)	Line investments (line 01; 12) (MVA)	Upstream generation (MWh)	Curtailment final (MWh)	Total System Cost (€)
Continuous optimisation	448.11	86.01; 66.01	12 992.98	0	2 602 935
Optimisation after rounding down	596.12	61.87; 61.87	13 014.80	0	2 605 675 (+0.11 %)
Optimisation after rounding up	365.76	123.74; 123.74	12 984.14	0	2 609 343 (+0.25 %)

Table 4-6

Rounding lines capacity after **solution E**: Storage and Lines installed capacities, Dispatched generation, Remaining curtailment (Marginal Cost = 200€/MWh, PV installed = 400 MW, **Storage cost = Reference**, Line cost = Reference).

	Storage investments (MW)	Line investments (line 01; 12) (MVA)	Upstream generation (MWh)	Curtailment final (MWh)	Total System Cost (€)
Continuous optimisation	0.98	100; 80	13 523.22	567.45	2 709 843
Optimisation after rounding down	109.72	61.87; 61.87	13 772.79	797.88	2 804 519 (+3.49 %)
Optimisation after rounding up	0.98	123.74; 123.74	13 523.22	567.45	2 715 939 (+0.22 %)

Table 4-7

Changes in % of the Total System Cost (existing lines excluded) between Continuous optimisation and Round-up / Round-down.

PV	400 MW				600 MW							
	Ref*10 ⁻²		Ref*10 ⁻¹		Ref		Ref					
Storage cost												
Line cost	Ref	Ref*10	Ref	Ref*10	Ref	Ref*10	Ref	Ref*10	Ref	Ref*10	Ref	Ref*10
Round-down compared to Continuous	0.11 %	0%	0.45 %	0%	3.49 %	1.89 %	0.28 %	0%	0.77 %	0%	4.87 %	3.11 %
Round-up compared to Continuous	0.25 %	0%	0.23 %	0%	0.22 %	2.21 %	0.27 %	0%	0.27 %	0%	0.24 %	2.39 %

with strong environmental limitations). A prohibitive cost can also translate to the grid operator's inability to invest, given financial and industrial investment capacity limitations.

If one of those conditions falls, the optimal solution is like solution B. Storage no longer participates in the grid sizing. PV generation is either curtailed or stored. If storage is installed, it only balances generation and demand. The frequency and the size of peak PV generation will limit storage investment for curtailment instead.

The main takeaway from this first experiment is the following. Given a power system without curtailment, the most decisive cost parameter when choosing between storage or grid reinforcement is the marginal cost of generation, followed by the cost of the grid reinforcement and, finally, ahead of the storage cost. Another takeaway is that, when storage acts as a substitute of the grid only (without being used for shifting curtailment), the storage installed capacity is fixed: storage is sized to maximize the line utilisation. In our example, a third of the PV generation transited in the first hour, and the two other thirds were reinjected during the second and third hour.

In our second experiment, we then extended our simulation to a one-week horizon with more realistic PV profiles. We choose a period with high PV output so that storage investment could have as a great an impact as possible. We considered existing lines and studied how storage can complement or substitute line reinforcements. To capture the incremental nature of storage, as opposed to the line's lumpiness, we rounded up or down the number of parallel lines. We observed how optimal investments and total system cost are impacted.

First, we observe that increasing storage cost will limit storage values. As the storage cost increases, storage turns from being valued for both grid sizing and generation-demand sizing, to solely shifting PV generation to meet demand, and eventually is removed by curtailment.

Then, we observe the impact of rounding the number of parallel lines. In some cases, lines were not expanded beyond existing capacities

in the continuous optimisation. We focused our observations on cases where rounding up or down had an impact on both lines' capacity.

Rounding up to the next higher integer, the number of parallel lines reduces storage investments only if the latter participates in the grid sizing. Otherwise, storage investments are unaffected. Curtailment is reduced after rounding up only if the loads did not already cap the line capacities. If we had represented a demand above the PV generation, we wouldn't have had curtailment, and storage wouldn't have been invested in for its value of balancing generation and demand but only for its value for grid sizing. When rounding down the line capacities, the optimisation balances with a mix of higher curtailment and storage investments.

Finally, with the impacts on the total system cost, we observe that rounding up is more economical than rounding down, given reference costs. This statement becomes less edgy as storage becomes more competitive than line reinforcement.

We wanted to assess the impact of having a discrete line representation in grid expansion planning and see if it enabled the development of more storage capacities. In this experiment with a surplus of renewable generation, we first explore optimal solution with continuous grid capacities. Storage can be used to substitute to the grid but also to shift excessive power through time. The optimisation thus captures two aspects of storage value: grid deferral and energy arbitrage. While exploring different cost scenarios, we observe that storage mostly appear to shift curtailed energy, and sometime for shifting and substituting to some grid capacity.

We also explored results over a full-year time horizon thanks to the commercial solver Fico Xpress. Results are detailed in supplementary materials. We observe that larger storage capacities are installed relatively to the line capacities when compared to the one-week optimisation: as we extended our time horizon, we considered more curtailment periods, releasing additional opportunities for storage. However,

similarly to the one-week experiment, storage seldomly participates in grid sizing. Rounding down becomes much more expensive than rounding up.

If a grid operator wanted a realistic grid representation using our heuristic approach, he could round up to observe the least expensive option or round down to observe the maximum storage expansion. Rounding up is in the interest of regulated grid operators, whose remuneration is based on their capital expenditure spendings. Rounding downward means less grid and more storage investments. For a grid operator, it comes down to trading capital expenditures for operational expenditures. This option is more expensive is more expensive for the system.

However, these conclusions are limited for several reasons. We used a single horizon with a single investment decision in a deterministic setting. As put forward by (Schachter and Mancarella, 2016), storage allow the system to make sequential investment decision and, given some uncertainties, adapt the investment decisions as the future unveils. Since some of the grid expansion is driven by renewable expansion, considering uncertainty regarding the size, the location and the pace of installation could advocate for storage investments.

6. Conclusion and perspectives

This paper is part of the academic literature covering storage and grid co-expansion to foster renewable generation integration. Most of the literature focuses on the transmission grid. We focus on a lower voltage grid, which brings different constraints. As we represent an actual sub-transmission grid, we need to represent our lines' capacity with discrete values rather than continuous variables. By using a co-optimisation, we value storage on two aspects: its ability to manage congestion and reduce grid reinforcement, and its shifting of PV peak generation to meet demand.

First, we identified key determinants of storage value by characterising storage and line investments for PV integration. Storage can be a viable alternative for grid sizing given three factors: high line cost, high storage efficiency and low energy prices. Although we used a simple power system (two nodes, three hours, constant load, deterministic, etc.), these factors remain determinants for larger, more complex grids.

Secondly, we increased PV generation so that it exceeded demand. Storage investments partially offset the excess PV generation, and in some cases, storage simultaneously contributed to the grid sizing. We also considered optimisation after rounding the number of parallel lines of the grid. After rounding up, storage was not affected or reduced. Rounding down increased drastically congestions, and large additional storage capacities are installed. However, the impact on the total system cost is higher than when rounding up (given reference costs). Based on our observations, optimisation with discrete variables would be detrimental to storage, with more lines and less storage investments than with a continuous optimisation.

Eventually, storage could be an economical alternative in regions subject to severe local constraints if energy cost is low, and if storage's economic and technical efficiencies are high. Considering storage for grid sizing appears to be non-economical in non-constrained regions, where the line cost would be the reference and given storage reference cost. Although storage may not offer a large-scale solution as a substitute for grid reinforcement, it could serve as a viable local alternative. Since grid operators are not necessarily benevolent, the regulators should incentivize the consideration of alternatives such as battery storage in parts of the grid where traditional grid expansion is strongly constrained.

This work could help meshed grid operators identify the role of storage as a complement to grid reinforcement. Unlike when using an iterative or a generation-first expansion planning approach, a co-optimisation has the advantage of operating batteries in a way that avoid creating additional congestion and respect expanded grid constraints.

Table 5-1

Impacts of optimising after rounding the grid lines capacity (reference costs scenario).

	Optimisation after rounding up	After rounding down
Total system cost	Increased a little	Increased more
Storage capacity	Unaffected or reduced in some specific cases	Increased
Curtailed PV	Unaffected (if the loads already capped lines capacities) or reduced	Increased (as storage can economically manage only part of the newly created congestions)

One line of new research should investigate other potential values of storage. The more potential value streams we add, the more competitive storage would become. These new value streams can be explored regarding storage potential contributions, being its shorter payback period, its reduced construction time, its potential to reduce sunk costs, or its complementarity with RES deployment constraints.

CRediT authorship contribution statement

Kutluhan Pak: Supervision. **Vincent Rioux:** Supervision. **Adrienne de Bazelaire:** Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Resources, Project administration, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Yannick Perez:** Writing – review & editing, Supervision.

Declaration of Competing Interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests. Adrienne de Bazelaire reports financial support was provided by Réseau de Transport d'Electricité. If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgements

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper. We would like to thank the participants of the many conferences and internal workshops were the paper has been discussed, like IAEE conference in Athens, YEEES conference in 2023 and the LGI working papers days. We also thank the developers of PyPSA and its user's community for providing the package and assistance.

Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at [doi:10.1016/j.tej.2024.107419](https://doi.org/10.1016/j.tej.2024.107419).

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