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POWERING THE FUTURE:

ENERGY STORAGE IN TOMORROW'S ELECTRICITY MARKETS

INTRODUCTION

Energy storage, encompassing the storage not only of electricity but also of energy in various forms such as chemicals, is a linchpin in the movement towards a decarbonized energy sector, due to its myriad roles in fortifying grid reliability, facilitating the integration of renewables, and advocating for energy efficiency and equity. It acts as a conduit for the incorporation of intermittent renewable energy sources by storing surplus energy and supplying it during periods of high demand or low renewable output, consequently reducing the curtailment of renewable energy and reliance on fossil-fuel-powered plants. This is crucial for maintaining grid stability in systems with substantial renewable penetration. The continuous innovation in this domain is driving advancements in scalability and economic viability, thereby reinforcing energy storage's pivotal role in achieving a sustainable and decarbonized energy future.

The cost of storage resources has been declining in the past years; however, they still do have high capital costs, making investments in such resources risky, especially due to the associated uncertainty in revenues and the regulatory framework. Storage investors participate in energy, ancillary services, and capacity (if available) markets to stack their revenues. However, their revenues might be affected by, for example, demand-side flexibility, and market saturation, which exposes them to economic risk. Governments have intervened to design markets and support schemes that mitigate these risks—for example, with cap-and-floor regimes or targeted support schemes. Along with support mechanisms, electricity markets need to be tailored for storage resources and their inter-temporal nature and provide them with the appropriate signals for both efficient short-term operation and long-term investments in various technologies. A mix of storage resources is necessary for the hour-to-hour, day-to-day, and long-term system operations that mitigate the effects of interannual renewable generation variability. Batteries are suitable candidates to provide support in short-term operations; however, long-term storage will be provided by chemical solutions such as hydrogen. To enable the deployment of storage resources, the appropriate infrastructure needs to be built in a timely manner.

Given this background, the articles in this issue of the *Oxford Energy Forum* debate the topics of how storage investments can mitigate risk, if current electricity market designs are appropriate for storage resources and how they can participate in them, and the way to go forward in terms of long-term storage and its implications.

Danthine and *Zerain* argue that storage investments need to be supported by mechanisms and innovative market solutions to ensure long-term revenue certainty. The authors argue that the lower volatility and reduced spread in prices in energy markets of future low-carbon power systems with increased flexibility from demand response pose economic risks to storage investors. Their revenue diversification is also challenging due to the small size of ancillary services markets that tend to saturate quickly. Last, the existing regulatory framework poses risks due to, among other things, ambiguities in market rules and participation requirements. However, these risks can be mitigated with long-term revenue certainty and portfolio diversification. A few examples of such approaches include participation in capacity markets, enforcement of cap-and-floor regimes, profit-sharing arrangements, and hybrid power purchase agreements with co-located renewable resources.

Billimoria argues that collars (a combination of caps and floors over a set period such as a year) have a significant potential as a hedging risk instrument for storage investments. This mechanism was recently proposed by the Commonwealth Government in Australia as part of its Capacity Investment Scheme. According to the author, traditional forms of derivative and risk-hedging contracts, like reliability options, are not suitable for storage resources due to their multidimensional nature and participation in multiple ancillary service markets that are co-optimized with energy markets. Collar contracts have several desirable attributes—for example, incentive compatibility with spot market signals, limiting distortion of existing derivative and contract markets, avoiding moral hazards, efficient procurement, and short-term operational incentives of the storage unit to continue to profit-maximize and participate optimally in the spot market. However, the author states that there are complexities—such as risk profile and liability exposures, redistribution procedures, price formation, and impact to the system resource—in their implementation. The author argues that further research on collar contract design to make it less interventionist is necessary, and that the development of other mechanisms to create short-term signals, such as emissions externalities, is imperative since such risk-hedging mechanisms are not sufficient to do so.

Apostolopoulou and *Poudineh* argue that the regulatory and market framework should not bias towards co-located storage and renewable generation aggregate projects as a support mechanism, since operationally linked projects in the virtual world have several benefits to the system. As such, the regulatory and market framework need to be designed to provide the appropriate signals that favour either physical or virtual linkage depending on the specific system conditions. The motivation behind co-located aggregate projects is to take advantage of complementary characteristics as well as benefits from co-locating two resources, for example in easing the permitting process. Even though there has been an increased interest worldwide in co-located storage and renewable generation projects, their main drawback is that at least one of the technologies used is sited in a suboptimal location. However, in the authors' view, when storage and renewable resources are linked virtually in the context of a virtual power plant, then that is not the case. It has been found that virtual power plants benefit the system by reducing the cost of electricity by decreasing reliance on expensive peaking units and by reducing greenhouse emissions by expanding grid capacity and absorbing higher shares of renewable energy. As such, the authors assert that the market and regulatory frameworks should not bias towards a particular type of interaction, physical or virtual, and that if designed appropriately, they suffice to give the appropriate investment signals.

Dagoumas, in the context of the Greek electricity market, argues that there is a need for a state intervention to support storage investments as an intermediate step towards facilitating their uptake, aiming at their penetration on a market basis in the medium to long term. Greece followed a top-down approach when designing long-term strategies for storage deployment, with the objective to maximize social welfare. This involves facilitation of licensing processes to enhance competition, provision of state aid schemes for investment and operating support, and network expansion and obligation of new renewable energy resources to be accompanied by storage assets. The plan is to transform Greece from a net electricity-importing country, as it has been over the last decades, to a net electricity-exporting country, specifically of green energy, with increasing interconnection capacity with neighbouring systems (Bulgaria, Italy, Turkey, North Macedonia, Albania, and Cyprus), while interconnections with Egypt, Saudi Arabia and Slovenia-Austria-Germany are explored. Besides the storage investors' support schemes, they can participate in the wholesale market and/or form bilateral purchase power agreements. The author asserts that even though there is no optimum solution in the design of energy storage deployment strategies, elements of the Greek policy intervention could be adopted by other states.

On the topic of electricity markets' suitability for storage resources, *Mays* focuses on organized wholesale markets in the United States and argues that changes need to be made in the valuing, contracting, and modelling of storage resources to facilitate their deployment. The value of storage is determined in terms of energy, ancillary services, and resource adequacy. Under idealized assumptions, volatility in prices is sufficient to support efficient operation of and investment in storage. However, market operators and regulators have good reason to avoid it. The author asserts that suppression of price volatility implies a need for interventions to restore efficient incentives for flexibility. A second set of challenges concerns how to facilitate contracting around those value streams. Reserve products, resource adequacy (e.g. through strips of swing options), and preservation of incentives for efficient storage operations in the short term are the key features that affect the efficiency of storage contracting. Last, the author highlights the need for an update to the static merit order dispatch model with a dynamic modelling framework where marginal costs include not only the direct cost incurred in the present period, but also the change in expected cost that will be incurred in future periods based on the state of the system resulting from current actions.

Botterud, *Korpås*, and *Tarel* argue that energy-only markets with scarcity prices set to value of lost load may continue to provide adequate incentives for operations as well as investments and cost recovery after the introduction of renewable generation and storage resources. To reach this conclusion, the authors study four scenarios spanning from a traditional thermal to a fully decarbonized system. The authors find that the amount of time when load exceeds supply remains the same as long as thermal generators are part of the optimal mix. If the system reaches a state where flexible generators with non-zero marginal costs are no longer part of the optimal resource mix, equilibrium prices need to directly reflect the capital costs of renewable generation and storage resources. This raises questions under current electricity market designs that assume offers are based on marginal costs and that if they deviate from these market power might be exercised. According to the authors, a potential solution lies in long-term energy contracts where capital costs can be more directly reflected in market clearing prices. The authors conclude that marginal improvements to existing market designs will be sufficient in a future renewable- and storage-dominant resource mix.

Xu and *Hobbs* argue that storage resources need to submit details on opportunity and degradation costs when participating in energy and ancillary services markets so that their scheduling is economically efficient and attempted exercise of market power is readily detected. Truthful bidding of costs remains a goal of market design, even as generation mixes have shifted to variable renewables and, increasingly, battery storage. However, opportunity costs rather than fuel costs make up an increasing proportion of variable costs, and are challenging for market participants to estimate and for market operators to monitor. In this regard, storage resources are now allowed to submit bids that exceed their physical discharge costs, predicated on anticipated future price surges. However, complication and uncertainty exist regarding determining opportunity costs—for example, duration of market intervals result in underestimation of storage value. The authors also argue that the opportunity costs arising from degradation are substantial and need to be included in bids, which is a difficult task due to technical and economic challenges, since a time horizon from 5 to 20 years needs to be studied. These challenges in determining the opportunity costs are the source of friction between storage resources who wish to maximize profits, system operators who are concerned with reliability and cost minimization, and monitors who are trying to prevent market gaming. The authors argue that the solution is to share more information between the involved parties so that these disagreements can be resolved more easily.

Hübner and *Hug* argue that both block and multi-part bids should be allowed in an electricity auction to enable the efficient participation of storage entities. The basic idea of both bids comes from the combinatorial auction, which allows the simultaneous trade of multiple goods. In European electricity markets the idea of block bids is used to couple power supply or demand at different hours—that is, to allow for storage's inter-temporal constraints. In contrast, in the United States, storage resources specify their willingness to buy or sell electric energy somewhat indirectly through asset-specific multi-part bids. Block bids currently do not allow a bid that contains both buy and sell quantities, but as an alternative allow linking buy and sell blocks to be executed together. However, the number of block bids in an auction is limited, thus leading to the 'missing bid' problem. This problem may be avoided by multi-part bids that allow storage entities to specify all their possible operating states compactly. However, multi-part bids are likely inaccurate or unsuitable for agents with preferences that deviate from the common ones defined by the auctioneer; as such, they introduce barriers to entry for new entrants. The authors argue that by using both bid formats the problems of each could be mitigated, and it is best to reconcile two seemingly distant ideas from opposite sides of the Atlantic.

On the topic of long-term storage, focusing on the Great Britain power system, *Llewellyn Smith* argues that it is important to study long continuous sequences of years when evaluating the need for storage, as studies that look at individual years (however many) seriously underestimate the need for storage and overestimate the need for other flexible supply and wind. This is the result of long-term variations in wind supply related to the North Atlantic and Arctic Oscillations, which require storage of large amounts of energy for decades in Great Britain. This is also true in the north-east United States and Texas. Details on the modelling may be found in the recent Royal Society report on electricity storage. The need for very large large-scale long-term storage points to hydrogen, ammonia, and electro-fuels due to their very low capital cost per unit of energy stored and negligible energy losses. With high levels of wind and solar supported by hydrogen, the 2050 cost of electricity in Great Britain will be higher than in the last decade, but lower than in the last year, and much lower than in 2022. The cost per MWh depends weakly on the temporal profile of demand, but not on its level. The author also states that combining advanced compressed air storage with hydrogen would be likely to lower the cost relative to that found with hydrogen alone (by up to 5 per cent, or possibly more).

In the context of Great Britain's electricity market, *Rhys* in his article, which is complementary to that of Llewellyn Smith, argues that to ensure reliable future low-carbon systems there is a need to achieve a balance between markets and central coordination, and a radical reappraisal of the economics of reliability in power systems. Large power systems inevitably pose issues of coordination, and the issue of whether efficiency and reliability can be achieved more effectively through central coordination or in a more decentralized manner through price signals and market forces alone. Systems that include reliance on renewables and storage introduce additional levels of complexity much less amenable to simple market solutions. Based on the recent Royal Society report on energy storage, the author argues that in future systems, storage will be necessary both in the short term, for example in the form of batteries to deal with day-to-day variability, and in the long term to deal with interannual variability. Long-term storage, for example based on hydrogen, has all the characteristics of a natural monopoly and large-scale infrastructure. As such it can be treated as a regulated asset with the objective to minimize capital cost and maintain a high level of reassurance over future revenue streams and the future market and regulatory environment. Last, the author argues that we need to think of energy rather than power when planning for reliable future systems.

Focusing on the French electricity system, *Plessiez*, *Xavier*, and *Panciatici* argue that increasing energy efficiency, reducing energy demand, maintaining adequate availability of the existing nuclear fleet, and expanding renewable energy are the main four pillars to accelerate the shift from fossil fuels to low-carbon energies and to enhance the country's energy and industrial sovereignty. The authors state that flexibility needs cannot be simply summarized as an energy value; they must consider various characteristics in managing the electrical supply-demand balance. Beyond load modulation, battery storage constitutes the second flexibility expected to play an increasingly significant role in the flexibility of the electrical system. Challenges in the planning process become complex when dealing with larger, interconnected multi-energy networks, particularly given their growing uncertainty and volatility. A major uncertainty also relates to the flexibility associated with the development of hydrogen and future energy markets' structure and outcomes. Sector coupling allows long-term storage; for example, synthetic methane, hydrogen, and ammonia could become increasingly important in the operation of multi-energy systems. The authors state that all these challenges pinpoint the need for increased collaboration between utilities, industrial partners, and academics, to improve the way flexibilities are considered in system planning studies and provide insights to support the transition towards a carbon-neutral energy system.

The last article of the issue, by *Edlmann*, argues that hydrogen holds a strategic position in future low-carbon systems that need long-term storage to tackle seasonal renewable generation variations. The author presents the various geological hydrogen storage technologies—such as pipelines, subsurface silos, lined rock caverns and shafts, salt caverns, and porous rock storage—and their technical challenges in terms of high production costs, losses during power-to-gas-to-power as well as hydrogen transport and storage infrastructure. The author states that the Hydrogen Transport Business Model and Hydrogen Storage Business Model are key components for hydrogen storage. In terms of planning and permitting, the author states that key barriers include general lack of experience with hydrogen, public resistance to development, and an absence of clear, hydrogen-specific planning guidance. The author concludes that uncertainty about a future hydrogen economy and its market dynamics will not prohibit its domination in future decarbonized power systems.

WHAT ARE THE ECONOMIC RISKS ASSOCIATED WITH INVESTING IN ENERGY STORAGE, AND HOW CAN THEY BE MITIGATED?

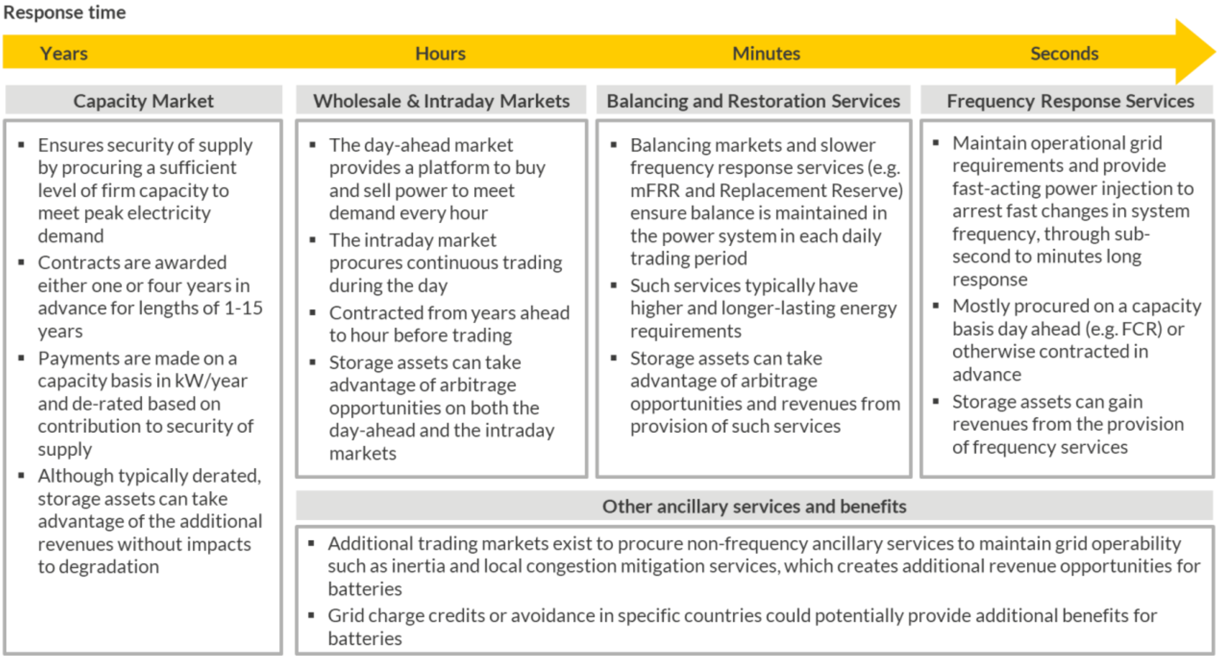
Alexandre Danthine and Alejandro Zerain

Energy storage is expected to play a crucial role in the energy transition over the upcoming decades. The increasing penetration of intermittent renewables and the expected phase-out of thermal generation set a new challenge to decarbonize our power systems. There is an increasing need for technologies to provide firm and flexible capacity to meet security-of-supply standards and to provide services to the grid that have been traditionally met by thermal generation. Energy storage assets, such as lithium-ion batteries, will play a significant role in providing these services.

To understand the risks associated with investing in energy storage, it is important to first understand the business model of grid-scale front-of-the-meter energy storage. (The business case for behind-the-meter storage assets and their associated risks differs, as other variables in addition to energy arbitrage play a role in dispatch optimization—for example, maximization of self-generation and retail cost minimization through load shifting.)

Front-of-the-meter assets typically follow a merchant model, where their revenues are stacked by combining energy arbitrage in wholesale markets, providing ancillary services to the system, and receiving capacity market payments if available. Which markets storage assets participate in ultimately depends on their availability and design in each country. Figure 1 provides an overview of the potential available markets.

Figure 1: Markets for energy storage



Source: Aurora Energy Research— Böhmer, D., Fenske, C., Lorenz, C., and Westbroek, M. (2 June 2023), Long-Duration Energy Storage: Regulatory Environment and Business Models in Germany, Spain, France, Italy and Great Britain. https://auroraer.com/insight/long-duration-energy-storage-ldes-regulatory-environment-and-business-models-in-germany-spain-france-italy-and-great-britain/

Energy storage assets carry out energy arbitrage in the wholesale market by buying electricity when prices are low and selling it when prices are high, earning a profit from the difference between the purchase price and the sale price. The revenue potential of wholesale market arbitrage depends on the spreads between bottom and top prices. As a result, energy storage assets are heavily exposed to merchant risks and market fundamentals.

Storage assets can also play a role in providing balancing and frequency response services due to their ability to balance the load on the grid in both directions (absorbing power when the frequency is too high and discharging when the frequency is too low). To participate in balancing and frequency services markets, assets must meet technical requirements such as minimum response times, ramp rates, and availability criteria.

Wholesale market fundamentals

The development of high and low prices in turn is determined by a variety of factors such as prices for commodities used for electricity generation, electricity demand, the buildout of renewable capacity, and the amount of flexibility in the system. Figure 2 provides an overview of the main drivers and commentary on their impact.

Figure 2: Drivers of price volatility and impact

Drivers of price volatility		Impact
Renewable penetration	Increasing renewable deployment will result in higher frequency of low prices	↑
Decrease in commodity prices	A potential decrease in commodity prices in the medium term will translate into less volatility in power prices	↓
Flexible generation	The deployment of energy storage will cannibalize spreads as assets will follow the same dispatch behaviour	↓
Flexible demand	Flexible demand would increase consumption in hours with low prices and reduce peak demand	↓
Interconnections	Additional integration would allow markets to export excess generation and import cheap electricity in periods of high demand	↓
Retirement of thermal generation	The retirement of baseload capacity would increase price volatility	↑

Sources: Aurora Energy Research (17 July 2023), *Long Duration Energy Storage in Spain*, https://auroraer.com/insight/long-duration-energy-energy-storage-in-spain/, pp. 22, 23, 48; Aurora Energy Research (15 June 2023), *French Power Market Annual Outlook and Market Consensus*, https://auroraer.com/insight-type/webinar-recording/french-power-market-annual-outlook-and-market-consensus/, p. 13; Aurora Energy Research (5 July 2022), *Prospects for Long Duration Energy Storage in Germany*, https://auroraer.com/insight/prospects-for-long-duration-energy-storage-in-germany/, pp. 18 and 28.

One of the key economic risks for energy storage is that with an increasing amount of flexibility in the system, prices stabilize, reducing the spreads available for energy arbitrage. The deployment of energy storage assets will increasingly cannibalize price spreads, as these assets will follow a similar behaviour (charging at low prices and discharging at high prices). Moreover, flexible demand will also contribute to reduced price volatility and negatively impact the business case for energy storage assets. Smart electric vehicles and flexible electrolysers will consume electricity in response to low price, serving as a load sink and reducing the frequency of hours with low prices. Similarly, flexible demand will shift their consumption from peak hours with high prices, contributing to the reduction of high price instances. These developments are positive for the overall system and will help to integrate intermittent renewable generation, but can pose an economic risk for energy storage investors relying on energy arbitrage.

Energy storage assets typically do not rely only on wholesale market arbitrage but also participate in a range of ancillary services to stack their revenues. These markets are attractive and well suited for storage technologies such as lithium-ion batteries as they require a fast response. However, these markets tend to be small, and the increased deployment of storage assets may saturate them. Given the low marginal cost of storage assets compared to thermal generation providing these services, prices would drop significantly as the number of batteries in the system increases. The experience in France and Germany with the frequency containment reserve (FCR) in recent years is a clear example.

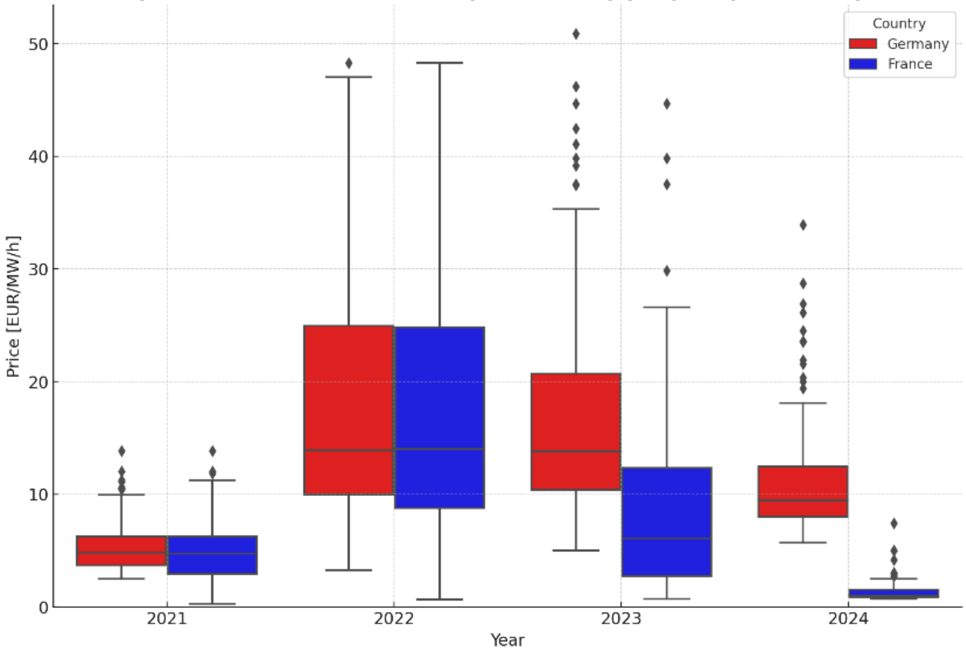
Frequency containment reserve—has the market reached full saturation?

FCR, also known as the primary reserve, plays a crucial role in maintaining the electrical grid's stability by ensuring that the frequency remains at its nominal value, which is 50 Hz in Europe. To achieve that, the primary reserve is activated within 30 seconds up to 15 minutes. Due to the fast response required for this service, batteries are well designed to fill this need. Nonetheless, the needs are quite limited—3 GW for the whole of continental Europe, and 1.5 GW for the FCR cooperation within which the requirements can be exchanged—making it a shallow market.

As of January 2024, the countries participating in FCR are Austria, Belgium, Switzerland, Germany, western Denmark, France, the Netherlands, Slovenia, and the Czech Republic. In Germany and France, the largest markets for FCR, the annual demand is approximately 600 MW for Germany and 500 MW for France, each hour of the year.[1] These countries have the option to export a portion of their FCR supply to other members of the FCR cooperation.

While FCR prices in Germany and France remained comparable until November 2022, there has been a noticeable divergence in 2023 and 2024. By the end of 2023, despite Germany having a significantly greater installed battery capacity (1,147 MW) than France (796 MW),[2] France experienced a more pronounced market saturation. Figure 3 shows the distribution of FCR prices in Germany and France in January from 2021 to 2024. FCR prices in both countries diverged as of 2023, showing a significant drop in French prices with nearly no variation in 2024, indicating that the market is saturated.

Figure 3: Distribution of FCR prices in France and Germany for January per year (2021–2024)



Source: Elaborated by the authors with data from German transmission system operators 50hertz, Amprion, TenneT and TransnetBW (2024); https://www.regelleistung.net/.

Note: In this boxplot, the whiskers extend to the furthest points within 1.5 times the interquartile range from the first and third quartiles, respectively. The interquartile range is the difference between the third and first quartile values, representing the middle 50 per cent of the data. Any data points outside this range are considered outliers and are depicted as individual points beyond the whiskers.

The saturation of FCR in France and price divergence with Germany can be attributed to two main factors. Firstly, France's energy supply has a larger share of low-marginal-cost sources, such as run-of-river hydroelectricity and nuclear power, than Germany. Secondly, unlike Germany, which can leverage batteries for secondary reserve capacity and energy markets, French batteries have fewer opportunities for revenue stacking.

This illustrates the risk of market saturation within limited ancillary service markets and underscores the need for revenue diversification for batteries to achieve profitability. Several ancillary services in Europe are still not liberalized, with the secondary reserve capacity reservation in France being one of them.

[1] Data from German transmission system operators 50hertz, Amprion, TenneT and TransnetBW (2024); https://www.regelleistung.net/.
[2] Data (2024) from the French transmission system operator (RTE – réseau de transport de l'électricité); https://opendata.reseaux-energies.fr/ and Marktstammdatenregister; https://www.marktstammdatenregister.de/MaStR.

Regulatory uncertainty and lack of framework

Investors in energy storage face significant regulatory risks under current market conditions, identified as follows:

- ambiguity in market rules and participation requirements
- new national and EU laws that undermine energy storage's economic viability
- market design developments affecting energy storage's revenue potential.

Energy storage and market participation rules lack clarity in several European markets. For instance, in Spain, it is uncertain whether batteries co-located with renewable assets in DC coupling can charge from the grid, or whether these co-located assets can participate in ancillary services during renewable imbalances without bearing imbalance costs, potentially causing them to miss out on more profitable actions.

The introduction of national and EU legislation can impact energy storage assets negatively. In 2023, the European Commission approved an amendment to the General Block Exemption Regulation, exempting subsidy schemes for co-located storage from state aid notification as long as 75 per cent of its energy comes from the renewable asset on an annual basis.[3] This requirement could slow down the introduction of support schemes for storage across Europe. It would also limit the storage operations for awarded projects and introduce compliance uncertainty for support schemes exempt from state aid approval.

Positive developments in market rules and integration of the European electricity market can also have an uncertain impact on the energy storage business model. Under the Single Day-Ahead Coupling, the market time granularity will change from 1 hour to 15 minutes.[4] While this measure would increase trading opportunities for storage, it would also enhance market efficiency, decreasing the demand for ancillary services.

Mitigation strategies: long-term revenue certainty and portfolio diversification

Fortunately, there are several mitigation strategies that energy storage investors can resort to. Long-term stable and predictable revenues improve the bankability of energy storage projects and help investors to reduce the cost of capital associated with these projects. There are several forms in which long-term visibility of revenues can be achieved.

Governments are well placed to design markets and technology-neutral support schemes that can provide long-term revenue certainty to energy storage investments. Several examples in Europe are worth mentioning:

- Capacity markets allow energy storage assets to secure a long-term capacity contract for their contribution to the security of supply. Several European countries already have capacity markets where batteries operate, and the length of the contracts varies across markets. Great Britain, Poland, Belgium, and Italy offer contracts of up to 15 years for newly built assets. Ireland offers 10-year contracts for newly built assets, while France operates a one-year decentralized capacity market.
- Greece recently implemented a two-way contract-for-difference auction scheme providing revenue certainty.[5] Investors bid for 10-year annual payments ('reference revenues'), in addition to receiving a defined initial investment grant. Each year, the authority estimates *ex ante* the revenues of each asset and provides an annual payment as the difference between the estimated revenues and the reference revenues. *Ex post*, each asset receives an additional settlement based on the difference between the estimated revenues and the actual average revenues of comparable assets. (Projects awarded with a contract will be grouped with similar assets operating in the Greek market—both merchant assets and those under a contract for difference. These assets will serve as a benchmark to create an additional incentive to operate efficiently, while correcting any potential over- or under-estimation of the revenues *ex ante*.)
- The UK Department for Energy Security & Net Zero launched a consultation on long-duration electricity storage in January 2024, seeking to evaluate design proposals for a cap-and-floor regime to support investments.[6] A cap-and-floor scheme provides a minimum revenue certainty for investors to provide debt security, and a regulated limit on

[3] General Block Exemption Regulation (GBER), amended by Regulation (EU) No 2023/1315, Article 41; https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32023R1315.
[4] Nemo Committee, 'Single day-ahead coupling (SDAC)', https://www.nemo-committee.eu/sdac.
[5] European Commission, State Aid Decision SA.64736—RRF - Greece - Financial support in favour of electricity storage facilities, 5.9.2022; https://ec.europa.eu/commission/presscorner/detail/en/ip_22_4582.
[6] UK Department for Energy Security & Net Zero (January 2024), *Long Duration Electricity Storage Consultation: Designing a Policy Framework to Enable Investment in Long Duration Electricity Storage*; https://assets.publishing.service.gov.uk/media/659bde4dd7737c000ef3351a/long-duration-electricity-storage-policy-framework-consultation.pdf.

revenues to avoid excessive returns. This type of scheme reduces overall investment risks and puts downward pressures on the cost of capital. An appropriately designed scheme would incentivize projects to act flexibly in response to market signals and provide maximal benefit to the power system.

However, while support schemes can help the deployment of energy storage technologies that can bring benefits to the overall system by improving bankability, these measures should not replace the introduction of markets that appropriately value the needs of the system. Remunerating services such as frequency restoration reserves and other non-frequency services (such as inertia, voltage control, and black start) would not only improve the business case of energy storage assets but also mitigate some of the existing risks of energy storage assets through revenue diversification.

There are strategies that investors can undertake to secure long-term revenue certainty. Arrangements with route-to-market providers allow energy storage investors to de-risk the complex trading optimization of battery dispatch by outsourcing battery trading operations. In some arrangements, investors can secure a revenue floor in exchange for a profit upside. There are typically two types of profit-sharing arrangements with route-to-market providers:

- Profit sharing with merchant revenues allows a provider to optimize the dispatch of the battery in exchange for a percentage of the merchant revenues. This type of contracting de-risks the operation of the battery; but by relying fully on merchant revenues, it exposes the returns to market fundamentals and the risks highlighted above.
- Profit sharing with a revenue floor provides a guaranteed level of contracted income to projects, enabling bankability. However, the level of protection may come at a high cost to asset owners, as the fee tends be higher than in a project with merchant revenues only.

Co-location of energy storage with renewable sources can also unlock long-term, stable, and predictable revenues in the form of power purchase agreements (PPAs). Projects with renewable assets co-located with energy storage can secure the sale of electricity for their generation at an agreed price over a long-term period. The inclusion of energy storage can open the possibility to sign PPAs with baseload or fixed profiles, which trade at a premium compared to pay-as-produced PPAs, while also reducing the volume risk associated with PPAs requiring volume commitments.

As a mitigation strategy, co-location of energy storage with renewable assets also provides revenue and portfolio diversification. In the case of solar PV and batteries, the generation profiles of these technologies tend to be complementary. Solar PV assets generate in the middle of the day, when prices tend to be low, while storage assets charge at low prices and discharge at high prices, typically when solar PV is not generating. As a result, co-location of these technologies can help to maximize the use of the grid connection with limited impact on the dispatch operation of each asset.

Portfolio diversification can help to mitigate the specific risks of each technology. Increasing renewable penetration would lead to solar PV cannibalization (lower prices) but result in higher price volatility, benefitting the battery business case. Conversely, increasing flexible generation and demand would reduce price spreads available for storage assets, while raising electricity prices in hours when the solar PV asset generates.

In the end, the attractiveness of co-location will depend on the storage investment costs and the idiosyncrasies of each market (e.g. renewable penetration, regulatory framework, and available markets).

All hands on deck

There is consensus that energy storage will play a key role in integrating renewables and providing security of supply to the power system, but words do not always translate into actions, and targets do not equate to measures. If national plans include ambitious storage targets, policymakers must implement sound support mechanisms and incentives that allow for revenue diversification and provide long-term revenue certainty. These measures will help to incentivize investment and lower the cost of capital.

On the other hand, markets must provide innovative solutions to enhance bankability for a nascent technology. Some of these solutions include long-term revenue contracting (in the form of profit-sharing arrangements and PPAs), but diversification (in terms of revenue stacking and portfolio) will also be crucial. In the end, these efforts to deploy energy storage technologies represent two sides of the same coin.

RISK HEDGING VIA COLLARS: A NEW MODEL FOR COMPLETING STORAGE MARKETS?

Farhad Billimoria

While the core elements of the original design of Australia's National Electricity Market (NEM) remain strong, it will likely represent a backdrop to the front-stage panoply of tendering mechanisms and contracting frameworks that are set to drive the investment decisions required to decarbonize the country's electricity infrastructure.

For much of the past decade, in the absence of strong federal policy on the matter, states have sought their own destiny in terms of renewable energy targets, the scale of firming investment required, and the mechanisms to achieve them. Therefore, what has emerged has been a patchwork of state and federal schemes that vary in tendering approaches, contractual structures, government funding, and selection criteria. The facilitation of electricity storage and firming resource investment is an important microcosm of the broader issue. Included in the schemes that facilitate storage are tenders for centrally initiated risk hedging contracts (most notably in New South Wales), state-based contracting with storage for the provision of system security services (across many regions including New South Wales, Victoria, and South Australia), and direct government investment in large and long-duration storage facilities (in Queensland and by the federal government).

Recently, the federal government has introduced the Capacity Investment Scheme (CIS), an attempt at a unifying approach to driving investment required for meeting Australia's climate ambitions in the electricity sector.[7] This scheme will facilitate 23 GW of renewables and 9 GW of storage, via a set of regional but consistent tenders for long-term risk hedging contracts. This was recently expanded from a much smaller targeted scheme with a total 6 GW of appetite.

The CIS can be seen as a form of central risk hedging for long-term resource capacity, as opposed to other central auction mechanisms that establish a separate product for 'capacity' or similar.[8] Putting aside the debate on the appropriateness of centralized versus decentralized forms of risk hedging, this article considers one of the more unique aspects of the CIS: the contract form.[9] The CIS is implemented through a 'collar' instrument—also referred to as a combination of caps and floors. This article reviews the appropriateness of collars as a means of hedging risk for storage investments, concluding that collars have significant potential as a means of de-risking storage. It also highlights some of the more complex implementation challenges that require further consideration and research.

Contract structure and form of the risk hedge

As electricity systems around the world transition towards lower-carbon resources, a key question for electricity markets is how derivative and risk-hedging contracts should be redesigned to suit such resources. For traditional forms of fossil-based generation, fixed-volume swaps and caps (call options) have been popular trading instruments on decentralized derivatives exchanges. The design of centralized capacity mechanisms too has centred on a call option style design, either directly under the terminology of a 'reliability option' or indirectly via other performance penalty schemes.

However, questions have been raised as to the suitability of such structures in a market with high penetrations of renewables and storage. One criticism concludes that the call option, when combined with marginally priced spot markets, creates an asymmetry in payoffs that biases against low-variable-cost, high-capital-cost resources such as renewables and storage.[10] Thus, the question of what replaces this contract is up for debate.

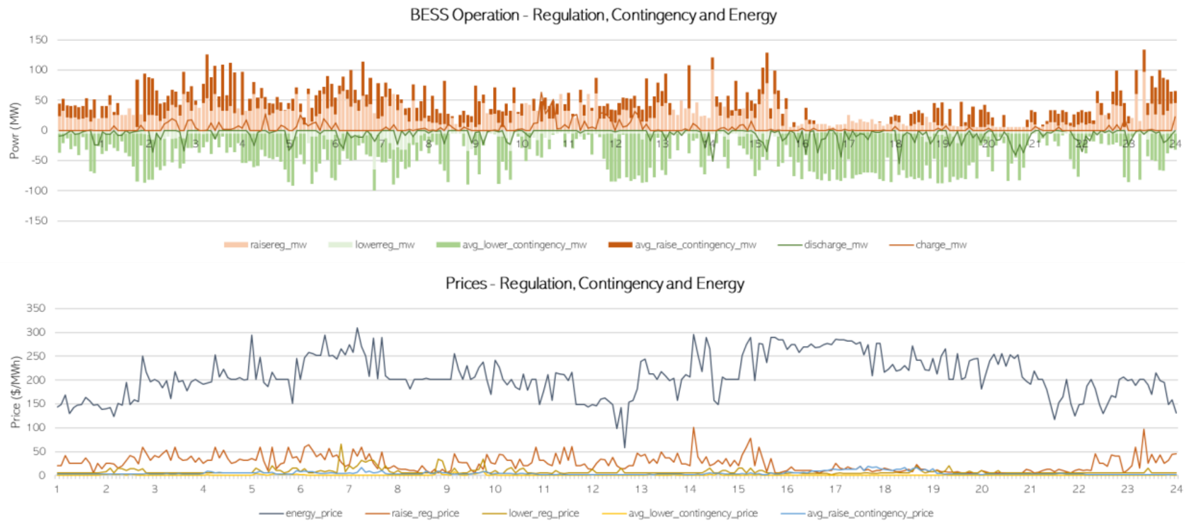
A range of contract forms have been considered in industry and in the academic literature. As an extension of traditional reliability options, an affordability option has been proposed that involves an option with the payout as the difference between the strike and a weighted average price over a longer period.[11] Alternatively, forward or swap contracts do not have any

[7] See AEMO Services, *The Capacity Investment Scheme*, https://aemoservices.com.au/tenders/capacity-investment-scheme.
[8] W.W. Hogan (2022), 'Electricity market design and zero marginal cost generation', *Current Sustainable/Renewable Energy Reports*, 1–22.
[9] Readers interested in the debates on missing markets are referred to the following works: Mays, J., Craig, M.T., Kiesling, L., Macey, J.C., Shaffer, B., and Shu, H. (2022), 'Private risk and social resilience in liberalized electricity markets', *Joule*, 6(2), 369–380; Hogan, W.W. (2022), 'Electricity market design and zero-marginal cost generation', *Current Sustainable/Renewable Energy Reports*, 9(1), 15–26; Newbery, D. (2018), 'Missing money and missing markets in the electricity industry', in *Toward a Just Society: Joseph Stiglitz and Twenty-First Century Economics*, Columbia University Press, pp. 131–158.
[10] Mays, J., Morton, D.P., and O'Neill, R.P. (2019), 'Asymmetric risk and fuel neutrality in electricity capacity markets', *Nature Energy*, 4(11), 948–956.
[11] Bhagwat, P.C., and Meeus, L. (2019), 'Reliability options: Can they deliver on their promises?', *The Electricity Journal*, 32(10), 106667; Schittekatte, T., and Batlle, C. (2023), 'Assuring a sustainable decarbonization: affordability options, *IEEE Power and Energy Magazine*, 21(4), 72–79.

optionality, and involve the exchange of a fixed price for the weighted spot price over a period (e.g. a year). A specific proposal in this regard is the standardized fixed-price forward contract, which involves a load-weighted forward contract over a set period.[12]

Many of the principles relevant to selecting an optimal contract form are consistent across generation and storage—including incentive compatibility with spot market signals, limiting distortion to existing derivative and contract markets, avoiding moral hazards, and efficient procurement. However, there are also factors specific to storage that require consideration. The multidimensional nature of battery storage complicates the design of an optimal contract. Where generation is unidirectional, storage operations require the management of bidirectional energy flows (charge and discharge). Storage also participates in multiple ancillary service markets that are co-optimized with energy. As such, the dominant form of revenue for storage can vary significantly over time periods (see Figure 1).

Figure 1: Example of intra-day dispatch of a Battery Energy Storage System (BESS) in the National Electricity Market



Source: Billimoria, F., and Simshauser, P. (2023), 'Contract design for storage in hybrid electricity markets', *Joule* 7(8), 1663–1674.

The collar or cap-and-floor contract has been raised as a potential contractual structure well suited to storage investment. It is the design explicitly adopted by the Commonwealth of Australia's CIS, which considers both renewables and storage under the same broad contract structure. Such a structure is implicit in the tenders for long-term energy service agreements across renewable energy zones run by the New South Wales government. In this program, contracts take the form of multiple shorter-term options to receive a variable annuity payment, exercisable in advance, with revenue caps and maximum payment limits.

In the UK, the cap-and-floor approach is being considered in detail by the Department of Energy Security and Net Zero as a means of facilitating long-duration and novel storage investments. The UK scheme appears to have been motivated by the adoption of a similar structure for supporting new interconnector projects connecting to the UK market.[13] Elements of the collar contract form also appear implicit in the 'two-sided' contract-for-difference structure being implemented by the EU and member countries.[14]

While the collar has been highlighted in some jurisdictions (such as in New South Wales and the UK) as a storage-specific contract structure, in many others it is being considered more broadly as a means of providing revenue support to renewables investments too (most notably the CIS in Australia, and two-way contracts for difference in Europe). Interestingly for the CIS,

[12] Wolak, F.A. (2022), 'Long-term resource adequacy in wholesale electricity markets with significant intermittent renewables', *Environmental and Energy Policy and the Economy*, 3(1), 155–220.
[13] See for example, Office of Gas and Electricity Markets (2021), *Cap and Floor Regime Handbook*. https://www.ofgem.gov.uk/publications/cap-and-floor-regime-handbook
[14] See AEMO Services (2023), *Long Term Energy Services Agreements*, https://aemoservices.com.au/products/ltesa; Department of Energy Security and Net Zero (2024) Long Duration Energy Storage: proposals to enable investment, https://www.gov.uk/government/consultations/long-duration-electricity-storage-proposals-to-enable-investment; Morawiecka, M., and Scott, D. (2023), 'Balancing act: two-sided contracts for difference for a speedy, cost-efficient and equitable energy transition', Regulatory Assistance Project, https://blueprint.raponline.org/deep-dive/contracts-for-difference/.

there is also the potential for demand response or other 'clean firm' resources to be successfully awarded collar contracts. The latter has been increasingly relevant as the deployment of more renewables has forced spot prices to go negative in renewables-heavy periods in many markets.

What is the collar?

The collar is a contract is between a storage resource and a counterparty (such as a government agency in a centralized framework, or a risk trader in a decentralized framework). It is a combination of a series of call options (termed a cap) and put options (termed a floor), referenced against the gross margin earned by a storage facility over a set period (e.g. a year). The gross margin is defined as total revenues (including energy and ancillary service revenues) minus total operating costs (including energy costs). The storage resource purchases a floor and sells a cap, and the counterparty does the opposite. For every annual period, the seller of the cap pays either the difference between the actual gross margin of the storage facility and a set threshold (termed the cap strike price), or zero, whichever is greater. For the same period, the buyer of the cap receives either the difference between a set threshold (termed the floor strike price) and the actual gross margin of the storage facility or zero, whichever is greater.

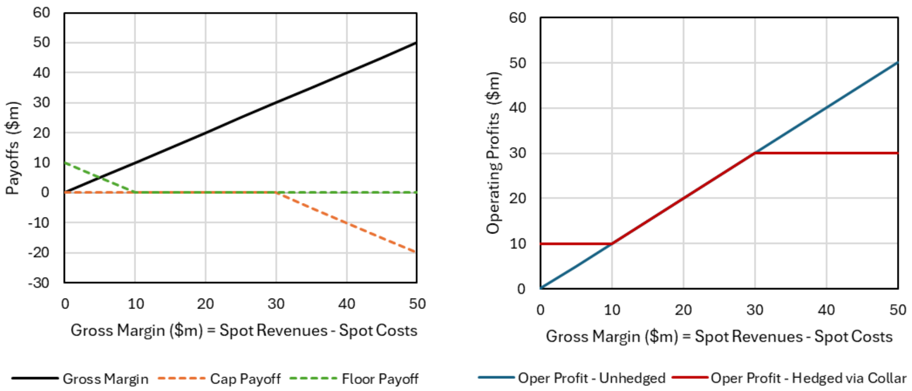
When combined with the gross margin received from wholesale markets, the instrument guarantees the storage resource a minimum operating profit while setting a maximum operating profit. In this way, it provides downside protection to a resource in return for forging upside above a particular threshold.

A sample calculation of the operation of a collar over an annual period is shown in Table 1 and Figure 2. The left panel of Figure 2 illustrates how the payoffs for the cap and floor instruments vary with the wholesale gross margin. The right panel illustrates the gross margin against the operating profits for an unhedged and hedged storage facility.

Table 1: Sample calculation of the operating profits of a storage facility during a single operating period—unhedged, and hedged via a collar on annual gross margins with a floor strike of $10 million and a cap strike of $30 million

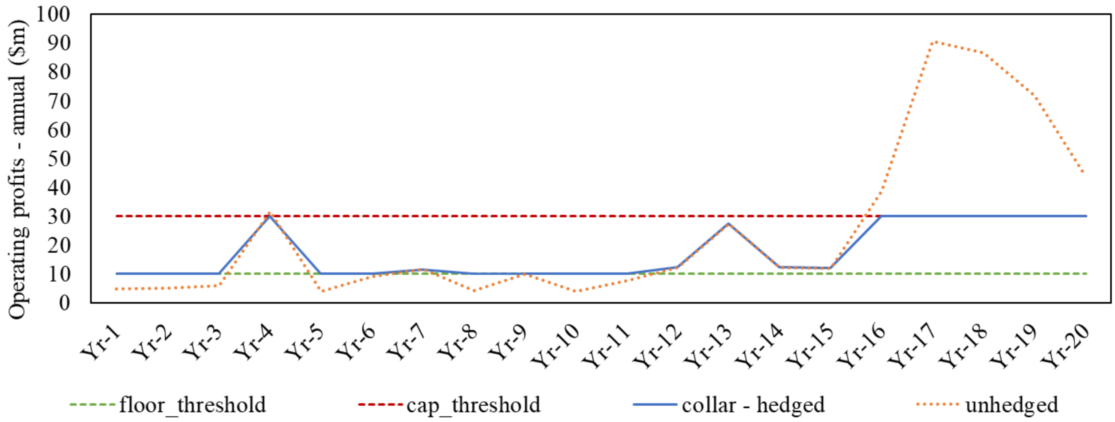
Annual Gross Margin	**Unhedged**	**Hedged with Collar Floor Strike: $10m, Cap Strike: $30m**			
	Operating Profit	*Gross Margin*	*Cap Payoff*	*Floor Payoff*	*Operating Profit*
0	0	0	0	10	10
10	10	10	0	0	10
20	20	20	0	0	20
30	30	30	0	0	30
40	40	40	-10	0	30

Figure 2: Sample illustration of the operating profits of a storage facility during a single operating period—unhedged, and hedged via a collar on annual gross margins with a floor strike of $10 million and a cap strike of $30 million



While the illustration above shows payoffs for a single operating period, the collaring of operating profits over the tenor of the collar instrument is shown in Figure 3. It can be observed that, while the collar works to limit operating profits to upside and downside thresholds, it allows the resource to continue to optimize margins within those bounds.

Figure 3: Sample illustration of the operating profits of a storage facility over the life of the collar instrument—unhedged, and hedged via a collar on annual gross margins with a floor strike of $10 million and a cap strike of $30 million



Benefits of the collar

A revenue collar has several desirable attributes in the context of energy storage. The net revenue to which the collar applies extends over a set period (say a quarter or year). This preserves the short-term operational incentives of the storage unit to continue to profit-maximize and participate optimally in the spot market. This includes not just energy markets but also ancillary service markets, thereby preserving the multi-attribute value of storage. There are some important threshold effects to consider here, which will be discussed below.

Adopting a broader definition of revenue, which includes external contracts, provides opportunities at a high level for the storage project to continue to contract via private risk-trading markets. This could be argued to be less distortionary than contract structures that eliminate or limit such incentives. However, further research is required on the interventionary impacts of collars, especially as compared to other instruments such as reliability options, affordability options, and standardized fixed-price forward contracts.

Other advantages include the following:

- alignment with standard project financing structures (with the floor threshold likely sized to meet any mandatory financing payments, such as debt service, and the cap threshold sized to limit windfall profits)
- opportunities for governments and central agencies to redistribute windfall profits if the cap threshold is reached
- operating flexibility (the instrument only applies to gross margins over a whole-of-period basis, e.g. a year, or quarter in aggregate, and does not mandate any specific behaviour during dispatch intervals, hence preserving operating flexibility)
- opportunities for participation in multiple markets including grid/ancillary services, network services, and local markets.

Complexities and structural considerations

Other issues related to the collar mechanism require careful design consideration and further research:

- Risk profile and liability exposures of the counterparty need careful assessment—more so under centralized procurement, as the public will be bearing the risk exposures.
- Procedures are needed to redistribute windfall gains to consumers under centralized mechanisms.
- Auction clearing is more complicated for a multi-parameter instrument. To date, most programs utilizing collars have used an administrative selection procedure rather than a market clearing.
- Price formation for auctions of collar instruments will require a choice between pay-as-bid and single price clearing.

- Electricity prices can be fat tailed and positively skewed, which means they can be exposed to periods of extreme scarcity and high price spikes. This needs to be considered in risk exposures for projects and counterparties.
- Impact on the system mix needs to be considered, given the scale of programs contemplated. The decisions made by the central agency on resource mix will significantly affect prices and cashflows for all participants in the system.
- Decision-making by and governance of the central agency—its objectives and scope, risk standards, capital budgets, probity, and political influence—will have a substantial effect on outcomes.
- Cap or floor thresholds, once reached or expected to be reached, will affect the incentives of the storage unit in the market. For this reason, a pure ‘hard cap’ on revenues should be avoided and instead substituted with upside revenue sharing. The floor side of the revenue collar protects the project from the risk of low spot revenues, which may lead to underachievement if the floor is guaranteed. Further research on performance criteria and incentives is required.[15]
- Strategic and competitive effects may extend beyond the individual project to which a collar applies, because the project may be part of a larger resource portfolio. As such, research is required on the competitive effect of the collar instrument under a strategic setting or in a concentrated market.

More broadly, governments that go down the expanded risk-hedging route will inevitably need to deal with the issue of competition for subsidies. If only certain assets (e.g. storage) are eligible for support, this could shorten the time frame for retirement of large and lumpy fossil generation units. Does the government allow such units to retire, notwithstanding that this may create reliability problems—whether in actuality, perception, or imagination? Heeding such calls for subsidy may indeed be a slippery slope. When implemented at scale, the mechanism then faces the additional challenge of ‘becoming the market’, subject to multiple competing appeals for support. Finally, the development of risk-hedging mechanisms does not avoid the imperative of creating full-strength short-term signals. As such, the internalization of the emissions externality should be an immediate priority for electricity market design.

Conclusion

The revenue collar represents an interesting contractual structure for risk-hedging mechanisms in low-carbon markets. By providing a cap and floor over longer periods, it could be less distortionary than contract forms that apply over individual dispatch intervals. This may make it suitable to manage the rapid investment scale-up required in resources with different cost structures, such as storage. As it is a more complex form of derivative instrument, several guard rails will be needed in the structure. Finally, while it has the potential to be less interventionist, much further research is needed on contract design and implementation.

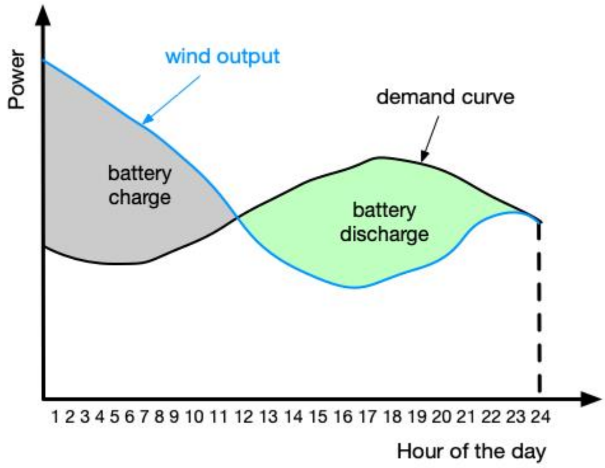
COUPLING STORAGE AND RENEWABLES: IN THE PHYSICAL OR VIRTUAL WORLD?

Dimitra Apostolopoulou and Rahmat Poudineh

The idea of combining different technologies, such as storage and renewable resources, stems from the fact that their complementary characteristics can benefit the aggregate system. Complementarity may refer, for example, to using the excess generation from a wind farm to charge a storage system when there is insufficient demand and discharging it when demand is high and wind farm output is low, as depicted in Figure 1. As the figure shows, the combination of storage with renewable resources is a natural choice, since they have complementary characteristics in terms of variability and controllability.

[15] See Billimoria, F., and Simshauser, P. (2023), ‘Contract design for storage in hybrid electricity markets’, *Joule* 7(8), 1663–1674.

Figure 1: Wind and battery complementary characteristics



In recent years, the idea of complementarity has been applied in projects that also share location, i.e. are co-located. Co-located aggregate projects can be linked only locationally or also operationally. We refer to these options as operationally independent or integrated, respectively. The motivation behind co-located aggregate projects is to take advantage of complementary characteristics as well as benefits from co-locating two resources—for example, in easing the permitting process.

In the United Kingdom (UK) there has been a high interest in such projects; in the first quarter of 2023, the volume of applications for co-located photovoltaic (PV) and storage projects significantly outgrew those of stand-alone PV installations.[16] This trend is also observed in Europe, where almost 15 per cent of industry experts believe that storage capacity is critical to manage renewable energy risks.[17]

Aggregate co-located storage and renewable resources are also increasingly common in the United States (US), where a third of proposed PV capacity now includes battery storage.[18] However, there is locational variability in the uptake of such projects. For example, on the west coast 70–90 per cent of new PV installations are paired with storage, compared with 5–20 per cent on the east coast. This suggests that there is no right fit for all, and that co-location might not be the best choice under all conditions.

Co-location is not the only way to couple storage and renewable energy resources. Another possibility is to couple them operationally while they are locationally separate. Facilities structured in this way are called virtual power plants (VPPs). There are many VPPs; for example, in 2018 Tesla in collaboration with the South Australian government and the local electricity provider proposed the development of a 250 MW VPP that comprises a network of rooftop PV (5 kW) and battery storage systems (5 kW/13.5 kWh) installed on public housing, which aims to achieve $65 million per year savings across all South Australian customers.

The increased interest in co-located aggregate projects stems mainly from the favourable regulatory framework for them. However, as discussed below, they also have several drawbacks. This paper argues that, instead of designing the regulatory framework to favour co-located aggregate projects, both the regulatory and market frameworks should be carefully rethought to support the construction of either co-located projects or VPPs, whichever is most beneficial for the system.

Co-located aggregate systems

There are several benefits of co-locating storage and renewable resources. For example, it enables the provision of additional services, lowers the cost at which services can be provided in electricity markets, and saves on shared engineering, customer and site acquisition, permitting, and labour, while it allows for a shared transmission interconnection compared to developing the projects separately. It also provides reliable, dispatchable energy to the local microgrid—enhancing grid resilience (the ability to withstand, respond to, and recover rapidly from disruptions) and ensuring power supply to critical loads during major physical or cyber disruptions.

[16] Pexapark (2023), *Renewables-Plus-Storage Co-location Trends: Hybrid PPAs and More*.
[17] Pexapark (2023), *Renewable Industry Survey*.
[18] Lawrence Berkeley National Laboratory (2023), 'Grid connection requests grow by 40 per cent in 2022 as clean energy surges, despite backlogs and uncertainty'.

With integrated co-location, the overall value that can be captured by the aggregate system in energy markets, forward capacity markets, and/or ancillary service markets increases. The synergies between renewable generation and storage are well documented. In terms of energy arbitrage, storage can compensate for forecast errors and short-duration fluctuations, thus avoiding imbalance penalties. Also, integrated co-location projects may be used for shifting renewable output to higher-value periods, thus increasing the average value of energy sold.

Storage reduces total curtailments of generation from renewable sources. In terms of ancillary services, it enables inertial support and frequency responses during transitions between grid-connected and islanded modes of the aggregate system. The dual nature of storage (consuming and generating), combined with renewable resources, can result in an integrated co-located system that improves grid stability by injecting or absorbing real and reactive power to support frequency and voltage stability. Furthermore, these aggregate (operationally integrated) systems have a high-capacity value based on the individual value contribution to resource adequacy but also because storage prevents renewable generation curtailment, thus making their usage more efficient.

In addition to this, if the integrated co-located project is sharing components, then it further enhances economic benefits. For example, in a PV and battery hybrid, a shared bidirectional inverter enables recovered clipping (when PV generation exceeds the inverter capacity limit, it is 'clipped' by the inverter), low-voltage harvesting (some PV generation is collected at voltages below the minimum rating for the inverter, e.g. during sunrise, sunset, and very cloudy periods), and potentially higher round-trip efficiencies for charging and discharging the battery.

However, there are several drawbacks to co-located aggregate projects. For instance, co-location limits the potential locations at which storage might be sited. This leads to an opportunity cost—the missed value that could be realized by independently siting storage in an optimal location away from renewable resources. A study in the US called this opportunity cost a 'coupling penalty' and quantified it at $2.3–13.7/MWh.[19] This penalty is the same order of magnitude as cost savings estimates for aggregate projects' development and construction. This rough equivalence in opportunity cost and cost savings suggests that the net value of co-located aggregate systems is highly sensitive to regional market conditions and configuration decisions. In the case of operationally independent co-location, storage operation is also restricted by the shared capacity interconnection. In integrated co-location, on the other hand, there may be additional constraints of sharing an inverter or grid interconnection capacity—which can reduce an aggregate project's ability to schedule services during the highest-value times or place restrictions on grid charging due, for example, to requirements to charge from the renewable resource as indicated in some policies.

Virtual power plants

When co-locating an aggregated project, it is inevitable that at least one of its components will be positioned in a less than ideal location compared to scenarios where each component is sited independently. Research conducted in both the UK and the US indicates that co-located storage and renewable energy systems lack viability without the support of regulatory frameworks that offer financial incentives.

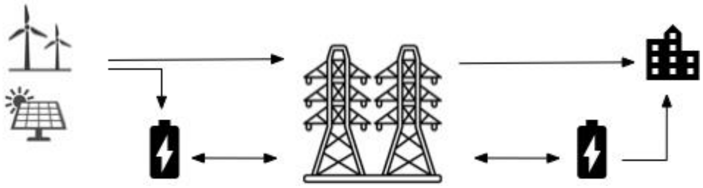
An alternative approach involves virtual co-location of storage and renewable generation—the VPP. VPPs are aggregations of distributed energy resources that can balance electrical loads and provide utility-scale and utility-grade grid services like a traditional power plant. They share all the benefits of integrated co-location except for the ones that stem from physical co-location. As such, they can offer several benefits to the system—reducing the cost of electricity by decreasing reliance on expensive peaking units, and reducing greenhouse gas emissions by expanding grid capacity and absorbing higher shares of renewable energy. For example, 400 MW of VPP consisting of smart thermostats, electric vehicle chargers, smart water heaters, and behind-the-meter batteries can replace a natural gas peaking plant or a transmission-connected utility-scale battery. Moreover, 60 GW of VPP can address resources adequacy needs costing $15–35 billion less than other options. Adding that much VPP capacity would also result in $20 billion in societal benefits in the form of resilience and lower carbon emissions over 10 years.[20]

As depicted in Figure 2, a VPP can also involve storage resources near renewable generation and/or load centres. If they are located near renewable generation, VPPs can also be seen as virtual lines that reduce renewable generation curtailment due to grid congestion. VPPs in this case are faster and more flexible than network reinforcement. However, the regional regulatory

[19] Gorman, W. et al. (2022), 'Are coupled renewable-battery power plants more valuable than independently sited installations?', *Energy Economics*, 107.
[20] The Brattle Group (2023), *Real Reliability: The Value of Virtual Power, Volume II: Technical Appendix*.

framework dictates whether storage resources used as virtual power lines can also participate in the energy, ancillary service, and capacity markets to obtain further revenues. If located next to load centres, for example small-scale storage installed at consumers, they also improve consumers' experience with using the battery as back-up power during outages.

Figure 2: A virtual power plant



Thus, there are three types of aggregate storage and renewable generation systems, with three levels of interaction. These are compared in Table 1.

Table 1: Value streams of the three aggregate systems

Revenue stream	Co-located and operationally independent	Co-located and operationally integrated	VPP—not co-located but operationally integrated
Energy arbitrage	Low	Medium	High
Ancillary services	Low	Medium	High
Generation adequacy	Medium	Medium	High
Increased resilience	High	High	Medium

As Table 1 shows, in most cases VPPs can benefit the system to a greater extent than independently developed projects. Additional benefits include better financing terms for capital costs and lower operation and maintenance costs due to the operational link of the aggregate system that affects charge/discharge rates and in turn battery degradation. Moreover, in VPPs it is easier to add a greater number of complementary resources, since their link is virtual.

To assess the economic performance of any aggregate project, several metrics have been used. Levelized cost of energy and levelized cost of storage are probably the most widely used metrics. However, levelized cost of energy fails to quantify the additional benefits of the aggregate system (it ignores the cost of intermittency of renewables, whose balancing by including storage increases the cost of variable sources like wind and solar). A more suitable metric is the aggregate system's benefit/cost ratio, defined as dividing the annualized benefits (energy revenue and capacity value) by the annualized costs (capital and operating).[21] Other researchers have also used a net present value and real options analysis to assess the economic performance of aggregate systems.

Market and regulatory signals to promote coupling

The existing regional market and regulatory environment determine which level of interaction is best for each specific case. However, the environment should provide the same opportunity to all three levels of interaction without creating a bias—for example towards integrated or independent co-location, as is the case now (i.e., regulators often emphasize on physical co-location)—since VPPs can be more beneficial for the system in many cases, as explained in the previous sections.

The regulatory framework is very diverse worldwide, but in general tends to promote integrated co-location more than other levels of interaction. For example, the 30 per cent federal tax credit in the US may be applied to storage projects only when they are charged by a renewable generator. State-level renewable portfolio standards are also driving interest in PV and battery systems. The UK is supporting co-located aggregate systems with the so-called hybrid power purchase agreements (PPAs). For

[21] Denholm, P., Eichman, J., and Margolis, R. (2017), *Evaluating the Technical and Economic Performance of PV Plus Storage Power Plants*, National Renewable Energy Laboratory.

example, in June 2023 a 10-year hybrid PPA that includes a renewable PPA and a storage capacity agreement was signed for the co-located aggregate 55 MW PV and 40 MW battery system in Bedfordshire. In this hybrid PPA these two assets operate independently and have separate contractual agreements, merely sharing the technical and financial benefits of siting at the same location. Other hybrid PPA options include more linked operation. In 2023, the European Commission supported integrated co-location of storage and renewable generation projects under the condition that 75 per cent of the storage's energy comes from the renewable asset.[22]

However, there are some financial incentives that can also be used by VPPs. For example, in the UK from 1 February 2024, electrical storage batteries installed in residential buildings qualify for a zero value added tax rate.[23] This tax relief when first introduced in 2022 had only targeted physically co-located aggregate battery and PV installations. An important element for lift-off of VPPs is to allow them to participate in energy wholesale, ancillary services, and capacity markets as a single entity even though they might be located at different places. In 2020, US Federal Energy Regulatory Commission Order 2222 required all transmission system operators to allow VPP participation in wholesale markets. Its implementation is still ongoing; in 2023 two out of six operators allowed participation of VPPs as generators.[24] In October 2023, the UK Office of Gas and Electricity Markets allowed VPP participation in wholesale markets with Decision P415, Facilitating Access to Wholesale Markets for Flexibility Dispatched by Virtual Lead Parties; this will take effect in November 2024.

As an alternative to bidding into wholesale markets, VPP companies can also make bilateral arrangements with utilities, or a VPP may be operated by the utility itself; these are usually referred to as retail VPPs. VPP integration to grid planning is necessary to value their benefits appropriately and to promote investment in programmes and grid upgrades that enable VPPs. Further regulatory changes in terms of aggregators' participation in markets, mandates to implement smart grid infrastructure, and development of local markets at the distribution levels will enable VPPs and increase their revenue streams.

The main market signals that drive the viability of aggregated projects include electricity prices and tariff structure. A recent study showed that co-located projects in Alaska and California had comparable profits, even though the energy potential of e.g. PV resources is 3 kWh/m^2 in Alaska and 6 kWh/m^2 in California.[25] The reason for this lies in the average electricity price, which is $0.03/kWh in Alaska and $0.25/kWh in California. A further challenge that aggregate projects face is the zonal electricity prices that are found in most European countries, compared to the more favourable nodal electricity prices in the US.

Aggregate projects are favoured by any type of tariffs with demand charges and time-of-use characteristics. Tariff structures in general have an energy and demand component; these components are further categorized as fixed, tiered, and time of use. Note that there are tariffs that do not include a demand component. This is consistent across many regions, such as the US, Japan, Italy, Australia, and Germany, according to detailed studies.[11] Furthermore, aggregate projects can have access to different rates. For example, UK distribution networks apply the following pricing scheme: intermittent generators receive a set payment, and non-intermittent generators receive varying payments following a red, amber, and green charging structure (which corresponds to different payments in pence/kWh, with red the highest). Aggregate projects take advantage of the fact that storage resources are defined as non-intermittent and can be paid in the red payment band.[26]

Concluding remarks

This article presented the value of co-located aggregate and VPP projects. Its main takeaway is that the market and regulatory frameworks should not privilege a particular type of interaction, physical or virtual, and that if designed appropriately the frameworks suffice to give the appropriate investment and operation signals. For example, the main drawback of co-location of aggregate systems is that at least one technology will be sited suboptimally. However, there are cases where co-locating storage and renewable generation is effective, ensuring that excess renewable generation is not curtailed due to grid constraints, and thus it might be a more cost-effective solution than upgrading the network. In this case, if designed appropriately, the regulatory and market environment will provide the correct price signals to make investment in this co-located aggregate project profitable.

[22] Commission Regulation (EU) 2023/1315, Article 41.
[23] Energy-saving materials and heating equipment (VAT Notice 708/6).
[24] International Renewable Energy Agency (2019), *Aggregators, Innovation Landscape Brief*.
[25] McLaren, J. et al. (2019), 'Solar-plus-storage economics: what works where, and why?', *The Electricity Journal*, 32.
[26] Biggins, F. et al. (2023), 'The economic impact of location on a solar farm co-located with energy storage', *Energy*, 278.

To foster a level playing field among independent co-location, integrated co-location, and VPPs in electricity markets and regulatory frameworks, we need an approach that emphasizes technology-neutral participation, fair compensation, and regulatory flexibility. This includes ensuring that all configurations can participate equally in energy, capacity, and ancillary services markets, developing dynamic tariff structures that incentivize optimal operation of resources, and establishing uniform interconnection standards. Additionally, incentives should be designed to support overall system benefits rather than favouring specific configurations, while promoting innovation through support for pilot projects. Regulatory policies should also facilitate the integration of these configurations into grid planning, enhance data access for operational optimization, and encourage ongoing stakeholder engagement. These main points are also summarized in Table 2.

Table 2: Key conclusions regarding aggregate systems with different levels of interaction

Criteria	Co-located and operationally independent	Co-located and operationally integrated	VPP—not co-located but operationally integrated
Capital and operational costs	Lower initial costs, but potential for operational inefficiencies	Potentially lower due to shared infrastructure and efficiencies	Varies, with lower site-specific costs but higher costs for network management
Revenue streams	May miss out on some opportunities due to lack of operational coordination	Enhanced by leveraging combined capabilities for multiple services	Maximized through dynamic optimization across a broad network
Resource complementarity and reliability	Moderate, as resource complementarity is not fully leveraged	High, due to optimized pairing of generation and storage	High; leverages geographical diversity of resources
Grid support and flexibility	Limited, as operations are not coordinated to support grid needs optimally	Can provide substantial support through coordinated dispatch	Highly flexible, providing targeted services where needed most
Integration and management complexity	Lower, as each asset operates under simpler, independent control schemes	Moderate to high; requires sophisticated systems for optimal integration	High; requires advanced systems for managing distributed resources
Investment risk diversification	Like integrated co-location but with diversified operational risks	Concentrated at a single site; risk can be higher if not diversified	Highly diversified across multiple sites and technologies
Market participation and services	Focused separately on different market opportunities or services	Optimized for both energy markets and ancillary services	Adaptable to various market conditions and services, enhancing revenue potential
Regulatory and policy compliance	Dependent on specific regulatory structures favouring stand-alone operations	May benefit from incentives for integrated renewable and storage solutions	Must navigate diverse regulatory environments across locations
Technological and operational synergies	Reduced due to the lack of coordination between generation and storage	Maximized through the direct integration of storage and renewable operations	Depends on the efficiency of VPP management systems but generally high

DESIGNING ENERGY STORAGE DEPLOYMENT STRATEGIES — LESSONS FROM THE GREEK ELECTRICITY MARKET

Athanasios Dagoumas

The EU aims to be the first climate-neutral continent by 2050—an economy with net-zero greenhouse gas emissions. This constitutes a legally binding target, through the European Climate Law[27], and is a pillar of the European Green Deal.[28] EU member states develop national climate strategies for 2050 and National Energy and Climate Plans (NECPs) for 2030 on how they plan to achieve greenhouse gas emissions reductions.

Improvements in energy efficiency and inclusion of a high share of renewables in the energy mix, supplemented by energy storage, are considered clear, no-regret options for all EU countries. Although electricity storage is expected to lead to a significant increase in the penetration rate of renewables in electricity production, there is no single optimal solution on the design of energy storage deployment strategies.

This derives from the fact that different flexibility options are available in the electricity chain: consumption flexibility (demand response, vehicle-to-grid), production flexibility (Combined Cycle Gas Turbine [CCGT] and emergency units, hybrid units), and storage flexibility (batteries, pumping hydro, flywheels). Moreover, flexibility has four dimensions—time, space, technology, and risk profile[29]—and coordination between transmission system operators (TSOs) and distribution system operators (DSOs) along those four dimensions improves the usage of flexibility. Countries aiming to tackle flexibility needs implement their NECP, using mathematical models simulating long-term energy planning, integrating also aspects of the power system operation. TSOs might identify the need for developing storage assets as 'fully integrated network components' towards providing flexibility to the grid, but also increasing their regulatory asset base.

In the case of Greece, the relevant ministry identified in its NECP, firstly, the need to install storage technologies to support its ambitious renewable energy resources (RES) targets for 2030, and secondly, the need to design support schemes to facilitate those investments. A TSO request to develop storage assets as network components has not been adopted, as it would require derogation from European regulation, although there was high interest from market participants in such investments. Considering that the power system evolves dynamically, the electricity market provides price signals, which might not be clear and robust at the time of NECP simulations, which identified the need for support schemes. It is important to clarify that the state, supported by the regulator and the TSO, follows a top-down approach when designing long-term strategies for the energy or power system, aiming to maximize social welfare. However, investments are made by individual investors, who might identify an investment possibility on a market basis, without regard to any support scheme.

This article describes the design of energy storage deployment strategies for the Greek electricity market, from the state's top-down perspective. The policy intervention is an intermediate step towards facilitating the uptake of storage assets into the electricity grid, aiming at their penetration on a market basis in the medium to long term. The three main elements of the policy intervention in Greece are the following:

1. facilitating the licensing process to enhance competition.
2. state aid schemes to support investments and their operation as an intermediate step.
3. network expansion and clear price signals for the market uptake of flexible assets.

Facilitating the licensing process to enhance competition

The latest NECP for Greece aims, by 2030, to achieve more than 80 per cent penetration of RES in the electricity mix, 23.5 GW of RES assets, and 5.3 GW of storage assets (3.1 GW batteries and 2.2 GW pumping hydro). Considering that the peak demand is about 10 GW, RES and storage assets are supplemented by ambitious network interconnections, aiming to transform Greece into an exporter of green energy.

[27] Regulation (EU) 2021/1119 of the European Parliament and of the Council of 30 June 2021 establishing the framework for achieving climate neutrality and amending Regulations (EC) No 401/2009 and (EU) 2018/1999, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32021R1119

[28] https://commission.europa.eu/strategy-and-policy/priorities-2019-2024/european-green-deal_en .

[29] Kara G., Tomasgard A., and Farahmand H. (2022), 'Characterizing flexibility in power markets and systems', *Utilities Policy*, 75, 101349, https://www.sciencedirect.com/science/article/pii/S0957178722000145.

The implementation of RES or storage assets requires different levels of licenses,[30] of which the most important are the production license issued from the Regulatory Authority for Energy, Waste and Water (RAAEY), the environmental license, and the binding mandatory connection terms from the network operators. An innovative IT platform has been developed by the regulator to facilitate the licensing process, following relevant legal provisions. This has led to the issuing of production licenses for about 100 GW of RES assets, 45 GW of electricity storage assets (including hydro pumping), and almost 10 GW of RES-with-storage assets. This facilitation enhances competition, as the assets that have acquired production licenses hasten to mature their projects—i.e. make them eligible for participation in state aid auctions and to get financed—by obtaining the other required licenses (the environmental license, which might be delayed due to local opposition, and the binding network connections terms).

State aid schemes to support storage investments and their operation as intermediate step

Over the last years, Directorate-General for Competition (DG COMP) has approved four schemes for supporting electricity storage assets in Greece:

- Case SA.64736: investment grants and operating aid for the creation of electricity storage facilities connected to the high-voltage network[31]
- Case SA.57473: a pumped hydro plant in Amfilochia with 730 MW production and 680 MW storage capacity[32]
- Case SA.58482: remuneration for hybrid power stations in non-interconnected islands with 264 MW capacity until 2026[33]
- Case SA.56665: development of low-cost, environmentally friendly lithium-ion battery technology (designated by the EU as an Important Project of Common European Interest).[34]

The first two schemes in this list are partially funded by the Recovery and Resilience Facility, an instrument that provides grants and loans to support reforms and investments in the EU Member States. In these schemes, there exist also locational aspects: case 1 concerns three auctions, where the latter concerns areas where lignite plants are phasing out; case 2 concerns a pumping hydro investment in a specific location; and case 3 concerns investments in non-interconnected islands. The first list item is the main state aid scheme and is discussed in more detail below.

With an official decree, special terms and conditions for the conduct of the auctions were determined, identifying three auctions with single-step bidding of 400 MW, 300 MW, and 300 MW, for a total of 1,000 MW capacity, organized by the regulator. The first two auctions have been held and are reported on below.

The first auction invited bids for government support of facilities totalling 400 MW capacity, for batteries of at least 2 hours storage capacity, with investment support of €200,000/MW and operating support of up to €115,000/MW/year. To ensure conditions of healthy competition, the following rules for the auction for operating support were established:

- The minimum competition rate was set at 100 per cent, namely double capacity was required.
- The maximum power award limit per participant, cumulatively for the first two auctions, was 100 MW.
- Each participant was limited to bidding on a maximum of 25 per cent of the auctioned power (e.g. 100 MW in a 400 MW auction).

Participants were ranked based on the lowest bid cost (€/MW/year) and accepted in ascending order of bid costs until the exact amount of auctioned power was exhausted. Additional rules governing ranking were as follows:

- If two bids had the same price, the asset with the lowest maximum injection power (in MW) was ranked first.
- The last project was selected so that the total selected capacity did not exceed the amount of auctioned power by 5 per cent.

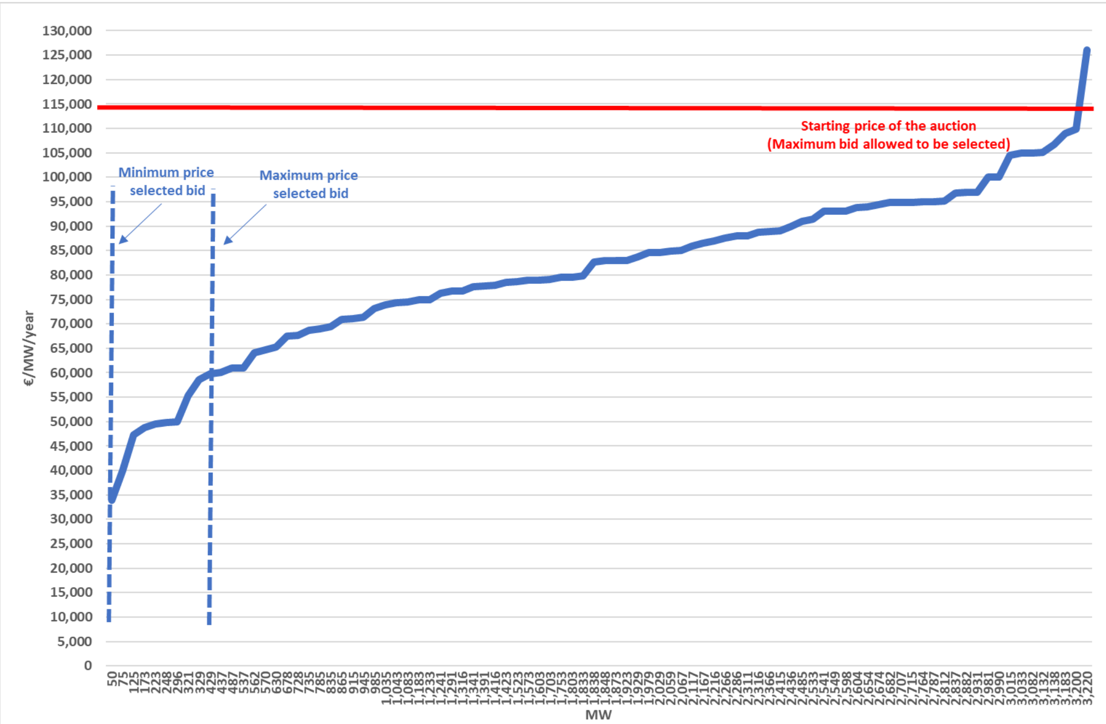
[30] https://www.rae.gr/ilektrismos/apothikeysi-ilektrismou/; https://www.rae.gr/ape/thesmiko-plaisio-ape-2/.
[31] https://competition-cases.ec.europa.eu/cases/SA.64736.
[32] https://competition-cases.ec.europa.eu/cases/SA.57473.
[33] https://competition-cases.ec.europa.eu/cases/SA.58482.
[34] https://competition-cases.ec.europa.eu/cases/SA.56665.

- If two or more bids were equal in both price and maximum injection power, and their selection would exceed the exact auctioned power, then the participants would be invited by the regulator to submit updated and improved financial offers, after which the asset with the lowest price would be selected.
- In the event that equal financial offers were submitted again, then the assets would be ranked based on their licensing maturity.
- In the event that the assets were also at the same level of licensing maturity, the participants would be excluded from the auction.

Auction results are shown in Figure 1. In summary, 93 projects with a total capacity of 3,299.55 GW participated, bidding on 8.25 times more than the auctioned capacity (400 MW). A total of 12 projects with a capacity of 411.79 MW were selected (the 'last project' rule applied as described above). Regarding prices:

- The lowest price selected was €33,948/MW/year.
- The highest price selected was €64,112/MW/year.
- The weighted average price was €49,748/MW/year.
- The weighted average price was 56.74 per cent lower than the starting price of the auction, which was €115,000/MW/year.

Figure 1: Supply-demand curve of the first auction for financial operating support of electricity storage in Greece



Source: Regulatory Authority for Energy, Waste and Water, https://www.rae.gr/wp-content/uploads/2023/08/%CE%9563%CE%A8%CE%99%CE%94%CE%9E-%CE%9C7%CE%A7.pdf

The selected projects must be implemented by 2025 and their renumeration, concerning the operating aid, is done through a procedure that considers an ex-ante estimation of the initial required aid and an ex-post settlement of the required aid.

The ex-ante operating aid (ExAOA) estimation in year y, expressed in euros per MW, calculated separately per storage asset i ($ExAOA_{i,y}$), is the difference of the reference revenue of the specific project (RR_i) from the estimated purchase revenue of the project group to which it belongs ($EMR_{j,y}$), i.e. projects of the first two auctions with 2-hour batteries, taking into account any adjustments that arise due to estimated additional income ($EAR_{i,y}$) and estimated loss of income ($ERL_{i,y}$), as follows:

$$ExAOA_{i,y} = RR_i - EMR_{j,y} - EAR_{i,y} + ERL_{i,y}$$

EAR concerns any investment, operational, or other type of support outside of the support scheme under which the assets has been awarded, while ERL concerns the reduction of net market revenues due to the mandated provision of additional services without renumeration.

The ex-post operating aid (ExPOA) calculation is as follows:

$$ExPOA_{i,y} = -p_{mr,i,y}(AMR_{j,y} - EMR_{j,y}) - (AAR_{i,y} - EAR_{i,y}) + (ARL_{i,y} - ERL_{i,y})$$

where AMR, AAR, and ARL concern the actual revenues, compared to EMR, EAR and ERL, respectively.

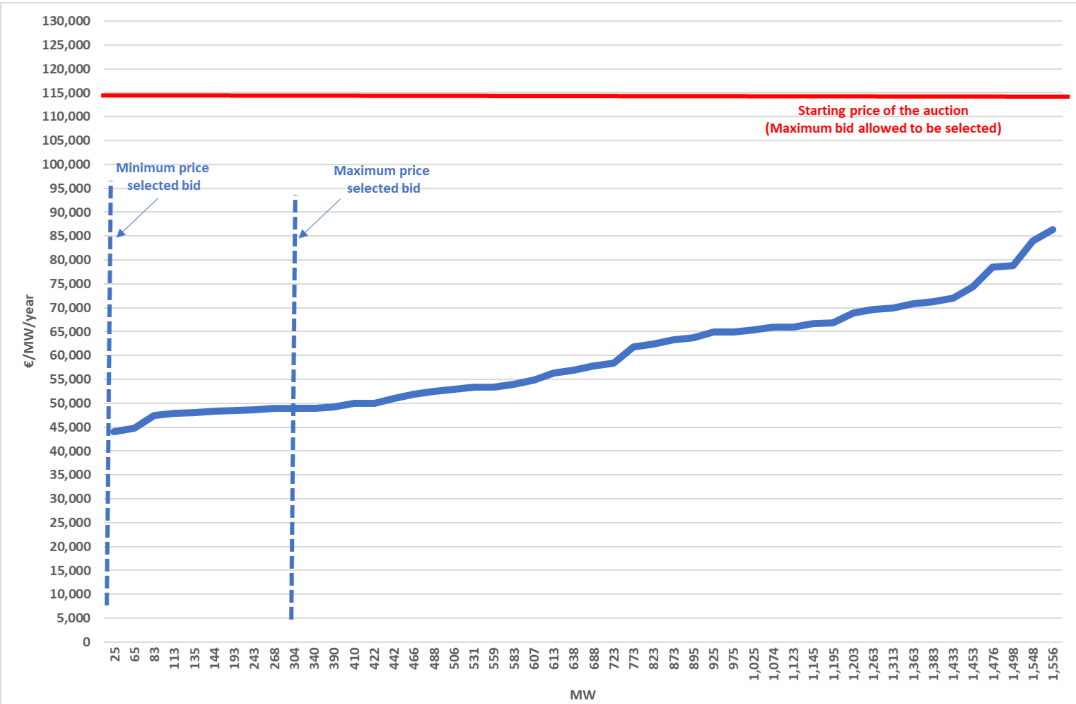
This methodology enables the avoidance of overcompensation, in case of multiple revenues, as well the consideration of unpaid services. Moreover, it enables extra compensation for assets that perform better (more competitively) than similar units within the same group. The methodology also enables relevant minor modifications of the initially expected revenues, which creates uncertainty but also expectations for potential higher renumeration.

The second auction invited bids on 288 MW (the planned 300 MW minus the additional 12 MW allocated in the first auction), for batteries of at least 2 hours storage capacity, with investment support of €100,000/MW, reduced due to high competition in the first auction, and operating support up to €115,000/MW/year.

Auction results are showed in Figure 2. In summary, 48 projects with a total capacity of 1,555.76 GW participated, bidding on 5.4 times the auctioned capacity (288 MW). A total of 11 projects with a capacity of 299.78 MW were selected (again, the 'last project' rule applied). Regarding prices:

- The lowest price selected was €44,100/MW/year.
- The highest price selected was €49,917/MW/year.
- The weighted average price was €47,680.36/MW/year.
- The weighted average price was 58.54 per cent lower than the starting price of the auction, which was €115,000/MW/year.

Figure 2: Supply-demand curve of the second auction for financial operating support of electricity storage in Greece



Source: Regulatory Authority for Energy, Waste and Water., https://www.rae.gr/genika-nea/80093/

Participation in the second auction, while still high, was lower than in the first auction, possibly explained by the exclusion of selected projects in the first auction, and the exploration of different schemes for implementing the projects (bilateral power purchase agreements). The weighted average price of the selected projects was also slightly lower than in the first auction.

The terms for the third auction are set to be published soon. For the time being they concern the support of 300 MW for batteries of at least 4 hours storage capacity, installed in ‘regions of just transition’, namely regions where lignite assets are phasing out.

Network expansion and clear price signals for the uptake of flexible assets

Under the European regulation, TSOs and DSOs shall not own, develop, manage, or operate energy storage facilities. In Greece, the TSO has requested development of fully integrated network components, including integration of storage facilities within the transmission system, used for the sole purpose of ensuring secure and reliable operation of the system and not for balancing or congestion management. However, for the time being, this has not been approved,[35] and derogation has not been requested.

Therefore, penetration of storage assets is open to market participants, implemented either through support schemes, as described above, or investments with or without RES to participate in the wholesale market and/or form bilateral power purchase agreements.

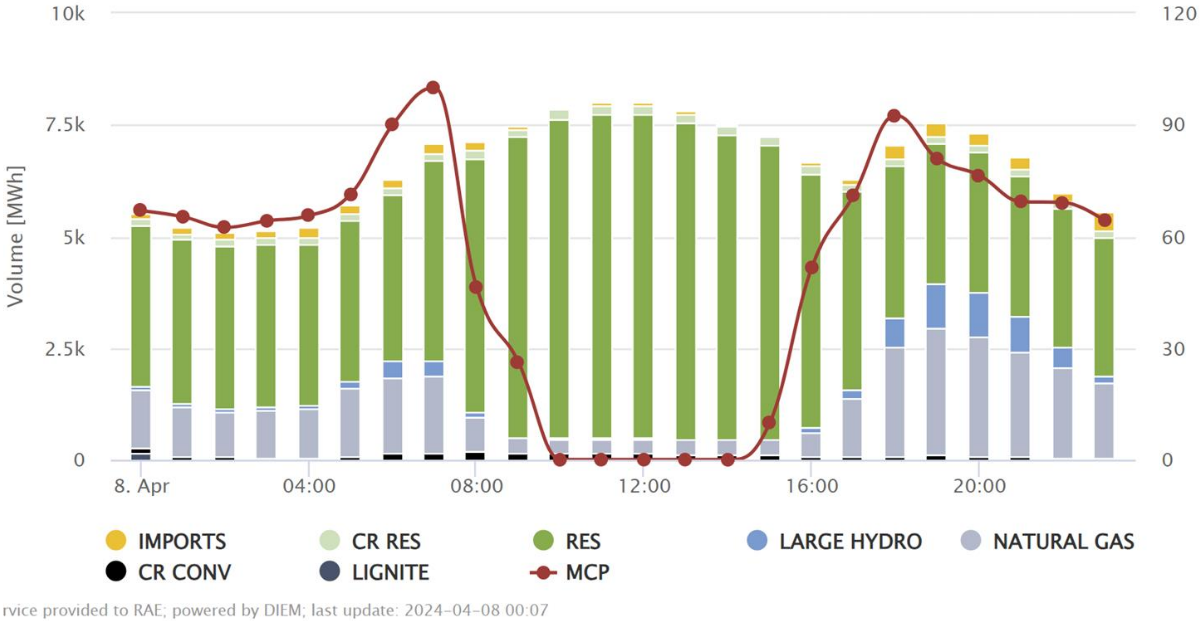
However, as mentioned above, the ambitious targets for RES and storage cannot be reached without enhancing networks. Therefore, the TSO is implementing an ambitious 10-year network development plan,[36] approved by the regulator, of about €5 billion, aiming at interconnecting all islands to the mainland system by 2030, as well as increasing interconnection capacity with neighbouring systems (Bulgaria, Italy, Turkey, North Macedonia, Albania, and Cyprus), while interconnections with Egypt, Saudi Arabia, and Slovenia/Austria/Germany are explored. This plan aims to transform Greece from a net electricity importing country, as it has been over the last decades, to a net electricity exporting country, specifically of green energy.

Although the approved network development plan will lead to about 28 GW electric space for RES assets, over-fulfilling the targets of NECP according to the TSO estimations, the issuing of binding connection terms and curtailment of RES electroproductions stand as major issues for the Greek system, as well as for other power systems with high-RES penetration. Storage assets support RES penetration; therefore, the Hellenic Ministry for Environment and Energy is exploring the possibility of requiring new RES installations to be accompanied by storage assets, in order to support RES penetration and eliminate curtailments and potential renumeration requests from investors. However the main driver is the fact that wholesale market provides clear price signals for the uptake of flexible assets, such as demand response and storage assets, without any support scheme, as can be shown in Figure 3. The price differences, due to the photovoltaics penetration, create clear signals for load shedding and investments in flexible assets and facilitate the electrification of new sectors such as transportation.

Finally, after many years of juridical delays, the implementation of smart meters by the DSO will take place. This will enable the engagement of final consumers at all voltage levels, and the active participation of demand response. Moreover, electric vehicles and plug-in hybrid vehicles are becoming the dominant options in the new fleet, while providers are expanding their charging stations and therefore enabling vehicle-to-grid power flow. Network development has been enhanced by a recent regulatory decision on network tariffs, moving from 80 per cent-20 per cent energy-capacity based to 10 per cent-90 per cent capacity based. The engagement of the consumer, through demand response and/or active participation through RES/storage/electric vehicle assets, supplemented by the development of a TSO-DSO coordination platform, is expected to facilitate the market penetration of storage assets.

[35] https://www.iene.eu/articlefiles/inline/dagoumas%2028%2009%202022.pdf.
[36] https://www.admie.gr/en/grid/development/ten-year-development-plan.

Figure 3: Typical energy mix and price evolution in the Day-Ahead electricity Market in Greece



Source: Regulatory Authority for Energy, Waste and Water, https://www.rae.gr/en/market-monitoring/greek-wholesale-electricity-markets/electricity-prices-statistics/energy-mix/

Summary

Inclusion of renewables in the power mix, supplemented by electricity storage, is considered a no-regret step towards meeting ambitious climate targets for any EU country. However, there is no optimal solution in the design of energy storage deployment strategies. This derives from the fact that different flexibility options are available in the electricity chain: consumption flexibility (demand response, vehicle-to-grid), production flexibility (CCGT and emergency units, hybrid units) and storage flexibility (batteries, pumping hydro, flywheels). Considering the energy transition commitments and the time required for the market uptake of flexible assets, the state can support energy storage deployment.

This article describes the design of energy storage deployment strategies for the Greek electricity market, from the state's top-down perspective. The strategy consists of the following three main elements:

1. facilitating licensing process to enhance competition.
2. state aid schemes to support investments and their operation as an intermediate step.
3. network expansion and clear price signals for the market uptake of flexible assets.

Concerning the first, an innovative IT platform has been developed by the regulator that has facilitated the licensing process, enhancing competition. Concerning the second, Directorate-General for Competition (DG COMP) has approved four schemes for supporting electricity storage assets in Greece, including funds from the Recovery and Resilience Facility. Granting investment and operating support includes the implementation by the regulator of auctions, where the facilitation of licences has already led to increased competition and to reduction in the prices of the selected bids.

Concerning the third, ambitious targets for RES and storage cannot be achieved without enhancing networks. The TSO is implementing an ambitious 10-year network development plan, aiming to transforming Greece to a net electricity exporting country, specifically of green energy. However, the issuing of binding connection terms and curtailment of RES electricity production are major issues for the Greek system, as well as other power systems with high-RES penetration. The role of storage is crucial in offsetting that effect. The engagement of the consumer, through demand response and/or active participation through RES/storage/electric vehicle assets, supplemented by the development of a TSO-DSO coordination platform, is expected to facilitate the market penetration of storage assets.

The policy intervention from the Hellenic State is an intermediate step towards facilitating the uptake of storage assets into the electricity grid, aiming at their market penetration in the medium to long term. It seems to be effective, as it supports the energy transition targets, while competition for storage assets leads to reduction in the required support scheme. Moreover, locational aspects are also considered, as storage assets' needs are identified for specific areas (locations where lignite plants are phasing out, with hydro pumping storage, or in non-interconnected islands). No further support scheme is expected to be needed, as market uptake of storage and other flexible assets is driven by clear wholesale price signals. As mentioned above, there is no one optimum solution in the design of energy storage deployment strategies; however, elements of the Greek policy intervention could be considered for adoption by other states as an intermediate step to support energy transition and the market uptake of flexible assets.

MARKET REFORM CONSIDERATIONS FOR BULK ENERGY STORAGE

Jacob Mays

The analysis of electricity markets has long relied on a critical characteristic of electricity that sets it apart from other commodities: non-storability. Outside of regions with significant reservoir hydropower, non-storability has become a core feature of the conceptual model used to understand the pricing of electricity. In the classic merit order curve, generators are arranged according to fuel cost, with the spot price in a period determined by the intersection of this curve with a largely fixed demand. This mental picture does not have a natural place for the bids and offers of storage resources, which can change based on frequently updated estimates of opportunity costs as forecasts for uncertain demand, supply, and transmission availability evolve over the course of a day.

The need for an update to this conceptual model is more apparent by the day. At the end of 2022, US interconnection queues held approximately 680 GW of storage, primarily in the form of short-duration batteries.[37] In addition to these dedicated resources, many states anticipate significant growth in electric vehicles, the collective storage capacity of which could exceed that provided by stationary systems. Further ability to shift load could be found by taking advantage of thermal storage in buildings and hot water heating systems. Efforts to understand the implications of various types of storage have motivated advances in many of the models used for planning and operating power systems. Re-examining the assumptions used in software for capacity expansion, resource adequacy, production cost, interconnection, market clearing, and more, researchers and practitioners have found existing tools wanting.

The purpose of this article is to outline market design questions raised by the entry of significant quantities of storage, focused on the organized wholesale markets of the US. In principle, a goal of wholesale electricity market design is to facilitate deployment of any technology capable of providing the services expected from storage without predetermining the technology that will provide those services. Hoping to remove potential barriers to storage embedded in market design, the Federal Energy Regulatory Commission issued Order 841 in 2018. Despite the progress that has been made since that time, many questions remain regarding participation models for storage. Developers of long-duration storage in particular often cite market and regulatory barriers to deployment as key factors preventing technology maturation.

The first set of challenges relates to valuing the services provided by storage in markets for energy, ancillary services, and resource adequacy. A second set of challenges concerns how to facilitate contracting around those value streams. The article closes with some consideration of the modelling improvements needed to address the questions raised.

Valuing storage

Since the inception of liberalized electricity markets, market designers and regulators have struggled to ensure formation of spot prices conveying the full value that resources bring to the power system. Relative to traditional generation technologies, inefficiencies in price formation are likely to be particularly important for storage. Under idealized assumptions, volatility in prices is sufficient to support efficient operation of and investment in storage. In practice, systems suppress real-time price volatility through various mechanisms, leading to the question of whether storage will be adequately incentivized.

[37] Rand, J., Strauss, R., Gorman, W., Seel, J., Kemp, J. M., Jeong, S., Robson, D., and Wiser, R. H. (2023), *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection*, Berkeley, CA: Lawrence Berkeley National Laboratory, https://emp.lbl.gov/queues.

Given the significant volatility already present in wholesale electricity prices, it is surprising to some that theory suggests they should be even more volatile. Suppression of volatility takes various forms. In terms of locational volatility, outside the US many wholesale markets produce spot prices at a zonal level. Since storage may be easier to site than many generation technologies, zonal pricing could be particularly disadvantageous in obscuring the value that could potentially be provided by storage. In the US, the same argument applies below the wholesale level. In terms of temporal volatility, the mechanisms of interest include capacity markets, active power ancillary service products, reliability unit commitment processes, and enhanced price formation methods. At a high level, the relationship of each of these mechanisms with reduced volatility is well understood, but their concrete impacts are poorly quantified.

Just as price suppression can lead to a ‘missing money’ problem necessitating the introduction of supplemental revenue streams to ensure enough capacity, suppression of price volatility implies a need for interventions to restore efficient incentives for flexibility. In this context, a key question is whether the theoretical value that would otherwise be conveyed through price volatility is adequately approximated by the ‘second-best’ strategies that have been adopted by market operators to encourage flexibility. For example, to date many batteries operating in US markets have derived a significant portion of their total revenue through provision of reserves. Defining active power reserve products has the effect of reducing energy price volatility. Under normal conditions, reserving capacity for future use removes supply from the dispatch, leading to higher prices; in challenging conditions, reserves are released for dispatch, leading to lower prices than might have otherwise occurred. In storage terms, instead of conveying the value of energy arbitrage through energy prices, the market operator conveys it through the definition of the reserve products.

In addition to affecting prices, market operators can also affect the quantities of products sold by storage resources, most importantly in the context of capacity markets. The proximate cause for limiting capacity offers from storage is their energy-limited nature: a 4-hour battery, for example, could deplete its charge before the end of a longer scarcity event. The more fundamental reason an accreditation process is needed, however, is that penalties for nonperformance on capacity obligations are typically lower than recommended by economic theory, giving suppliers an incentive to overstate their ability to deliver on them. A consequence of this process is to introduce a significant administrative component in the quantities that resources are able to sell. While this administrative component applies to all resources, the uncertainty induced by it may be most significant for storage, due to evolution in the methods used to evaluate its contribution to reliability.

For efficient operation and investment in storage, the core concern is how well the product, price formation, and quantity decisions made by market designers convey the fundamental value of the energy arbitrage being performed. Even as storage thrives on volatility, market operators and regulators have good reason to avoid it. In a world without the textbook ideals of perfect competition and complete markets in risk, it is easy to understand why many other market participants would prefer to prevent volatility from arising. The question is whether doing so may undermine the ability of the markets to facilitate deployment of the best solutions to that volatility in the long term.

Contracting storage

A second long-standing challenge for market designers and regulators has been establishing conditions under which efficient long-term contracting among market participants can take place. In this context, it is worth considering the design of contracts supporting the deployment of storage. As with solar and wind, large-scale deployment of storage in the US has been initially spurred by state-supported contracts. While such procurement is likely to continue in some form in many states, in others it is anticipated that contracting will be increasingly driven by market participants. As described above, the first step in setting the conditions for efficient long-term contracting is establishing price formation policies that reflect the underlying value of the resource. In theory, this first step could be considered sufficient, and market participants could fashion long-term contracts according to their risk exposures and risk attitudes. In practice, electricity market operators and regulators have played a strong role in mandating certain types of contracts and conditioning the residual risk around which market participants design contracts.

Three features of existing markets are likely to have material effects on the near-term efficiency of storage contracting. The first issue relates to the discussion of reserve product design above. In principle, since the overall effect of reserve products is to strip volatility out of energy prices and to package it as a product, ancillary services can be thought of as an implicit short-term risk trade: storage and other suppliers exchange the arbitrage opportunities presented by price volatility for more predictable revenues from the reserve product. However, with the design of reserve products in constant flux, this configuration may be disadvantageous in terms of long-term contracting. Financing based on revenues from ancillary services rather than energy is not yet standard and opens the possibility of regulatory risk due to changes in the definition of reserve products or in eligibility to provide them.

The second issue relates to the form of resource adequacy constructs currently used in US markets, which financially resemble a strip of call options covering each interval in the specified delivery period (e.g. one year). Such a contract is appropriate for a thermal resource that can credibly commit to physically backing it without energy limitations. A better financial analogue for storage may be a strip of swing options, under which system operators would have the right to call on the resource a certain number of times in each subperiod tied to the duration of the resource (e.g., 4 hours per day for a typical battery). The question is whether, by mandating contracts of a particular form that is well suited to thermal resources, current capacity mechanisms could crowd out the more efficient contracting that might be expected with greater diversity in resource types.

The third issue is ensuring that contracts, whether initiated by governments or implied through resource adequacy mechanisms, preserve incentives for efficient storage operations in the short term.[38]

Modelling storage

Given the market design questions outlined above, it is worth considering what is needed to move beyond the simplified conceptual model of the merit order curve. From a modelling perspective, the fundamental issue is overreliance on static models that prevent an accurate appraisal of the value of storage. In a static merit order curve, the clearing price of electricity can be described by the fuel cost of the marginal plant on the system. In a dynamic modelling framework, marginal cost includes not only the direct cost incurred in the present period, but also the change in expected cost that will be incurred in future periods based on the state of the system resulting from current actions. Entering the next period with less energy remaining in storage, for example, comes with a cost if it makes us more likely to engage expensive backup resources. Accurately accounting for these opportunity costs entails advances in scenario generation and simulation. To the extent these effects are not captured in simplified models, errors will occur in the resulting prices. With rapid growth in storage over the coming years, the errors introduced by simplified models of price formation are likely to become even more significant.

In recent years, market operators across the US and worldwide have been implementing reforms to spot markets, introducing new storage participation models, reserve products, and price formation policies with the stated aim of better reflecting the effects of uncertainty, variability, nonconvexity, and intertemporal constraints. The range of solutions pursued across different markets raises questions about their relative efficiency and the long-run implications of alternative specifications. In a recent example, an analysis performed by the Independent Market Monitor of the Electric Reliability Council of Texas (ERCOT) estimated that a new Contingency Reserve Service introduced in summer 2023 had increased charges by $12.5 billion over approximately six months,[39] a number disputed by ERCOT. Neither ERCOT nor the Independent Market Monitor appear to have simulation tools capable of assessing the costs and benefits of the new product in a sound way, leaving regulators in the dark as to its costs and benefits. Given the significant implications that market design reforms can have for the cost, reliability, and environmental performance of electricity systems, there is a clear need to invest in such tools. While the modelling and computational challenges are not insignificant, such an effort would be likely to bring value well in excess of its costs.

PRICE FORMATION AND LONG-TERM EQUILIBRIUM IN FUTURE ELECTRICITY MARKETS: THE ROLE OF ENERGY STORAGE

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The electric power system is at the centre of decarbonization efforts in many parts of the world, leading to a shift towards zero-carbon generation resources while electrifying other energy sectors such as heating and transportation. Multiple technologies can provide zero-carbon electricity. However, with the rapid decline in the costs of wind, solar, and batteries, it is likely that these resources will make up a large part of future electricity supply. The characteristics of variable renewable energy (VRE) and energy storage (ES) are different from the generation resources typically prevalent in existing systems. The available generation from VRE is weather-driven and therefore variable and uncertain. Moreover, operating costs are very low, and may even be zero or negative due to incentive schemes. At the same time, ES brings additional intertemporal dynamics into the electricity markets, where operational decisions for charging and discharging are driven by the expected future value of stored energy through so-called opportunity costs.

As existing generation resources retire, VRE and ES will have an increasingly important impact on the price dynamics in future

[38] Billimoria, F., and Simshauser, P. (2023), *Contract Design for Storage in Hybrid Electricity Markets*, https://doi.org/10.17863/CAM.99024.
[39] Potomac Economics (2023), *Independent Market Monitor (IMM) Report*, https://www.ercot.com/files/docs/2023/12/11/13%20Independent%20Market%20Monitor%20(IMM)%20Report.pdf.

electricity markets. A key question is therefore whether the expected future dominance of VRE and ES requires a complete rethink of electricity markets or if marginal improvements to existing market designs are sufficient.[40] Arising issues such as increasing VRE curtailments, lack of incentives for ensuring sufficient flexibility and reliability, the need for new instruments for long-term contracts, and the role of markets vs central planning are widely discussed and analysed.[41]

In this paper, we use a stylized analytical model to illustrate price formation, revenue sufficiency, and long-term market equilibrium as we transition towards zero-carbon electricity systems dominated by VRE, with a particular focus on the role of ES. By investigating the extent to which marginal-cost pricing can provide incentives for investments and reliability as the resource mix changes, these results provide some fundamental and quantitative insights into challenging questions about future electricity market design.

Price formation and long-term equilibrium: from thermal to renewables and storage

We apply a simple load-duration-curve approach to investigate price formation and long-term equilibrium in the electricity market,[42] factoring in the effect of VRE and ES in investments, dispatch decisions, and resulting prices.

We employ a set of simplifying assumptions to be able to derive analytical insights. First, VRE capacity is a decision variable, just like the capacity of conventional generation. The VRE power output is modelled as a negative load—that is, a deterministic time series of VRE availability is multiplied by the installed capacity and subtracted from the hourly loads. A net load duration curve is derived, accordingly, as part of the optimization, an approach taken by several authors.[43] Our approach ignores operational constraints such as the need for inertia to maintain reliability, while also omitting the inter-temporal and uncertain nature of VRE availability.

We find market equilibrium solutions by assuming perfect competition between market participants, full downward dispatchability of VRE generators, no transmission bottlenecks, and prices set to the value of lost load (VOLL) during scarcity conditions. In addition, we assume an idealistic representation of ES,[44] where ES is capable of perfectly shifting energy from surplus to scarcity hours over the course of the year, with charge and discharge only constrained by how much ES power capacity is installed. It follows from this representation that it is only the power capacity of ES that is considered as an investment variable, without explicitly accounting for energy capacity constraints. Charging and discharging efficiencies are assumed constant.

These assumptions are obviously simplistic but enable us to derive analytical expression for the optimal capacity expansion, dispatch, and prices directly from the system cost minimization problem. Based on the market clearing prices that follow from the least-cost expansion model, we are able to solve corresponding profit maximization investment problems for each of the considered technologies. Under a price taker assumption, we analyse to what extent profit-maximizing investors in these technologies would arrive at the same expansion and operational decisions as in the least-cost model. This is the case in a system with only conventional thermal generators.[45]

[40] Newbery, D., Pollitt, M.G., Ritz, R.A., and Strielkowski, W. (2018), 'Market design for a high-renewables European electricity system', *Renewable and Sustainable Energy Reviews*, 91, 695–707, https://doi.org/10.1016/j.rser.2018.04.025; Gerres, T., Chaves Ávila, J.P., Martín Martínez, F., Abbad M.R., Arín R.C., Sánchez Miralles, Á. (2019), 'Rethinking the electricity market design: remuneration mechanisms to reach high RES shares—results from a Spanish case study', *Energy Policy*, 129, 1320–1330, https://doi.org/10.1016/j.enpol.2019.03.034.

[41] See e.g. Joskow, P.L. (2019), 'Challenges for wholesale electricity markets with intermittent renewable generation at scale: the US experience', *Oxford Review of Economic Policy*, 35(2), 291–331, https://doi.org/10.1093/oxrep/grz001; Wolak, F.A. (2021), *Long-Term Resource Adequacy in Wholesale Electricity Markets with Significant Intermittent Renewables*, Working Paper 29033, National Bureau of Economic Research, https://doi.org/10.3386/w29033; Strbac, G., Papadaskalopoulos, D., Chrysanthopoulos, N., Estanqueiro, A., Algarvio, H., Lopes, F., de Vries, L., Morales-España, G., Sijm, J., Hernandez-Serna, R., Kiviluoma, J., and Helisto, N. (2021), 'Decarbonization of electricity systems in Europe: market design challenges', *IEEE Power and Energy Magazine*, 19(1), 53–63, https://doi.org/10.1109/MPE.2020.3033397; Gruenspecht, H. K., Pfeifenberger, H., Joskow, P.L., and Schmalensee, R. (2022), *Electricity Sector Policy Reforms to Support Efficient Decarbonization*, MIT Center for Energy and Environmental Policy Research Working Paper No. 2022–007, https://ceepr.mit.edu/wp-content/uploads/2022/04/2022-007.pdf; Zhou, Z., Botterud, A., and Levin, T. (2022), *Price Formation in Zero-Carbon Electricity Markets: The Role of Hydropower*, Technical Report ANL-22/31, Argonne National Laboratory, https://publications.anl.gov/anlpubs/2022/07/176317.pdf; Newbery, D.M. (2023), 'High renewable electricity penetration: marginal curtailment and market failure under "subsidy-free" entry', *Energy Economics*, 126, 107011, https://doi.org/10.1016/j.eneco.2023.107011.

[42] See e.g. Green, R. (2000), 'Competition in generation: the economic foundations', *Proceedings of the IEEE*, 88(2), 128–139. https://doi.org/10.1109/5.823994

[43] See e.g. Kennedy, S. (2005), 'Wind power planning: assessing long-term costs and benefits', *Energy Policy*, 33(13), 1661–1675. https://doi.org/10.1016/j.enpol.2004.02.004

[44] This approach is similar to that of Steffen, B., and Weber, C. (2013), 'Efficient storage capacity in power systems with thermal and renewable generation', *Energy Economics*, 36, 556–567, https://doi.org/10.1016/j.eneco.2012.11.007.

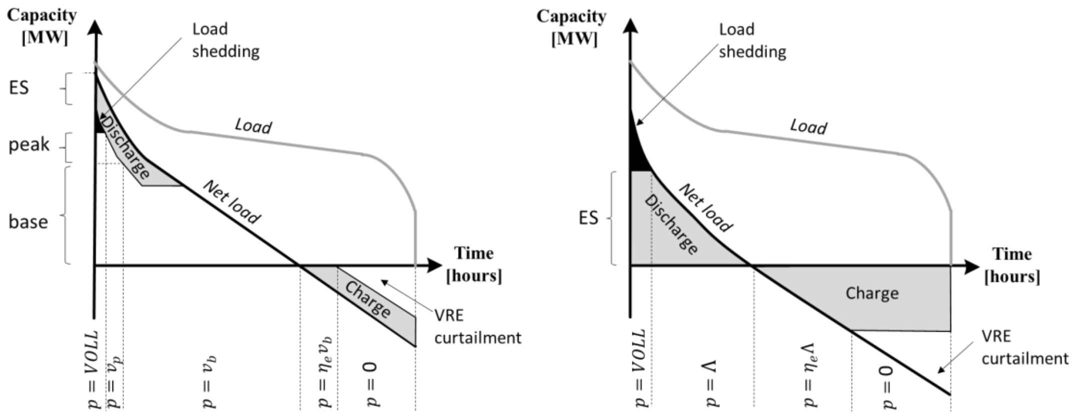
[45] See e.g. Green, R. (2000), 'Competition in generation: the economic foundations', *Proceedings of the IEEE*, 88(2), 128–139, https://doi.org/10.1109/5.823994. For a more comprehensive discussion of how to assess the benefits and value of energy storage in the grid, see Schmidt, O., and Staffell, I. (2023), *Monetizing Energy Storage: A Toolkit to Assess Future Cost and Value*, Oxford University Press, https://doi.org/10.1093/oso/9780192888174.001.0001.

To illustrate how technology mix, operations, and prices may evolve in the transition to a zero-carbon system, we constructed stylized models with four different scenarios, organized as a sequence from a traditional thermal to a fully decarbonized system. In scenario 1, only thermal generation technologies are available to meet the load; in scenario 2, VRE is added to the allowable generation mix. ES is added as an investment option on top of that in scenario 3. Finally, in scenario 4, thermal generation is no longer allowed, leading to a zero-carbon system based on VRE and ES only.

Analytical insights

The basic principles and results from our analytical approach, based on net load duration curves, are illustrated in Figure 1 for scenarios 3 and 4, which both include ES. The optimality conditions for the system cost minimization problem give us expressions for the amount of time different technologies remain on the margin (i.e., the durations on the x axes in the figure), as well as the corresponding prices (which are the marginal system costs—i.e., the dual value of the power balance). In turn, from the durations, the optimal capacity mix can easily be derived for all fully flexible resources (base, peak, ES) from the net load duration curves (i.e., along the y axes in the figure).

Figure 1: Net load duration curve approach used to solve the market equilibrium problem, with optimal expansion and dispatch results



Notes: Results are indicated for scenario 3 (base, peak, VRE, and ES) on the left and for scenario 4 (VRE and ES only) on the right. The y axes indicate optimal capacity for base and peak (scenario 3) and for ES (scenarios 3 and 4). Optimal VRE capacity is reflected in the net load duration curves. Prices (p) for different durations are indicated along the x axes, with VOLL = value of lost load, v_p = variable cost for peak plant, v_b = variable cost for base plant, η_e = round-trip efficiency of ES, and Λ = a functional expression which includes the capital costs for VRE and ES.

An important analytical result is that the amount of time when load exceeds supply remains the same as long as the thermal generators are part of the optimal mix. This is because the duration of load shedding is dictated by the assumed VOLL and the capital cost of the peaking plant. The amount of load shedding may still change as the shape of the net load duration curve changes depending on the optimal amount of VRE in the system. The equilibrium prices are all given by operational parameters when thermal generators are included (e.g., VOLL, marginal generation cost for base and peak plants, ES efficiency for scenario 3). The resulting prices make sure that all technologies, also including VRE and ES, when considered, exactly cover their total costs in scenarios 1 to 3.

The long-term equilibrium conditions change in scenario 4, which includes VRE and ES only. The first-order optimality conditions of the least-cost system planning problem now give dispatch durations that are functions of the capital costs of ES and VRE. Moreover, the resulting market clearing prices during ES charging and discharging also depend on capital costs, as illustrated in Figure 1 for scenario 4. Hence, the operational problem can no longer be separated from the planning problem. The resulting equilibrium prices still ensure cost recovery, but are a function of capital costs. Hence, it is questionable if such prices would emerge under current electricity market designs which rely on the assumption that generator offers are based on marginal operating costs only. VRE and ES would have to reflect their capital costs in offer prices in order to break even. This would raise questions around potential exercise of market power, as offers would deviate from short-run operating costs.[46]

[46] The insights outlined above emerge from the analytical model and do not depend on specific assumptions about technology costs. Full details of the mathematical formulations and equilibrium results are provided in Korpås, M., and Botterud, A. (2020), *Optimality Conditions and Cost Recovery in Electricity Markets with Variable Renewable Energy and Energy Storage*, MIT Center for Energy and Environmental Policy Working Paper 2020-005, http://ceepr.mit.edu/publications/working-papers/721; and Tarel, G., Korpås, M., and Botterud, A. (2024), 'Long-term equilibrium in electricity markets with renewables and energy storage only,' *Energy Systems*, https://doi.org/10.1007/s12667-024-00654-y.

Numerical example

Next, we provide some numerical results from the analytical net load duration curve model, based on the cost parameters described in Table 1. VOLL is set to a relatively low value of €3000/MWh and the round-trip efficiency for ES to 85 per cent. Note that for ES, the model only considers the capital cost for power capacity while any additional cost for energy capacity is ignored, since the latter is not treated explicitly in the model. The hourly load curve data is taken from the ENTSO-E 2040 Global Climate Actions scenario,[47] and the wind availability data used to represent VRE from the JRC EMHIRES data set.[48] The system peak is set to 100 GW for simplicity. Note that all parameters, although realistic by order of magnitude, are chosen so that all technologies are part of the optimal generation mix. In other words, we are interested in equilibrium situations with multiple technologies rather than situations in which a subset of technologies dominates the others.

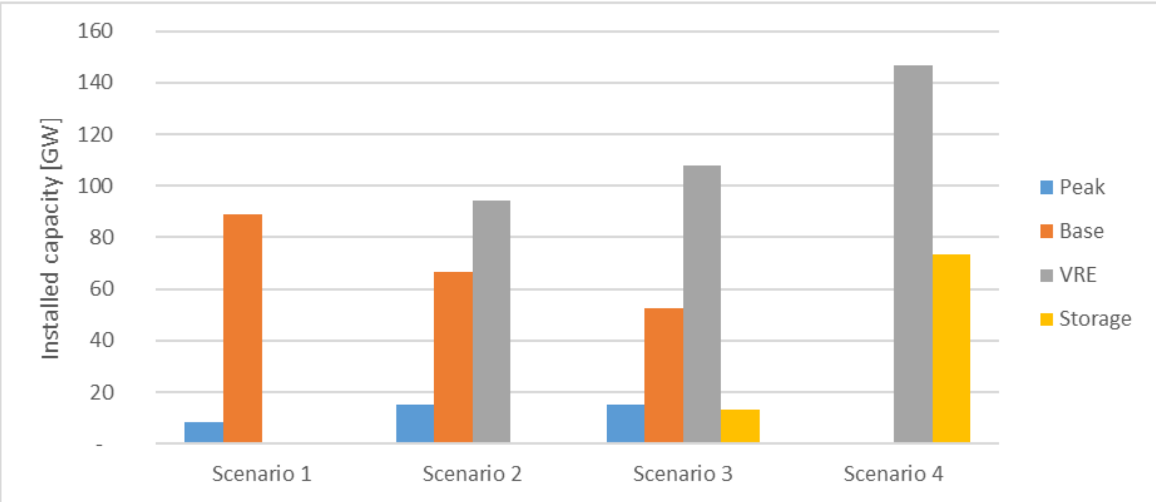
Table 1: Assumed costs for the different technologies

	Peak	Base	VRE	ES
Capital (€/kW)	320	640	1,890	2,380
Variable (€/MWh)	155	103	0	0

Note: Additional costs of maintenance and degradation are ignored for all technologies. The latter is of particular importance for ES.

In each scenario, we compute the equilibrium results based on the analytical model outlined above as well as for a conventional least-cost generation expansion model with the same constraints, and confirm that the results are identical. The computed equilibrium features both the minimum system cost and results in cost recovery for all considered technologies (including VRE and ES) across the four scenarios. The optimal expansion plans are given in Figure 2. Scenario 1 includes primarily base generation with a small amount of peaking capacity. When VRE is added in scenario 2, the amount of base capacity decreases while peak capacity increases. The addition of ES in scenario 3 enables more VRE expansion while further reducing the need for base capacity. Finally, the amount of ES in scenario 4 increases substantially, as it is now the only fully dispatchable resource because thermal generators are no longer considered in the generation mix. The resulting system costs are summarized in Table 2, which shows a substantial reduction in costs as VRE and ES are added to the mix (scenarios 2 and 3), but a significant increase when thermal generators are no longer available (scenario 4).

Figure 2: Optimal capacity expansion for different scenarios



[47] European Network of Transmission System Operators for Electricity (ENTSO-E), (2018), 'Maps and data', *Ten Year Network Development Plan 2018*. https://tyndp-data.netlify.app/tyndp2018/

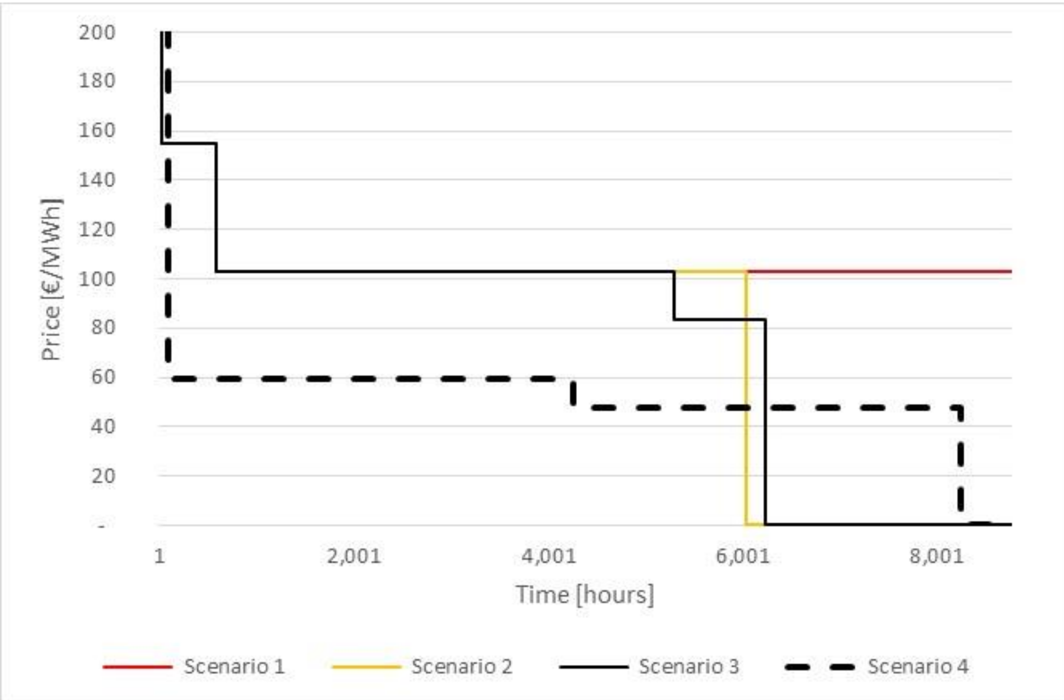
[48] European Commission Joint Research Centre (2019), European Meteorological derived High Resolution RES generation time series for present and future scenarios (EMHIRES), https://data.jrc.ec.europa.eu/collection/id-0055

Table 2: Average price, annual cost and load curtailment results for difference scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Average price (€/MWh)	111.7	79.6	79.8	80.4
System cost (Billion €)	69.9	49.6	49.5	53.1
Load curtailment				
Duration (hours)	16	16	16	88
Energy (GWh)	18.6	51.7	53.9	316
Max (GW)	2.4	11.4	11.9	18.1

Figure 3 illustrates that the introduction of VRE and ES into the system changes the equilibrium prices and introduces new price segments in the price duration curve. Indeed, the price drops to zero during VRE curtailment, and is set by opportunity costs during ES charging in scenario 3. In scenario 4, the prices during ES charging and discharging are functions of capital costs. Note that the actual price levels are dependent on several factors, such as the degrees of freedom with respect to charging capacity, discharging capacity, and energy capacity.

Figure 3: Price duration curves for the four scenarios



The equilibrium prices, summarized in Table 2, lead to cost recovery for thermal, VRE, and ES across all four cases, as expected from the analytical findings. A key assumption contributing to this cost recovery result is that ES is treated as power constrained only in the duration curve formulation (i.e., no constraint or cost is applied to the energy capacity of ES). The average energy price drops substantially when VRE and ES are introduced to the system (scenarios 2 and 3), and only sees a small increase in scenario 4 with VRE and ES only.

The model formulation does not enforce a fixed level of reliability, but rather makes an economic trade-off between the cost of scarcity (VOLL) and the cost of adding capacity to the system. Table 2 confirms that the duration of load curtailment remains constant across scenarios 1 to 3, but the amount of energy curtailed increases in scenarios 2 and 3 due to a steeper net load duration curve (more VRE generation). Moreover, scenario 4 sees a substantial increase in load curtailment, in terms of both duration and energy. This is because a different set of optimality conditions occur during scarcity when thermal units are no longer part of the mix. In this case, the cost of load curtailment, VOLL, is weighed against the cost of additional ES capacity. The latter is used not only to meet peak demand on the margin (as is the case with the peak plant in scenarios 1 to 3), but also to shift energy from surplus to deficit hours and reduce VRE curtailment.

Conclusion

The results from our simple model-based analysis indicate that energy-only markets with scarcity prices set to VOLL may continue to provide adequate incentives for operations as well as investments and cost recovery after the introduction of VRE and ES. Moreover, ES plays an increasingly important role in price dynamics as thermal plants are pushed out of the competitive equilibrium. If the system reaches a state where flexible generators with non-zero marginal costs are no longer part of the optimal resource mix, equilibrium prices need to directly reflect the capital costs of VRE and ES. This raises questions around which cost elements should be allowed in short-term energy market offers and the need for additional capacity remuneration constructs. The findings also highlight the importance of long-term energy contracts in zero-carbon markets dominated by VRE and ES, where capital costs can be more directly reflected in market clearing prices. An important caveat is that demand flexibility is not considered as a resource in the stylized system. We expected that price-responsive demand will have a substantial impact on price dynamics and optimal investments, a topic we will explore in future work.

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ON TRUTHFUL PRICING OF BATTERY ENERGY STORAGE RESOURCES IN ELECTRICITY SPOT MARKETS

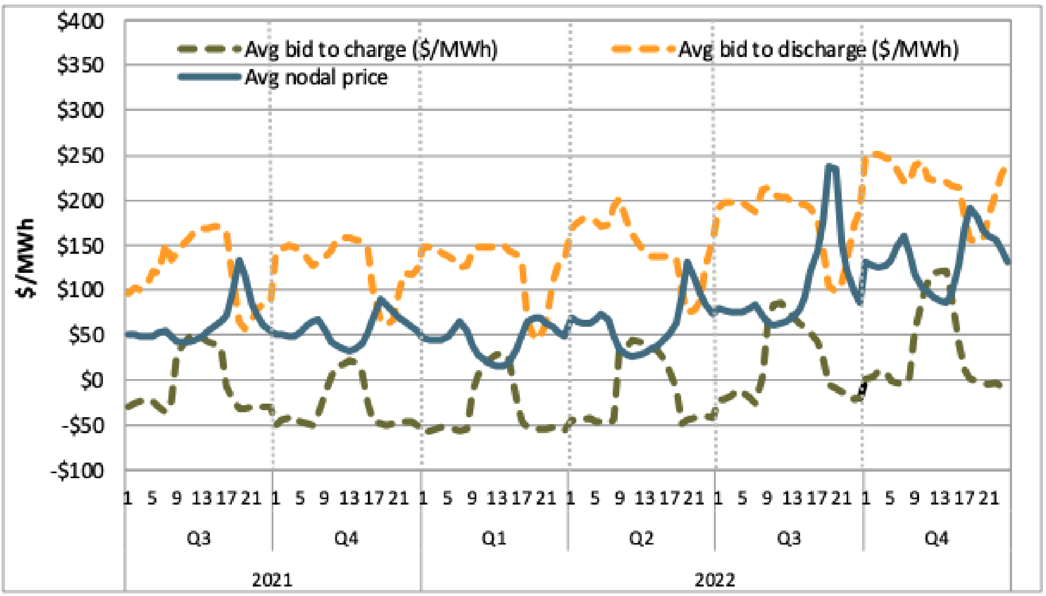
Bolun Xu and Benjamin F. Hobbs

The capacity of grid-scale battery energy storage (BES) in the United States exceeded 14 gigawatts (GW) in 2023, according to the US Energy Information Administration, marking a significant increase from the less than 1 GW recorded in 2018. This upsurge in installations benefits from advancements in storage technologies, decreasing costs, and pivotal regulatory modifications. Notably, US Federal Energy Regulatory Commission Order 841, enacted in 2018, mandates that all independent system operators (ISOs) and regional transmission organizations across the US must permit energy storage systems to participate competitively across all markets. Several states in the US have instituted subsidies and requirements for grid-scale battery storage. As a result, in California alone, BES installations have exceeded 7.3 GW, compared to daily electricity demands that fluctuate between 20 GW and as high as 50 GW.

Initially, the high installed cost of batteries limited their installation, and their highest-value use in US markets was for frequency regulation. There, the system operator provides a signal every 4 seconds for regulation providers to move up or down to maintain supply-demand balances and prevent deviations from scheduled interchanges with neighbouring systems within the five-minute scheduling intervals typical of US real-time markets. However, the markets for such regulation are limited, and with the recent growth in battery installations, they are increasingly used to arbitrage energy price differences across the day. Depending on the system operator, batteries can submit either self-schedules for charging and discharging, which are subject to operator overrides during stressed system conditions; economic offers to discharge (sell energy), and bids to set (buy energy) that the operator then considers in its market optimization; or a combination of offers and bids with a specified state-of-charge target for particular times.

Figure 1 illustrates the interaction of energy prices and storage bidding behaviour in the California Independent System Operator (CAISO) real-time market. It shows that average bids to charge exceed energy prices in the solar-abundant mid-day, at which time the batteries would then absorb some of the system's excess supply. Later, during the early evening, when loads are high but solar output tails off, the battery offers to sell are below prices, and the system draws on storage to meet peak net loads.

Figure 1: Hourly average battery offers to discharge and bids to charge in the real-time CAISO markets in 2021 and 2022



Source: California Independent System Operator, Department of Market Monitoring (2023), *Special Report on Battery Storage*, www.caiso.com/Documents/2022-Special-Report-on-Battery-Storage-Jul-7-2023.pdf.

Although this buy low/sell high strategy for intertemporal energy discharge seems simple in concept, in practice it has proven challenging for power markets to implement efficiently. Distinct from the pricing mechanisms of traditional thermal power plants, the cost models and contributing factors of BES remain underacknowledged in today's electricity market settlements because markets were originally designed primarily to accommodate generation that can be dispatched when needed without restriction, and not resources that couple markets at different times.

A fundamental principle of the design of electricity markets of such resources is the need to facilitate truthful bidding of marginal costs (traditionally calculated as fuel cost times a heat rate) to maximize market efficiency. This principle is operationalized in the US through a centralized market clearing mechanism that relies on locational marginal pricing, encouraging generators to bid their true marginal fuel costs. Conversely, markets lacking adequate competition can incentivize participants to engage in capacity withholding, deliberately limiting their resource offers at fair market prices with the anticipation of inflating market prices to bolster profits. However, the relative transparency of commodity fuel prices, such as coal and gas, has allowed power market monitors to examine bids from conventional generators, ensuring that these bids accurately reflect the marginal fuel costs rather than being intended to withhold capacity from the market.

The text that follows discusses two major sources of difficulties in estimating the costs of battery operation, which challenge battery owners, market operators, and market monitors: opportunity costs and degradation costs.

The role of opportunity costs

Truthful bidding of costs remains a goal of market design, even as generation mixes have shifted to variable renewables and, increasingly, battery storage. But in today's power systems, opportunity costs rather than fuel costs make up an increasing proportion of variable costs, and are challenging for market participants to estimate and for market operators to monitor.

Unlike conventional generators, energy-limited resources, such as BES, are compelled to engage in capacity withholding within the confines of existing market frameworks to account for their future opportunity costs. From the perspective of resource owners, the maximization of operating profit is achieved by allocating limited energy supplies during periods of peak prices within a projected future time frame. Consequently, during phases of low pricing, the resource would set the anticipated future high prices as their opportunity cost. This strategy results in effective capacity withholding by storage resources. This is a rational strategy by competitive (price-taking) battery owners, and is not per se the exercise of market power. Moreover, this practice of capacity withholding by competitive storage resources aligns with the maximization of overall system net benefits, as it ensures the allocation of energy during times when the system most urgently requires additional supply, thereby mitigating price spikes.

One analysis recognized the economic rationale behind this strategy, noting that 'if a unit is energy limited, its offer price will necessarily surpass the unit's incremental cost,'[49] distinguishing this form of economic withholding from the overt exercise of market power. The CAISO has acknowledged the unique operational cost structure of storage systems, allowing storage bids to 'include the highest (predicted) price, corresponding to the storage duration of the resource.' In particular, for a battery with a typical 4 hours of storage, the so-called default energy bid for battery discharge in the CAISO real-time markets is the fourth-highest hourly price in the rest of the day, as calculated in the day-ahead market run. This acknowledgment permits storage facilities to submit bids that exceed their physical discharge costs, predicated on anticipated future price surges.

The complications of opportunity costs

Opportunity costs need to be estimated by battery owners, market operators, and market monitors. Owners use opportunity costs to develop bids/offers. Market operators consider opportunity costs when deciding if and when to schedule charging and discharging, and what energy and ancillary service products a resource should be scheduled to provide in their day-ahead and real-time markets. Finally, market monitors need to assess whether bids/offers are competitive (reflect marginal costs, including opportunity costs) or if they instead represent attempts to exercise market power (either by withholding discharge or ancillary service capacity to increase selling prices, or by restricting charging to decrease charging prices).

In a world where prices can be perfectly forecasted for energy and ancillary services in all markets, opportunity costs are readily calculated by deterministic dynamic optimizations. However, uncertainty greatly complicates their estimation, especially because future prices are subject to both risk (when probability distributions are relatively well known) and uncertainty (when the distributions are unknown and disagreed over), and because of the widespread use of simplified models by market participants and operators.

First, market fundamentals that drive price formation—load, variable renewable output, transmission and generator outages, fuel prices, and bidding behaviour—are both risky and uncertain, even on hourly time scales. Energy stored in batteries is a valuable hedge in these circumstances, and opportunity costs should be quantified as an expected value over a wide range of possible net loads and prices.

Second, although market software in some US ISOs is designed to clear supply and demand over multiple time intervals while allowing tracking and optimization of battery state of charge, the markets treat demand and renewable forecasts as deterministic, and do not optimize over explicit probability distributions of net loads. Rather than using stochastic optimization, markets rely on procuring several types of operating reserves to enable systems to adapt resource dispatch and commitment to maintain reliable and economical operation, each type having a required rampability (e.g. 10-minute spinning reserves or 30-minute replacement reserves) and rules for deployment (activation rules for 4-second frequency reserves, enumerated contingencies for spinning reserves, and economic dispatch in the case of flexible ramp product). Batteries can provide and be paid for providing these services, but they are only very rough approximations of the hedging value of stored energy. Even if stochastic optimization could be used to clear markets, stochastic processes of market inputs would be highly simplified.

Third, the duration of market intervals (1 hour day-ahead, and 15 minutes for real-time unit commitment) are too short to capture the full volatility of market marginal costs, which results in underestimation of the option value of batteries, especially when defining day-ahead schedules. This is true even if hourly averages of real-time prices can be reasonably projected day-ahead, because disregarding the value of storage to manage within-hour price spikes can cause significant biases in charge/discharge schedules and opportunity costs of stored energy.

A fourth issue is the end effects, where the value of stored energy beyond the market software's time horizon is, in effect, assumed to be zero, which will in general suppress opportunity costs. For short duration (4-hour storage or less), this is not so much of a problem in 24-hour day-ahead markets as it is in real-time markets whose time horizons are typically 2 hours or less. To prevent premature discharges, California allows resource owners to specify ending state-of-charge levels. But even so,

[49] Harvey, S.M., and Hogan, W.W. (2001), 'Market power and withholding', Harvard University, Cambridge, MA.

storage owners have complained about seemingly irrational charging and discharging schedules in real time which have resulted in financial losses and sometimes failed to reserve energy for critical evening peaks.

A fifth issue is the need for default energy bids under ex-ante market power mitigation that are preferably based on verifiable and publicly available costs. Opportunity costs, based as they are on necessarily subjective expectations about future prices, are particularly fraught. In California's real-time markets, the market operator has chosen to base those cost estimates on day-ahead market prices, but the large deviations that can occur between day-ahead and real-time prices, especially during times of system stress, mean that those estimates can be highly inaccurate. In such cases, low default energy bids can result in mitigation of storage energy offers down to levels that result in significant premature discharging and exacerbate shortage conditions later in the day.

Finally, opportunity costs can arise when storage can provide both energy arbitrage and reserve services. The most valuable use for storage in some markets is frequency regulation because of its quick response. However, storage scheduled for up-regulation for multiple hours may discharge a significant amount of energy if its regulation is activated, while being procured for down-regulation reserves can result in unanticipated charging. Both situations change the feasible region for state-of-charge, and may significantly reduce the value of storage for energy arbitrage. Market software, as in California, considers an expected adjustment in state-of-charge in future intervals for resources providing reserves. But these expected values may be very different from actual changes, especially if the system is subject to unexpected stresses—which are, of course, when energy arbitrage may also be most valuable.

The complexity of pricing battery degradation

Degradation, a relatively novel cost factor predominantly associated with BES, significantly impacts battery economics. Electrochemical batteries, particularly lithium-ion batteries, which constitute most grid-scale BES, are subject to power and capacity degradation. This degradation—a consequence of intricate electrochemical reactions within the battery's anode, cathode, and electrolyte—results in a decline in the battery's usable energy and power capacity through cycling. Experimental evidence indicates that, under aggressive cycling conditions, certain battery types may reach their end of life after approximately three hundred cycles. Assuming a daily cycle, this equates to a reduced usable lifespan from about 10 years to 2 years. Therefore, the influence of degradation is so substantial that it necessitates inclusion within the pricing factors of electricity markets. But this also faces several technical and economic challenges.

Firstly, the degradation pricing must be built on a predictive model that balances the inherently complex and technology-specific degradation mechanisms with the need for a simple and universal model in market clearing. A model that quantifies the marginal degradation of a battery during grid charging or discharging activities is essential to incorporate degradation costs into electricity market pricing. This model should be analogous to the marginal heat rate curve employed for thermal generators, coupled with a monetized cost of degradation akin to thermal generators' fuel costs. Given the complexity of battery degradation mechanisms, which vary across different battery types, electricity markets require a simplified, yet generalizable model to represent diverse storage technologies. From the perspective of market clearing and pricing efficiency, the selected degradation model should exhibit several critical characteristics, such as convexity and independence of past dispatch results. Primarily, the model should be convex to ensure that it imposes minimal computational complexity on market-clearing software and facilitates efficient pricing for revenue adequacy. Additionally, the model should calculate degradation only from the operation within the settlement period, which could range between 5 minutes and 24 hours depending on the market segment, independent of past and future systems or storage states. Careful modelling must therefore be conducted, as most battery degradation processes will not meet these criteria.

Secondly, the challenge of accurately predicting battery degradation extends beyond the limitations inherent to the degradation model selection. This difficulty persists within the battery research community due to several factors: proprietary battery manufacturing and testing processes, evolving battery technologies and compositions, and the inevitable variances among battery cells resulting from mass production. Predominantly, current battery models are developed from laboratory test data, leading to delays in formulating degradation models for new battery types. Such degradation tests require extensive time, often spanning months or even years, to complete. Furthermore, these models risk extrapolation errors since laboratory tests typically adhere to standardized procedures, whereas real-world grid operations may exhibit irregular and unforeseen patterns. Additionally, battery manufacturers might restrict access to comprehensive degradation data, asserting exclusive rights for degradation estimation or imposing warranty conditions that limit battery usage—such as restricting the battery to a single charge cycle per day. These restrictions hamper the storage or system operator's ability to innovate or optimize battery usage.

Finally, storage operators must determine the monetized value of battery degradation, specifically, the cost associated with the loss of one kWh of usable capacity. An initial consideration might involve calculating this degradation cost by amortizing either the battery's purchase or replacement cost over its diminished capacity. However, this method does not maximize the storage owner's profits. A recent analysis demonstrated that selecting a strategic value for degradation can significantly enhance the life-cycle revenue of a storage project by balancing the trade-off between lifespan and daily income potential, rather than relying on amortized costs.[50] Essentially, the value of degradation reflects the opportunity cost of reduced battery life; earning more in the present with the battery leads to incremental degradation, thereby shortening its lifespan and diminishing future profit opportunities. Thus, in determining the optimal value of degradation, one must consider it analogous to the opportunity value of stored energy, as previously discussed, with the future time horizon extending over the battery's entire expected lifespan, which may range from 5 to 20 years. This introduces further uncertainty in pinpointing the precise value of degradation.

Implications for market power monitoring and future market designs

For all the above reasons, estimates of opportunity and degradation costs will be error-laden. There may be significant differences between what resource owners believe those costs are, the costs considered by operators when scheduling storage for energy and reserves, and the values that market monitors may use for detecting the exercise of market power. These disagreements are the source of friction between resources who wish to maximize profits, operators who are concerned with reliability and cost minimization, and monitors who are trying to prevent market gaming.

As the penetration of battery storage increases, market designers and monitors are increasing the complexity of procedures for estimating battery operations costs, so that scheduling energy arbitrage and procuring reserves is economically efficient and promotes reliability, and attempted exercise of market power is readily detected. As an example, recent modifications to the CAISO's market scheduling software attempt to account for (1) state-of-charge-dependent degradation costs, (2) future opportunity costs, (3) future uncertainties through reserve requirements, (4) opportunity costs arising from the flexibility to provide both energy arbitrage and reserves and from stacked services, and (5) complex interactions of day-ahead and real-time markets. Further changes could be considered in the future that would facilitate efficient battery operations, including more accurate degradation cost models, state-of-charge-dependent opportunity costs, multiple intra-day financial settlements, and multi-period financial settlements in real time, rather than the present structure of a single financially binding interval followed by multiple advisory intervals.

Acknowledgments

The responsibility for any opinions or errors belong to the authors. We are grateful for helpful conversations with Danny Johnson and Gabe Murtaugh of the CAISO and Scott Harvey and Jim Bushnell of the CAISO Market Surveillance Committee. Xu was supported by NSF Grant ECCS-2239046, and Hobbs received support from NSF Grant 2330450.

BID FORMATS FOR ENERGY STORAGE ON ELECTRICITY AUCTIONS: BRIDGING THE ATLANTIC

Thomas Hübner and Gabriela Hug

Energy storage technologies are crucial for sustainable power systems but are subject to entirely different operational constraints than power plants or loads. An energy storage first needs to charge before it can discharge. This inter-temporal constraint constitutes a complementarity (also known as economy of scope) between the consumption and generation of power at different times. If the energy storage cannot express those complementarities in the market, it faces the risk of selling never-bought energy—leaving it in a physically impossible state. The answer from auction theory to this exposure problem is the combinatorial auction, which allows the simultaneous trade of multiple goods. This concept is used in the day-ahead electricity auction, with the goods being electric energy at different times.

[50] He, G., Chen, Q., Moutis, P., Kar, S., and Whitacre, J. F. (2018), 'An intertemporal decision framework for electrochemical energy storage management', Nature Energy, 3(5), 404–412.

In European exchanges, agents can use block bids to couple power supply or demand at different hours. Thus, they allow the trade of 'packages' of multiple goods, allowing the agent to express their complementarities. In contrast, in the United States, agents specify their willingness to buy or sell electric energy somewhat indirectly through asset-specific multi-part bids. For instance, an energy storage can bid its cost and operating parameters, like energy and charge/discharge capacity, to the auctioneer. Based on those parameters, the auctioneer will schedule the storage most efficiently as part of a multi-time-step unit commitment optimization. This way, inter-temporal constraints are directly enforced, and complementarities are considered within the market-clearing optimization.

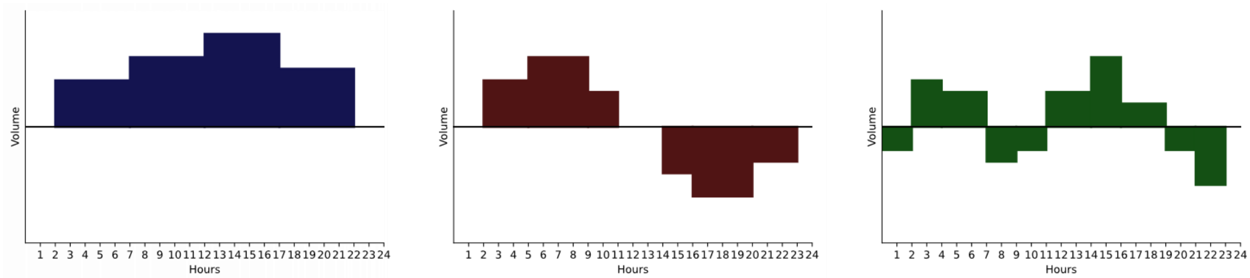
These different bid formats are often seen as part of the broader debate about the centralized or decentralized structure of power markets that differentiates Europe and the US. Ultimately, it is about less: block bids and multi-part bids just define how agents can express their willingness to buy or sell electrical energy in an auction. This article highlights the individual advantages and disadvantages of those two bid formats and argues that a good electricity auction will enable both block and multi-part bids—thus, in a way, bridging the Atlantic.

The European design: block bids

European exchanges like Epex Spot and Nord Pool offer so-called profile block bids, as Figure 1A depicts. Those enable agents to bid on a sell or buy power profile with a price the agent is willing to receive or pay. However, an energy storage would need to be able to bid on a power profile that contains both buy and sell quantities. Currently, this is not possible. Instead, the exchange Epex Spot introduced loop blocks, allowing the linkage of one sell and one buy profile block to be executed together, as depicted in Figure 1B. However, this limits the agent's arbitrage opportunities and complicates the market clearing because a binary variable is necessary to link the sell and buy blocks. The redefinition of a profile block bid to contain a generic profile with both buy and sell quantities, as depicted in Figure 1C, would, therefore, not only increase efficiency but also simplify the auctioneer's market-clearing problem.

Figure 1: Block bids

(A) Profile block bid (B) Loop block bid (C) Generic block bid



By submitting a generic block bid with a limit price so high (or low) that it will always be accepted, an energy storage can conduct a self-schedule in the market. However, this exposes the agent fully to price uncertainty. To limit this risk, an agent can submit *N* block bids within an exclusive group. The auctioneer then chooses the one block bid out of this group that contributes most to social welfare, or none if none of them does. This way, an agent can hedge against *N* different price scenarios instead of being completely exposed to one scenario with a self-schedule. The simplicity of this bidding format is one of the reasons exclusive groups of block bids have already been gaining popularity in European exchanges for a couple of years.[51]

It is important to note that block bids are not the source of nonconvexity in European electricity auctions, but the fill-or-kill condition is.[52] This condition specifies that a bid can either be entirely accepted or not at all. Acceptance is either 0 or 1, and partial acceptance between 0 and 1 is impossible. However, the set {0,1} is nonconvex in contrast to the set [0,1]. Thus, nonconvexity is only introduced in case of a fill-or-kill condition but not if a block bid can be accepted partially. Generally, there is no need to introduce such a fill-or-kill condition for agents who do not exhibit nonconvexity in their preferences. Conversely, for agents with nonconvex preferences, such as thermal generators, a fill-or-kill condition is necessary to avoid the violation of minimum stable generations or making a loss, as fixed costs are not covered.

[51] Herrero, I., Rodilla, P., and Batlle, C. (2020), 'Evolving bidding formats and pricing schemes in USA and Europe day-ahead electricity markets', *Energies,* 13(19):5020.
[52] Madani, M., and Van Vyve, M. (2015), 'Computationally efficient MIP formulation and algorithms for European day-ahead electricity market auctions', *European Journal of Operational Research*, 242(2):580-593.

The problem of missing bids

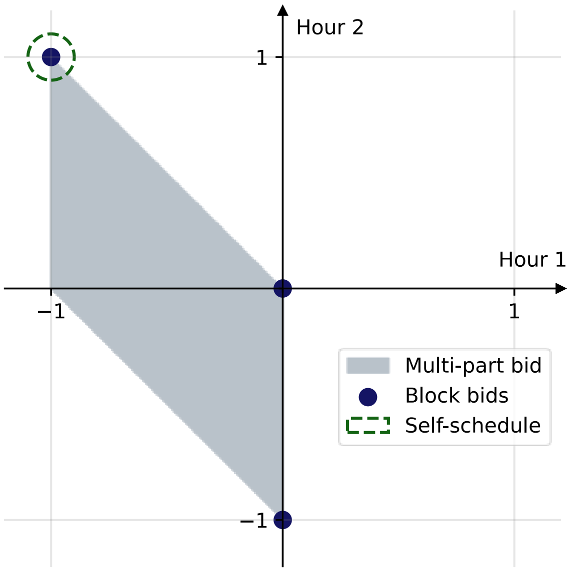
The auction restricts the number of block bids *N* to ensure a tractable market clearing optimization problem. This means that an agent cannot place a block bid for each of their feasible dispatches. Consequently, there is a risk that the welfare-maximizing dispatch does not get cleared if an agent fails to submit the associated block bid. This problem of missing bids is inherent in combinatorial auctions and not exclusive to electricity auctions but is also observed, for example, in auctions for spectrum licenses or TV ad slots.[53]

At first glance, considering the multitude of possible operating states, the risk of being suboptimally dispatched with only offering *N* possible schedules in an exclusive group looks high. However, not all technologically feasible states are also economically relevant. In electricity markets, price information is exceptionally high, and agents can thus efficiently predict economically relevant bids. Reasons for this are, among others, active forward markets, load and generation patterns, and the agents' experience caused by the daily trading of electricity. This ability to forecast the prices to a high degree of accuracy is why the European bid formats were proposed in the first place: if agents can quite accurately predict their ex-post optimal operating state, there is no need for a central entity to carry out the scheduling.[54]

The American design: multi-part bids

The problem of missing bids and the resulting necessity for agents to forecast prices can be avoided by multi-part bids, which allow the agent to specify all their possible operating states compactly. To illustrate this, consider an energy storage bidding in an auction for electricity in hours 1 and 2. The energy storage can charge and discharge with 1 MW, has a capacity of 1 MWh, and an initial state-of-charge of 1 MWh. We assume no losses or degradation costs. The grey area in Figure 2 depicts the possible operating states. The storage can, for example, discharge all its energy in hour 1 and recharge in hour 2, represented by point (-1,1), or keep idle in hour 1 and discharge in hour 2, represented by point (0, -1).

Figure 2: Self-schedule, block, and multi-part bids



If the agent predicts high prices in hour 1 and low prices in hour 2, a possible self-schedule could be (-1,1): discharging in hour 1 and charging in hour 2. If the agent is unsure if high prices will be realized in hour 1 or 2, they can place two block bids in an exclusive group: (-1,1) and (0,-1). This way, the agent can ensure its stored energy is discharged in the most valuable hour. Note that in Figure 2, point (0,0) is also marked: it is always possible that the auction rejects all bids if none would contribute to social welfare. This contrasts with a self-schedule, which would never be 'rejected' under normal circumstances as no price is attached.

[53] Bichler, M., Milgrom, P., and Schwarz, G. (2023), 'Taming the communication and computation complexity of combinatorial auctions: the FUEL bid language', *Management Science*, 69(4):2217-2238.
[54] Ahlqvist, V., Holmberg, P., and Tangerås, T. (2022), 'A survey comparing centralized and decentralized electricity markets', *Energy Strategy Reviews,* 40:100812.

The necessity to forecast prices disappears when the agent decides to bid their parameters via a multi-part bid. Suppose the agent bids 1 MW charge/discharge volume, an energy capacity of 1 MWh, and an initial state-of-charge of 1 MWh. The auctioneer can then enter those parameters into a predefined mathematical model of an energy storage system to represent the storage by the grey area in the welfare maximization problem. In this way, the agent has a compact way to express all their possible operating states. Therefore, the storage system can avoid the risk of missing bids as the auctioneer ensures that it is dispatched most efficiently based on the submitted parameters.

In this context, it is also opportune to consider market power. For instance, there is concern that large wind power farms can strategically withhold capacity in the markets by claiming wrong forecasts. A similar technique is also conceivable for block bids in an exclusive group: as agents must determine their own *N* schedules based on their price predictions, it might be possible to withhold capacity by claiming a wrong forecast. Although not protected against strategic behaviour either, one might argue that a multi-part bid is less prone to the exercise of market power.

In a highly regulated market like the one for electricity, there are always other approaches to mitigate the abuse of market power. Especially as agents bid daily in this market, detecting the abuse of market power is easier than in other markets. At least for energy storage systems, the concern of abuse of market power is not as significant as for thermal generators.

The problem of barriers to entry

The probability of being suboptimally dispatched is high with a self-schedule, lower with an exclusive group of N>1 generic block bids, and zero with an accurate multi-part bid. However, multi-part bids are defined by the auctioneer, and an agent can only express their preferences through the given parameters. Consequently, the multi-part bids are likely inaccurate or unsuitable for agents with preferences that deviate from the common ones defined by the auctioneer. The same applies to agents with a new technology or different business model for whom the existing multi-part bids do not work. New multi-part bid formats would have to be defined first. This way, multi-part bids constitute a barrier to entry for new entrants.

However, new technologies and business models will enter the market as the energy transition continues. It is, therefore, crucial to limit barriers to entry as much as possible. For instance, an electric vehicle fleet with vehicle-to-grid technology can be operated as a dynamic battery system with changing capacity depending on the number of idle cars. It might be challenging to design sufficiently accurate multi-part bids for these new agents, while the precise representation over a multi-part bid is already tricky for existing agents such as pumped hydro storage.[55]

In US markets, agents who cannot represent their preferences through existing multi-part bids are recommended to self-schedule. As Figure 2 suggests, an exclusive group of *N* block bids can be seen as an intermediate solution between a self-schedule and a multi-part bid: the agent can still ensure a schedule that fits with their individual preferences but can contain the risk of being suboptimally dispatched by offering *N* possible schedules instead of offering only one through a self-schedule.

Why not have both bid formats?

When discussing the choice of bid formats in electricity auctions, it is essential to refrain from entangling it with other debates. Debates like spatial pricing (zonal vs nodal) or uniform pricing in the presence of nonconvexities (convex hull pricing vs IP pricing vs European pricing) arise for both block and multi-part bids and should be conducted chiefly independently of the question of bid formats.

Unlike other debates that divide the US and European markets, the discussion of bid formats need not be divisive but can be unifying: it is not difficult to use the best of both worlds and let agents decide which format to use. In this way, the strengths of both bid formats can be utilized, and the main problems of each, the problem of missing bids for block bids and the problem of barriers to entry for multi-part bids, can be mitigated. In other words, the complementary nature of block and multi-part bids makes it possible—at least in this debate—to reconcile two seemingly distant ideas from opposite sides of the Atlantic.

[55] Baldick, R., Chen, Y., and Huang, B. (2023), 'Optimization formulations for storage devices with disjoint operating modes', *Operations Research,* 71(6):1978-1996.

LARGE-SCALE ELECTRICITY STORAGE

Chris Llewellyn Smith

As electricity supply is decarbonized, an increasing portion will be provided by wind and solar, which are the cheapest forms of low-carbon generation. However, the wind does not always blow and the sun does not always shine. Large-scale wind and solar generation must therefore be complemented by large-scale flexible supply, and/or excess supply must be stored and used later. But the only large-scale low-carbon sources are nuclear, gas with carbon capture and storage (CCS), and bioenergy with CCS—which are expensive, especially if operated flexibly—and, in some regions, hydro. Using stored excesses, which would otherwise be curtailed, is therefore an attractive option, if it is viable and economically competitive at the required scale.

This article draws on a recent Royal Society study of large-sale electricity storage that focuses on the storage that Great Britain (GB) will need in the net-zero era (taken to begin in 2050).[56] The major conclusions are also potentially relevant for other regions. The challenges of designing markets that will incentivize the necessary investments and secure smooth operation, which the study identified, are discussed in the accompanying article by John Rhys.

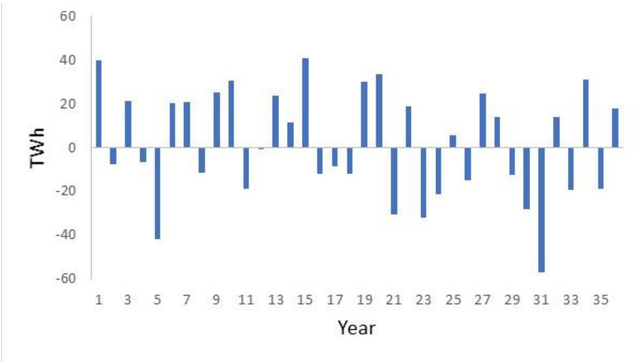
Assessing the need for storage

In order to assess the need for storage, or flexible supply, it is necessary to compare potential wind and solar supply with electricity demand over as long a period as possible. The Royal Society study used

- Hour-by-hour estimates, made by Renewables.ninja,[57] of wind and solar supply in GB over the 37 years 1980–2016, assuming a 20/80 mix of solar and wind generation, which minimises curtailment by, on average, approximately matching the difference between the assumed demand in winter and in summer (the problem is volatility, not seasonality).
- An hour-by-hour model of a possible 2050 demand for electricity fed into the grid (before transmission and distribution losses) of 570 TWh (roughly twice today's electricity demand), kindly provided by AFRY[58], which was used in all 37 years studied. Other levels were also considered.

The resulting surpluses and deficits are shown in Figure 1 with supply scaled to average 570 TWh/year over the 37 years studied.

Figure 1: Surpluses and deficits in 'years' April-March in the period 1980–2016



Notes: Assumptions are as described in the text. In order not to separate contiguous quarters 4 and 1, which would dilute the effect of severe winters, years April to March are used here i.e. year 1 represents April 1980 to March 1981 etc.

This figure, and the assumptions about supply and demand, lead to the following observations and questions:

1. With average supply equal to average demand and perfect storage it would be possible to meet demand throughout the 37 years. However, in order to meet demand in years 29–31, it would be necessary to use energy that had been in

[56] Royal Society Storage Report. https://royalsociety.org/-/media/policy/projects/large-scale-electricity-storage/Large-scale-electricity-storage-report.pdf
[57] Renewables.ninja. https://www.renewables.ninja/
[58] AFRY Bid 3 Power Market Model. https://afry.com/en/service/bid3-power-market-modelling

the store since year zero. This is the result of long-term variations in wind supply (related to the North Atlantic and Arctic Oscillations), which require storage of large amounts of energy for decades in GB, and in other areas as discussed below (in contrast, interannual variations in solar are relatively small, as is its contribution in GB).

2. According to a study by the Met Office,[59] there is a 10 per cent chance per decade of a winter month having less wind than in any of the winter months in the 37 years studied. To allow for this, and for the possible effects of climate change, 20 per cent contingency was added to the long-term hydrogen store in the Royal Society study (this only adds about £1/MWh to the average cost of electricity.) By the time the contingency might be built, improved modelling should reveal whether 20 per cent is enough.

3. The analysis used historical weather data, which may not be representative of the weather in 2050. According to experts from the British Meteorological Office, 'The year-to-year variability of wind is expected to continue at today's level and to have a bigger impact on electricity supply than climate change.'[60] If this is correct (it is not a theorem), then it should be safe to use historical data, with some contingency included.

4. Demand varies with the weather, so using AFRY's model of demand (which is based on the weather pattern in 2018) for all the years studied is only an approximation. A study carried out after the Royal Society report was finished showed that including correlations between demand and the weather increases the size of the required storage system by about 10 per cent.[61] This adds less than 1 per cent to the average cost of electricity, which is dominated by the cost of wind and solar supply.

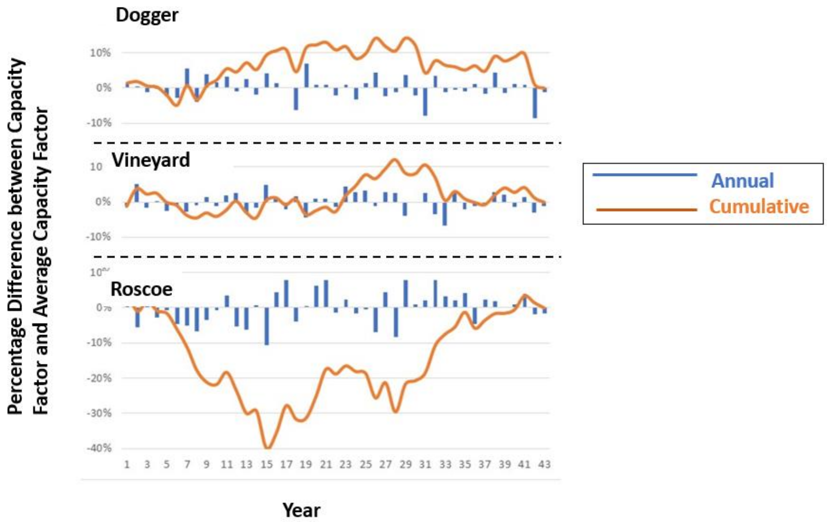
5. With a resolution of 1 hour, it is not possible to analyse the need for storage that can respond very quickly to deal with trips and surges in demand, such as those generated by the proverbial cup of tea at half-time in major football matches. Meeting very short-term needs takes very little energy and can be neglected in studying longer-term storage needs, but the cost of meeting the very short-term needs using batteries is included in the cost estimates given below.

Many studies of storage (including those used by the UK's National Infrastructure Committee[62] and Climate Change Committee[63] and a study by the Massachusetts Institute of Technology[64]) look at individual years rather than a sequence of years. This seriously underestimates the need for large-scale storage, and conversely overestimates the need for other flexible supply (e.g. from gas plus CCS). Studies of individual years (however many), which cannot cast light directly on long-term storage needs, underestimate the need for storage on all but relatively short time scales. This is because the constraint that the stored energy must be the same on 31 December as it was on 1 January limits the storage time and the amount of energy that can be put into and taken out of store. Meeting demand therefore requires more flexible supply from other sources than would have been found if storage were not prevented from importing energy from, or exporting it to, other years (this effect is particularly large in low wind years: it could be compensated by increasing the wind capacity, but this would lead to excess generation in other years, which would have to be curtailed).

The importance of studying long continuous sequences of years when evaluating the need for storage is not limited to GB. Figure 2 compares variations in potential wind generation at the Dogger Bank in the North Sea, Vineyard off Cape Cod, and Roscoe in central Texas. Relative to what it would have provided if the wind were the same in every year, there was a surplus of wind at the Dogger Bank in 1980–2008 and a deficit in 2009–2022, and a surplus at Vineyard (which is also affected by the North Atlantic Oscillation) in 1980–2007 and a deficit in 2008–2022, while at Roscoe there was a deficit in 1980–1994 and a surplus in 1995–2022.

[59] Kay, G., Maidens, A., Thornton, H., Dunstone, N., Scaife, A., and Smith, D. (2020), 'Preliminary assessment of low winter winds over the North Sea', unpublished private communication.
[60] Bloomfield, H., et al. (2021), 'Quantifying the sensitivity of European power systems to energy scenarios and climate change projections', *Renewable Energy*, 164, 1062–1075.
[61] Royal Society Storage Report, supplementary information, p. 199.
[62] *2023 National Infrastructure Assessment*; *Delivering a Reliable Decarbonised Power System* 2023; MIT (2022), *Future of Energy Storage*.
[63] OV.UK. 2022 Benefits of long-duration electricity storage. See https://www.gov.uk/government/publications/benefits-of-long-duration-electricity-storage
[64] MIT. 2022 The Future of Energy Storage. See https://energy.mit.edu/research/future-of-energy-storage/

Figure 2: Variations of capacity factors, in the period 1980–2022 for wind farms at the Dogger Bank in the North Sea, Vineyard off Cape Cod, and Roscoe in central Texas



Notes: These results are for the turbines that will be or already are installed at these sites, whose power curves have similar shapes. The volatility at Dogger is less than seen in Figure 1 for GB as a whole, presumably because it is a windy area and the wind capacity is often near 100 per cent.

Meeting the need

Very large-scale long-term storage needs can only realistically be met by storage that has a very low capital cost per unit of energy stored and suffers negligible self-discharge losses. This points to using some form of chemical rather than thermal or other form of large-scale storage. The options are to use:

1. Hydrogen, which can be stored deep underground in solution mined-salt-caverns.

   This has been done at scale in Texas since 1983, and at a smaller scale (since 1972) on Teesside in England, where there are suitable salt deposits in E Yorkshire, Cheshire and Wessex. It may be possible to store hydrogen in aquifers, but this is at low technology readiness level (TRL) and has not been done—or in depleted gas fields, which is at slightly higher TRL according to the IEA,[65] and is being trialled for the first time in Austria. The energy company Centrica says it is 'confident' that it will be able to store 17 TWh (lower heating value) in the depleted Rough gas field off Yorkshire, which would be a big step towards meeting GB's need for hydrogen storage. Whether it is possible to use other depleted gas fields, which would help to avoid grid congestion resulting from siting storage in a limited number of areas, needs to be established case-by-case.

2. Ammonia, which can be stored as a liquid in large tanks almost anywhere, although compared to hydrogen the cost would be somewhat higher, and the round-trip efficiency would be lower.

3. Electro-fuels, such as e-methanol, which are made from hydrogen and CO_2 and are quite likely to play a role in powering transport (although CO_2 may be in short supply or very expensive to capture once point-sources are phased out). For storing electricity, it is generally cheaper and more efficient to store hydrogen.

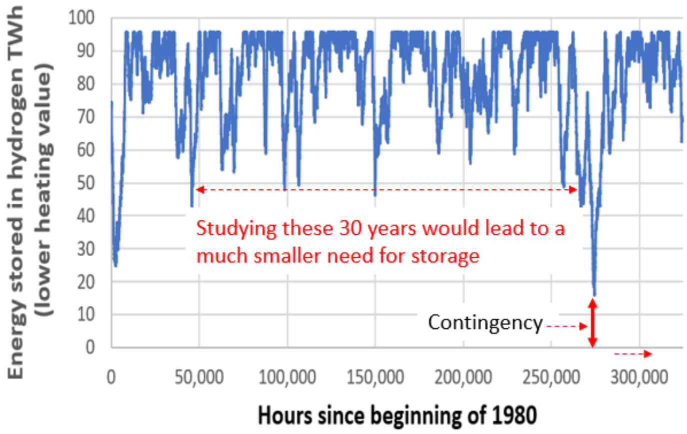
It is instructive to begin with a 'benchmark model' in which all GB's electricity is provided by wind and solar, supported by hydrogen and some batteries, and then consider the addition of other sources of supply and other forms of storage. The minimum electrolyser power must be greater than the average rate at which the store is depleted. With more power, the store can be charged more rapidly and its capacity can be smaller, but there would be no point installing more electrolyser power than the maximum wind power. Between these limits, the combination of electrolyser power and storage capacity is chosen to minimize the cost.

There is also a trade-off between the level of wind and solar supply and the size of the storage system, which decreases as supply increases and more demand can be met directly. The level of hydrogen in the store is shown in Figure 3 for the

[65] Van Gessel & Hajibeygi (2023), *UHS Technology Monitoring Report*.

parameters that minimize the overall cost of electricity, using the central values of the costs and other parameters found in the Royal Society study. The large variation in the level again demonstrates the need for some very long-term storage (some of the energy used in year 31 has been in the store since 1980), and the importance of studying as long a continuous sequence of years as possible when assessing the need for storage.

Figure 3: Energy content of hydrogen, over the years 1980-2016, in stores with a capacity of 95.6 TWh (including contingency) charged by 77.7 GW of 74 per-cent efficient electrolysers, in the benchmark model



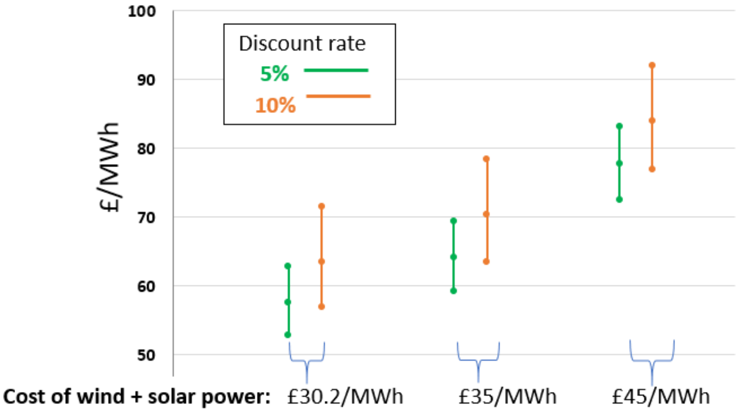
Adding constant baseload generation, provided for example by nuclear and/or bioenergy with CCS, would reduce, but not remove, the need for storage—for example by about 25 per cent with baseload of 200 TWh/year (35 per cent of demand). Hydrogen can also provide storage on time scales down to a few seconds. Whether it is desirable to add other types of large-scale stores (with higher cost but also higher efficiency) depends on costs and feasibilities. They would reduce, but again not remove, the need for the very long-term storage provided by hydrogen: for example, adding multiple large ACAES systems that could together deliver 2.4 TWh_e per cycle would reduce the size of the hydrogen system by some 40 per cent.

The protocol used to decide which type of store should be charged or discharged assigns a marginal value to the energy in each store, related to round trip efficiency and the level in the store. Energy is preferentially put into the stores with the highest marginal value and withdrawn from stores with the lowest marginal value. Although less energy is stored in ACAES than in hydrogen, ACAES is cycled more rapidly, and a system able to provide 2.4 TWh_e/cycle would deliver 52 TWh_e/year, while the hydrogen system operating in parallel, which can deliver 32.5 TWh_e/cycle, would deliver 36 TWh_e/year.

Costs

Figure 4 shows estimates of the average 2050 cost of electricity in the benchmark model for different cost estimates and assumptions. The bottom of the range is above the average cost in 2010–2020. The top is higher than in the last decade, but much lower than it was in 2022, and lower than in much of 2023. The cost/MWh depends weakly on the temporal profile of demand, but not on its level (unless it is high enough to require deploying some wind turbines in more remote areas at higher cost). With demand increased from 570 to 700 TWh/year by more electrification of heat, which makes the profile more skewed between winter and summer, the average cost of electricity was found to increase by just under 2 per cent.

Figure 4: Projected 2050 cost (in 2021 prices) of electricity fed into the grid (before transmission and distribution losses) in the benchmark model, including contingency and an allowance for transmission from wind and solar farms to stores, for different assumptions about the cost of storage, the discount rate, and the cost of the assumed 80/20 mix of wind plus solar power.



Notes: The cost includes £3/MWh for transmission from wind and solar farms to stores and £1/MWh for providing 15 GW of 1-hour batteries. It is dominated by the cost of wind plus solar supply, which contributes £40/MWh, £45/MWh, or £60/MWh to the total cost, assuming it costs £30.2/MWh (IEA's projection for Europe in 2040 adjusted for UK load factors), £35/MWh (BEIS's low 2020 projection for 2040), or £45/MWh BEIS's high 2020 projection for 2040.

The assumed capital and operational costs, lifetimes, and efficiencies are discussed in detail in the Royal Society report[56]. When comparing estimates, it is important to take account of the scale. For example, the cost/(mass stored) of storing hydrogen in solution-mined salt caverns varies approximately as 1/(square root of mass stored), and depends on how many caverns share common surface facilities. The report finds that four-stroke engines or proton exchange membrane fuel cells will probably be cheaper than using turbines to convert hydrogen to electricity.[56]

ACAES was studied as an exemplar of stores that could be combined with hydrogen (but could not replace it in providing long-term storage), providing the benefits of its greater efficiency with the lower cost of hydrogen storage per unit of energy stored. The costs and efficiencies of large ACAES systems are poorly known. However, for a wide range of assumptions, it was found that combining ACAES with hydrogen would be likely to lower the cost relative to that found with hydrogen alone (by up to 5 per cent, or possibly more), although this is not assured.

The report also considered the effects of adding:

- Baseload generation, which as discussed above, would lower but not remove the need for hydrogen storage. It would only lower the cost if nuclear cost less per MWh than the cost in the benchmark model without nuclear.
- Gas with CCS, which could not completely replace hydrogen storage without leading to unacceptable levels of carbon and methane emissions. A limited amount could however lower costs, depending on multiple unknowns, including the costs of storage, wind and solar power, and gas plus CCS, and the price of gas and the carbon price. The effect of leaked methane is conventionally described by comparing the climate impact after 100 years of emitting a pulse of a tonne of methane and a tonne of CO_2. Given the urgency of tackling climate change, 100 years seems far too long, and more realistically the effects of switching on new sources should be compared rather than pulses. During the first 20 years after a new gas-plus-CCS (or blue hydrogen) plant is switched on, the temperature rise per tonne of leaked methane would be 128 times that per tonne of fugitive CO_2. This large factor makes it imperative to stringently limit leakage or forgo large-scale CCS.
- Blue hydrogen, which could play a role in power generation, if it is being produced and stored at scale for other purposes, but again it could not replace hydrogen storage without leading to unacceptable levels of emissions.
- Supply from interconnectors. Connecting wind and solar farms in different locations obviously reduces the short-term

variability of supply, and the need for short term storage – as seen e.g. in a study of the North and Baltic sea areas.[66] However, interconnection cannot remove the need for long-term storage, even in an area as large as the contiguous USA,[67] which spans different climates and weather systems in four time zones. Interconnectors will help manage GB's electricity supply, but there are pan-European wind droughts, accompanied by cold periods, when significant imports will not be available. It would therefore be rash to design a GB system that cannot occasionally meet demand without them.

Replacing all hydrogen with ammonia would raise the average cost of electricity by some £5/MWh, so adding some ammonia in sites that are remote from areas where hydrogen could be stored would not have a large impact.

Conventional demand management, which shifts demand without removing it, does not affect the need for long-term storage. It could, however, be possible to reduce the need for storage by reducing demand pre-emptively when long periods of very low wind are forecast and storage levels could become low. A first study of this possibility found that reductions of 2.5 per cent (which could be achieved by raising prices and/or invoking contractual obligations) in occasional three-month periods could reduce the required storage capacity by order 10 per cent.[68]

Combining all these measures, and adding baseload generation, the hydrogen and ammonia storage capacity required to meet very long-term storage needs could be reduced to perhaps 40 TWh_{LHV}, but it would be hard to get much lower.

Conclusions

The major conclusions of the Royal Society study are as follows:

- To assess the need for large-scale storage, it is essential to study a long continuous sequence of weather years. Studies that look at individual years, however many, seriously underestimate the need for large-scale storage and overestimate the need for other flexible supply. Whether this is true everywhere needs to be studied region by region, but as Figure 2 shows, it is true in the north-eastern USA and Texas as well as in GB.
- With high levels of wind and solar supported by hydrogen, the 2050 cost of electricity fed into GB's grid will be higher than in the last decade (by 15–100 per cent), but lower than in most of last year and very much lower than in 2022, when the invasion of Ukraine led to very high costs. In other regions that move to high levels of wind and solar supported by storage, the increase in the cost of electricity will depend on the wind and solar resource, and the potentials for storing hydrogen in solution-mined salt caverns and for large-scale hydro.

In order to decarbonize by 2050, construction of wind and solar capacity and work on strengthening the grid should be accelerated, while construction of large-scale electricity storage should begin now. Implementing market mechanisms to attract the required investment will be a necessary precondition. It is hard to envisage the market providing the very long-term large-scale storage that will be needed in GB; governments should consider funding strategic hydrogen and/or ammonia reserves.

The Royal Society report focused on identifying the large-scale storage that will be needed in 2050 in GB. The possible roles of nuclear and gas plus CCS were considered. There is now, however, a need for modelling that also takes account of continuing contributions from burning waste and biomass, hydropower, and interconnectors, as well as the relative locations of supply, storage, and demand, and their implications for the grid. Finally, the need for hydrogen for large-scale electricity storage should be studied together with other uses for green and blue hydrogen, once their scale and their likely temporal variations and flexibility are better understood. This would almost certainly reveal systems benefits that would lower costs.

Acknowledgements

I am very grateful to all those who contributed to the Royal Society study, which I led, who are listed in the report, to Iain Staffell for the data used to construct Figure 2, and to Seamus Garvey, Cameron Hepburn and John Rhys for comments on a draft of this article.

[66] Li, B., Bas, S., Watson, S., Russchenberg, H. (2021), 'A brief climatology of dunkelflaute events over and surrounding the North and Baltic Sea areas', *Energies*, 14, 6508.
[67] Shaner, M., Davis, S., Lewis, N., and Caldeira, K. (2018), 'Geophysical constraints on the reliability of solar and wind power in the United States', *Energy & Environmental Science*, 11, 914–925.
[68] Royal Society Storage Report, supplementary information, p. 169.

LARGE-SCALE ELECTRICITY STORAGE: SOME ECONOMIC ISSUES

John Rhys

The recent Royal Society report on energy storage is an important contribution to understanding both the scale and nature of the energy storage issue.[69] It also raises several significant policy questions for the achievement of a low-carbon economy based on a substantial contribution of renewable energy. These relate both to the future operation of a zero carbon energy economy and to the investment in its infrastructure. This paper sets out some of the most important of these issues, including the balance between markets and central coordination, and the need for a radical reappraisal of the economics of reliability in power systems.

The starting point for analysing the role of energy storage in the context of low or zero carbon economies has to be examination of the scale and nature of the future power system. This includes management of consumer demand, the low or zero carbon technologies for generation, and the quantity of storage that may then be required for adequate levels of reliability.

The recent Royal Society report represents some major steps forward in answering these questions and advancing our thinking. It addresses questions of cost and technology choice for energy storage options. Most significantly, it also analyses demand/supply imbalances, using historical meteorological data to simulate the future performance of high-renewables systems. Evaluated over a long period, 37 years, and assuming plausible patterns of future demand, the model calculates the implicit quantities of storage required for a reliable power system. Simulation makes it possible to explore alternative combinations of low or zero carbon power generation as well as alternative projections of future demand.

Significant indications from the report include the following:

- Across a wide range of cost assumptions, the most efficient (least cost) ways for the UK to attain net zero remain dominated by a combination of wind and solar power, both of which are intrinsically weather dependent. This is despite a very substantial and expensive requirement for long-term energy storage associated with weather-dependent power generation. Although the cost per unit of energy moved in and out of store may be high, this has a much smaller impact on total cost and hence affordability. The value of storage is primarily to ensure long-term reliability, and hence is analogous to that of peaking plants.
- The main determinant of the storage requirement is not necessarily seasonal effects but inter-annual variability – the effect of sequences of years of below average wind output. Surprisingly, this dominates seasonal factors (largely managed by having the right mix of wind and solar) in determining the requirement for long-term storage. Examination of inter-annual variability, and hence a long period of weather data, is therefore essential to assess long-term storage requirements. The Royal Society report stands out, but is not unique, in using meteorological data over an adequately long period.
- The scale of requirement, and the high capital cost per kWh of storage capacity, rule out batteries for long-term storage needs. Grid-operated batteries will remain important for day-to-day or hour-to-hour system control functions, where there is a frequent cycle of charge and discharge. There could be a role for higher cost but more efficient types of store, such as compressed air, which would reduce but not remove the need for long-term storage. But the size of long-term storage need suggests that chemical or other solutions are required as these are intrinsically more likely to have a low capital cost per unit of storage. For the UK the least cost solution for long-term storage is likely to be hydrogen in salt caverns, where the UK has a small number of feasible sites. In other geographies, alternatives such as ammonia may be preferred.
- The crucial importance of storage implies a substantial need for coordination; this includes arrangements for conversion of energy going into store (green hydrogen via electrolysis, or other storage) and for energy coming out of store (as hydrogen to power generation or to a gas grid). This is a necessity in relation both to operation of the overall power and storage system and to choices made at the investment stage.

[69] Large-scale Energy Storage. Royal Society September, 2023. https://royalsociety.org/-/media/policy/projects/large-scale-electricity-storage/Large-scale-electricity-storage-report.pdf

There are, of course, some obvious qualifications and caveats. First, the report is based on meteorological data relevant to UK wind and solar potential, so there is no simple extrapolation to other geographies. However, preliminary indications suggest that similar levels of inter-annual variability will apply in many other temperate regions of the world, including northern Europe, where wind is the dominant renewable technology. Analysis using long runs of meteorological data will be important in most geographies.

Some of the assumptions in the report will remain debatable. For example, the future role of electricity in the residential heat market still has many policy uncertainties, as does the precise contribution of nuclear and the solar/wind balance. Estimates can change on, for example, nuclear or renewable costs. We also do not know how climate change will affect future weather patterns and hence the variability of renewables output.

In spite of these limitations, the general conclusions from the Royal Society simulation models appear quite robust, at least against moderate changes in the underlying assumptions. The findings pose several profound questions for the power sector, particularly about how the necessary investments in storage are to be funded and achieved and how the operation and coordination of future low-carbon systems is to be managed. These are questions of a technical, economic, and policy nature.

The hydrogen market—interactions

Obvious questions, given that the report focuses on hydrogen storage as the most promising candidate for long-term storage, relate to the wider role of hydrogen in the energy economy. Given its importance in industrial uses, sometimes as the only obvious substitute for fossil fuels, and potentially for conversion to synthetic fuels or use in transport or heating, hydrogen is unlikely to be confined to a role as an energy store for the power sector. We can also anticipate at least some international trade in hydrogen.

Consequently, storage held for the power sector cannot be entirely divorced from wider policy and market questions over hydrogen. There will be unavoidable interactions between these wider uses and the specific deployments of hydrogen storage as a central pillar of power sector reliability. Any measure of economic value must reflect the security value of hydrogen held in store, often for very long periods.

It has been suggested that the existence of an extensive and liquid future international market in hydrogen will reduce or eliminate the need for local storage within the UK, and that hydrogen might simply be considered as an internationally traded commodity similar to oil or gas. This is a theoretical possibility but currently seems improbable, or at least unattractive, for several reasons:

- Transporting hydrogen, other than through pipelines, is dependent on compression and liquefaction, which is both energy intensive and expensive. This limits development comparable to oil markets, for example.
- There is an implicit but unproven assumption that, in broad terms, matching of renewables output and consumption might be achieved across relevant regional markets (e.g. Western Europe), on (say) a monthly or quarterly basis.
- Security and energy dependence issues are currently very salient, not least in relation to many geographies which would play a major role.
- We have seen recent price volatility in oil and gas markets. Lack of sufficient storage might imply similar price volatility for hydrogen; the impact of this on consumer prices is an unattractive prospect for governments.

Coordination and markets

Large power systems inevitably pose issues of coordination, and the issue of whether efficiency and reliability can be achieved more effectively through central coordination, or in a more decentralised manner through price signals and market forces alone. Systems that include reliance on renewables and storage introduce additional levels of complexity much less amenable to simple market solutions.

It is important to recognise that there are two distinct time scales here. One is operational—operating a power system as efficiently and reliably as possible in real time with the current mix of assets. The second is about necessary investment—creating the best mix of assets for the future. In the perfect markets hypothesised for the 1990 and subsequent UK market liberalisation, efficient solutions on both time scales were assumed to result from market prices.

The conventional view of a market driven power sector was that price signals set in a competitive market provide the incentives both for the efficient operation of the system and to produce the right mix of assets, generation, networks, and storage for an efficient and affordable future system.

But that simple paradigm already bears less and less resemblance to reality, given the extent and necessity of government intervention in creating and managing capacity markets and guarantees for new investment, not least because carbon pricing is still a long way from reflecting the social cost of emissions. With the prospect of increasing renewables, or nuclear, generation, and the increasing importance of storage, the simplistic market model looks increasingly like a fantasy. There are several reasons for this.

Traditional spot markets were developed to deal with gas and coal powered generation, and to replicate a merit order based on the ranking of short-run marginal costs (SRMC), i.e. fuel, of fossil plant in individual time periods (e.g. half-hour). They do not translate or adapt easily to low carbon technologies with probabilistic features, intermittency, and more complex operating constraints. Storage adds new dimensions, by being intrinsically multi-period, requiring attention to provision and use of conversion capacities (especially for electrolysis), and as a major component of reliability.

Particular examples of coordination requirements not easily handled by markets include the need to optimise the wind/solar mix against seasonal requirements, and to exploit weather diversity in the siting of wind generation. The simple metrics of short-run cost that sit behind conventional market mechanisms do not capture the information or the complexity required for efficient decision making.

Investment choices, on the four-way balances between generation, transmission, storage, and conversion capacity, pose particularly difficult questions, a complexity to which we might add demand management. These have always posed particularly difficult questions for market solutions, accentuated by the observation that renewables typically enjoy zero SRMC, and relate to the issue of how to reward plant that operates at low load factors but is essential to system security. This will also be of particular relevance to the substantial electrolysis capacity which will be required, but only operates when renewable output would otherwise be spilled and wasted.

Infrastructure issues

Hydrogen storage (in the UK) relies on a very small number of potential sites. In addition this kind of storage almost inevitably implies large economies of scale (not least due to the arithmetical observation that volume increases faster than the surface area of a store). The scale of storage required is also very large—equivalent, in terms of energy input for conversion, to several months of current (2023) electricity production/consumption. The realistic prospect of competing storage facilities may be limited, even if we ignore the coordination issues associated with the management of flows in and out of store.

It is evident that long-term storage has all the characteristics that we associate with natural monopoly and large-scale infrastructure. These include major economies of scale, very substantial investment costs, long-lived assets that are highly use specific, and in financial terms, the desirability or necessity for a cost of capital that is as low as possible. For private capital that means a high level of reassurance over future revenue streams and the future market and regulatory environment, for example through a regulated asset base (RAB) approach.

Policy and planning for reliability of supply

But perhaps the least appreciated implication of the analysis is for the way in which we should think about future reliability and security. This is always, ultimately, an economic choice and a trade-off between cost and reliability. Previously this has always been conducted as a debate over adequate margins of generation capacity required over peak demands—typically in relation to so-called needle peaks. But it has been a debate about a unit of power: GW.

The Royal Society analysis indicates that while GW of capacity will remain important, there are equally and perhaps even more important choices—not about GW of generation capacity, but about TWh of energy storage. This is a major distinction. The risks and questions are qualitatively different. Looking at energy rather than power requires the economic and policy calculus to change radically.

Unfortunately, the recent government consultation on storage fails to recognise these issues, focusing on the capacity (generation) for hydrogen to power and ignoring both capacity for input to storage (electrolysis) and the quantity of energy required.

Historically, generation supply reliability in the UK has been about power—kW, and occasional insufficient kW to meet needle peaks. These very infrequent failures to meet demand in full were potentially uncomfortable if they led to consumer disconnections for short periods, but rarely led to more serious problems. For most consumers they were less relevant than local faults in distribution networks. In addition, advances in communications and control systems now make it much easier to avoid system failures by providing different standards of reliability to different types of consumption—prioritising lighting and IT applications over raw heat, for example, or even allowing some consumers to choose different standards of reliability.

The Royal Society analysis implies a different risk. The possibility of a long wind drought, or a run of years of below average wind, implies much longer periods of energy insufficiency, with more far-reaching economic and societal impacts. These may be once in a generation events, like the 1970s three day week, the Covid crisis, or curtailed gas supplies. But they require not just energy supply planning but also attention to the overall energy resilience of the economy.

At the margin there will be alternatives to long term storage. One is the recognition that prices can be used to reduce non-essential energy consumption to some degree, as we can observe from recent experience with gas supplies. Another might be more attention to maintaining strategic reserves of ‘finished product’ to allow temporary curtailment of the most energy intensive industries. But the essential point is that the storage decisions will imply some major policy choices regarding security and reliability.

Conclusions

The report raises some very serious questions:

- a general need to review the roles of markets and central coordination in the context of renewables and storage, with the balance tilting further towards significant degrees of coordination
- addressing the provision of electrolysis capacity for storing surplus
- economies of scale and limited sites lead in the direction of natural monopoly, the treatment of storage as essential infrastructure, and a regulated asset base approach in order to minimise the cost of capital
- re-evaluating policy approaches to understanding and planning for reliable future systems; the role of a TWh energy reserve raises qualitatively different issues from that of a capacity or power reserve.

Balancing central intervention against markets should start with identification of essential decisions for the power system where an unfettered market cannot be relied on to produce efficient or acceptable outcomes. These include definition and setting of security and reliability criteria, finding complementary combinations of low carbon generation, identification of natural monopoly, some operational choices, and resolution of issues in the electrolysis market. Remedies can then be found through clear assignment of the coordination responsibilities involved, whether through direct control or in the design and conduct of various capacity markets. The key parties include government and regulatory bodies on policy choices, and systems operators in guiding investment and ensuring reliable and efficient operation.

The Royal Society report provides some indications of where the answers to these closely inter-related questions may be found, including novel market mechanisms and incentives to reward storage and conversion capacity, long-term contractual assurance for infrastructure providers, and centrally driven coordination of investment plans and an enhanced role for the future systems operator.

MULTI-ENERGY SYSTEMS AND STORAGE: THE NEED FOR EFFECTIVE PROJECTION OF FUTURE POWER SYSTEM NEEDS

Paul Plessiez, Florent Xavier, and Patrick Panciatici

The transition to a carbon-neutral Europe by 2050[70] will impose profound changes in energy systems: deeper electrification and digitalization, integration of offshore wind farms, and more generally further renewable energy integration, emergence of a hydrogen and green gas economy including flexibility capabilities and CO_2 management, climatic resilience, and societal impact, while ensuring energy affordability and security of supply.

Europe has set forth the ambition to be the world leader in renewable energy, as is clear from the European Green Deal. In combination with an expected increased stress due to climate change, the energy system and its operation is expected to become more weather dependent, subject to unexpected long- and short-term variations, and relying on decentralized renewable energy sources (RES). To reach the Green Deal targets, more integration of renewable energy across sectors and vectors is needed. While electrification will assist in decarbonizing the economy, converting to other energy carriers such as gases and heat will make it possible to enable storage across different vectors and to provide flexibility in a reliable and cost-effective manner. Furthermore, indirect electrification, for example through conversion to hydrogen and power-to-X fuels, is needed for deep decarbonization in some sectors (e.g. heavy transport) to reach the net-zero target.

The future of electricity in France

RTE, the French transmission system operator, released last September the 2023 *Outlook*,[71] a detailed analysis of the prospective vision of the French power system. It covers the period 2023–2035, which is characterized by an acceleration of ambitions in terms of decarbonization and industrial revitalization.

The 2023 *Outlook* examines the challenges of shifting from fossil fuels to electricity, which is a necessity for decarbonizing France and enhancing its energy sovereignty. New perspectives are leading to an increased role for electricity in France's medium-term energy mix. The European-level objective is necessitating an accelerated shift from fossil fuels to low-carbon energies, particularly towards electricity. Concurrently, France is pursuing a second strategic objective: to enhance the country's energy and industrial sovereignty through reindustrialization.

In the medium term (2030–2035), to achieve climate and sovereignty ambitions, it is not feasible to phase out nuclear power without a significant acceleration of renewable energies. From the technical, economic, and industrial perspectives, the challenge is to operate an electrical system based on a growing share of renewable energies and incorporating new uses of electricity (in transportation, buildings, and industry).

Four key levers are identified to address these challenges and meet public objectives: increasing energy efficiency, reducing energy demand ('*sobriété*'), maintaining adequate availability in the existing nuclear fleet, and expanding renewable energy.

The current approach to supply-demand balance flexibility

The evolution of the electrical system requires mobilizing different flexibility solutions to meet various needs—structural and regular flexibilities to smooth expected cyclic variations in production or consumption, from annual to hourly time frames, and dynamic flexibilities to adapt to stochastic variations. These flexibilities are usually valued on the electricity markets at different time horizons and using different mechanisms:

- ancillary services providing dynamic flexibility to adapt to stochastic variations,
- balancing mechanisms to ensure that supply and demand are balanced in expectation (market participants behave fairly and make unbiased forecasts) and that the reserves required for ancillary services are committed,
- day-ahead and intra-day markets.

The French market design is based on the concept of balance responsible party.[72] Each such party must balance its portfolio and is responsible to own or to buy enough capacity and flexibilities. For long-term balancing, this requires a significant provision of assets.

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[70] Intergovernmental Panel on Climate Change (2018), *Global Warming of 1.5°C*, www.ipcc.ch/sr15/.
[71] RTE (2023), *Bilan Prévisionnel 2023–2035*, www.rte-france.com/actualites/bilan-previsionnel-transformation-systeme-electrique-2023-2035.
[72] RTE (2024), *Becoming a balance responsible party*, www.services-rte.com/en/learn-more-about-our-services/becoming-a-balance-responsible-party.html.

In addition to these normal balancing issues, some conditions may require additional services, in particular for congestion management or large generation losses, to avoid load shedding and possible blackouts: backup flexibilities (post-market products, load management of industrial customers), and network flexibilities.

This article does not address the issues of congestion management and the need for network flexibilities, although balancing and congestion management are becoming increasingly intertwined.

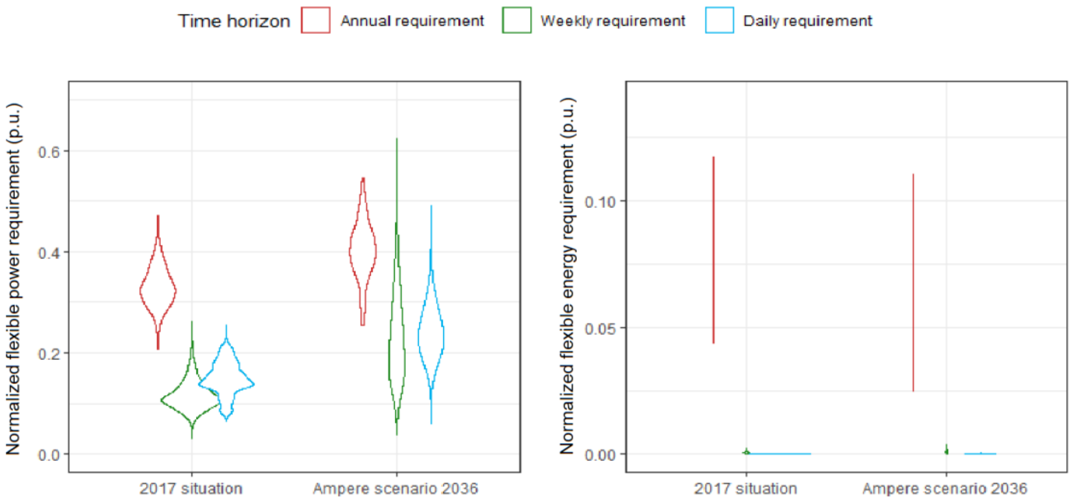
An increasing need for flexibilities

In the coming years, other forms of flexibility will need to be developed in addition to low-carbon production units. The RTE *Outlook* provides a detailed analysis of flexibility needs in different scenarios and variations. These flexibility needs cannot be simply summarized as a gigawatt value; they must consider various characteristics in managing the electrical supply-demand balance.

For example, by replacing synchronous rotating machines in the generation mix, RES reduce the inertia of the power system, increasing the need for short-term, frequency-stabilizing flexibilities. The consideration of the production patterns of RES also highlights the time scales at which flexibility is needed: in northern Europe, solar power increases the need for annual flexibility due to its annual pattern in opposition with the consumption pattern, whereas wind power increases the need for daily flexibility.

Consequently, when considering flexibility needs, it is essential to consider the time scale at which these flexibilities can accommodate imbalances, as the modulation need is composed of several patterns which have different frequencies. For example, Figure 1 illustrates the different needs for annual, weekly, and daily power and energy flexibilities in the French electricity system.

Figure 1: Flexibility requirements evaluated in 2017 and projected for 2036 in RTE's Ampere scenario



Source: Heggarty, T. (2021), Techno-economic optimisation of the mix of power system flexibility solutions, Electric power, Université Paris, Sciences et Lettres, https://theses.fr/2021UPSLM030.

Note: The Ampere scenario was defined in the RTE 2017 Outlook[73] (up to 2035), in which the share of nuclear in the mix was lower, but carbon-based thermal generation was the same.

The RTE *Outlook* considers developing demand-side flexibility and batteries a priority, with the potential to gain around 5 GW of margin. Other needs ('long flexibility') are also emerging, leading to the study of several flexibility portfolios to meet electricity needs at all time scales.

Current solutions and their limits

Several solutions are available to help meet different flexibility needs: demand flexibility (load reduction and load modulation), stationary batteries, thermal power units, and hydropower plants including pump-storage stations. These solutions have their own characteristics and constraints (storing or moving energy, availability, fixed and variable costs, etc.) and may be more or

[73] RTE (2017), *Bilan Prévisionnel edition 2017*, https://assets.rte-france.com/prod/public/2020-06/bp2017_synthese_17.pdf.

less suitable for certain needs. This list is not exhaustive, and other solutions may emerge in the near future (e.g. heat storage and H_2 storage) but currently have questionable business models and/or feasibility or reliability issues.

The current flexibility system in Europe is primarily composed of fossil fuel power plants, hydropower plants, and French nuclear power plants. Additionally, flexibility in consumption through industrial load reduction or scheduling hot water heater recharging during off-peak hours also contributes to maintaining supply-demand balance.

Among these various flexibility sources, thermal power plants are expected to close for ecological reasons, the potential for hydropower development is limited in France, and French nuclear power is subject to the imperative of improving its availability rate. This rate has been reduced over the past decade due to the significant maintenance work and component changes necessary to ensure the extension of reactor operating life. Nuclear power plants in France offer more flexibility than those in other countries. However, this flexibility is limited due to technical constraints, which become of increasing importance as plants age. These constraints require complex modelling with temporal coupling constraints. For instance, the flexibility potential is limited when reaching the end of the availability period before a refuelling maintenance.

Hydropower plants offer flexibilities at different time scales. However, due to the effects of climate change, including drought and less snow in winter, conflicting objectives arise regarding water usage for irrigation, tourism, and other purposes.

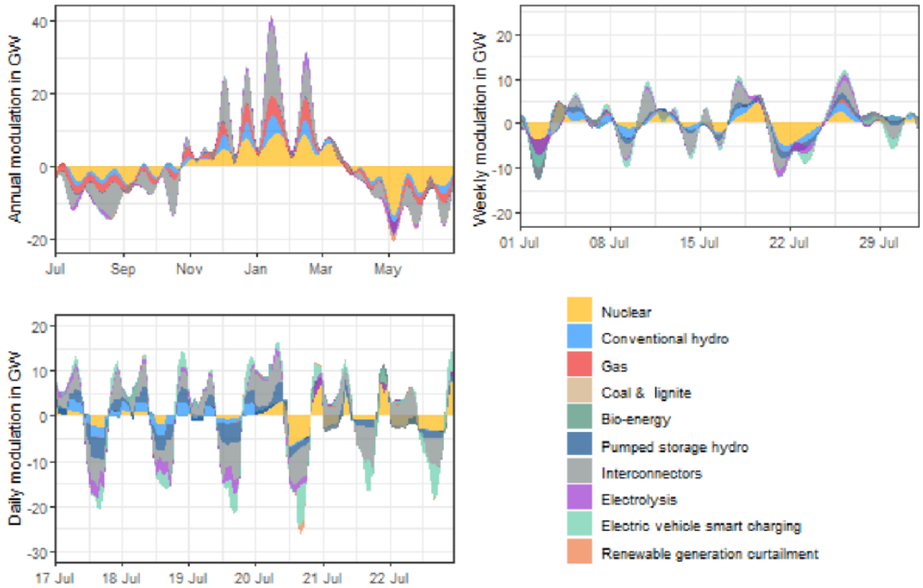
The interconnections between European countries are currently also an important way to share flexibility needs and provisions. However, RTE's 2017 Generation Adequacy Report shows that, by 2035, the perfect interconnection of European countries would only cover a theoretical maximum of around 30 per cent of the flexibility requirements for forecast balancing.

Emerging flexibility opportunities

After load modulation, battery storage constitutes the second resource expected to play an increasingly significant role in the flexibility of the electrical system. RTE's analyses confirm the insights from the RTE report *Energy Pathway 2050*[74], particularly the role of storage in scenarios with accelerated development of photovoltaic energies and limited development of consumption flexibility.

The electrification of all energy sectors is expected to increase sector coupling and create additional demand flexibility opportunities, particularly related to power-to-X conversion. *Energy Pathways 2050* projects that the share of flexible consumption will increase significantly from 4 per cent to 15 per cent by 2050. Current and emerging flexibility solutions could help meet flexibility needs at various time scales, as illustrated in Figure 2.

Figure 2: Annual, weekly, and daily flexibility solution modulation stacks for a prospective 2035 French power system



Source: Heggarty, T. (2021), Techno-economic optimisation of the mix of power system flexibility solutions, Electric power, Université Paris, Sciences et Lettres, https://theses.fr/2021UPSLM030.Challenges for long-term energy system planning

[74] RTE (2021), *Energy Pathways to 2050*, https://assets.rte-france.com/prod/public/2022-01/Energy%20pathways%202050_Key%20results.pdf

Modelling and studying multi-energy systems

RTE has developed and is using software called ANTARES (antares-simulator.org) to simulate large, interconnected power grids and capture long- and short-term uncertainties. ANTARES is a Monte Carlo probabilistic simulator designed for long-term studies. It simulates the economic behaviour of the entire electricity system under perfect market assumptions, with a resolution of one hour over the year. This is an advanced tool, but the energy transition is pushing to improve various aspects.

The key to achieving zero greenhouse gas emissions in all energy sectors by 2050 is to reduce final energy consumption while increasing the share of electricity based on carbon-free energy sources in the energy mix. As the infeed of photovoltaic and wind power is highly variable and uncontrollable, linking energy systems will enhance the storage capability and flexibility of the whole system. This requires an integrated consideration of all energy vectors and coordinated infrastructure planning across all of them.

Producing accurate operational expenditure estimates and assessing risks of energy shortages and renewable energy curtailment calls for precise system operation simulations. Identifying essential reliability levels and related criteria and evaluating them pose significant difficulties when determining the necessary level of flexibility. Optimization processes must address both average outcomes and tail-based phenomena for which risk mitigation is needed, from probability distributions.

However, simulating the operation of an energy system becomes complex when dealing with larger, interconnected multi-energy networks, particularly given their growing uncertainty and volatility. Consequently, cutting-edge optimization and simulation approaches require further investigation to effectively solve long-term energy planning issues. One such endeavour is the MUESSLI project (MUlti-Energy System Smart-Linking Integration, https://cresym.eu/muessli/), in which RTE is involved within the CRESYM (Collaborative Research for Energy SYstem Modelling) research association, focusing on developing innovative tool coupling methods and architectures to tackle system planning and simulation case studies.

Uncertainties about the flexibility provided by sector coupling

Another major uncertainty relates to the flexibility associated with the development of hydrogen. In Europe, a consensus has emerged in recent years on the importance of hydrogen for the decarbonization of hard-to-electrify sectors (heavy-duty transportation, steel production, ammonia production, etc.). Beyond this apparent consensus, there are significant differences in vision. Local hydrogen systems (e.g. around industrial basins) coexist with the idea of a global system for long-distance exchange of hydrogen and synthetic fuels. In Europe, countries such as Germany are arguing strongly for the latter option, speaking of defossilization rather than decarbonization, with CO_2 capture and synthetic fuels in mind.

The uncertainty is even greater when it comes to providing the flexibility needed to manage the electrical system. In a context where hydrogen production is expected to expand significantly over the next decade, the modulation capabilities of the electrolyser and the storage of hydrogen will play a crucial role in the electricity supply/demand balance. Electrolysers are assumed to be flexible and able to modulate, but this will only be possible if the electrolyser technologies used are truly flexible, and if the industrial processes they serve are themselves flexible (which is not the case for most industries), or if they are connected to very large hydrogen storage capacities (which do not currently exist and do not meet current safety regulations). Long-term storage of hydrogen also appears to be very challenging[75] , but would be an interesting option to cope with the seasonal variations of RES.

Uncertainty also exists about the future energy market's structure and outcomes. Many market elements are related to political decisions (market mechanisms for energy and reserve provision, taxes and subsidies, etc.), which cannot be anticipated by the sole use of techno-economic analysis. As a result, even though operational simulation and investment planning on prospective systems provide marginal energy prices (which are results of the optimization), these are not a perfect prediction of what future prices will be as they don't consider these exogenous parameters.

A better and shared understanding of the technical constraints and associated costs of multi-energy systems is then necessary. To improve the modelling of the new assets of future multi-energy systems (energy conversion devices, storage systems, electric vehicles, etc.), RTE has initiated a collaboration project called PlaneTerr (Expansion Planning and Energy Coupling in

[75] Portarapillo, M and Di Benedetto, A. (2021) Risk Assessment of the Large-Scale Hydrogen Storage in Salt Caverns *Energies* 2021, *14*(10), 2856; https://doi.org/10.3390/en14102856

Local Areas, https://planeterr.fr/), involving major industrial actors (Total Energies, Air Liquide), utilities (RTE, GRTgaz), and an academic partner (Mines Paris PSL). The purpose of the project is to improve the modelling of novel energy system components for energy system simulation and planning studies by testing on physical demonstrators, and to study the potential contribution of these new assets to meeting the flexibility requirements of prospective systems.

Managing the modelling of long-term energy storage systems

Sector coupling should allow long-term storage (several days or weeks) and could become increasingly important in the operation of multi-energy systems. Indeed, synthetic methane, hydrogen, and ammonia could potentially be stored to meet energy demand throughout the year, even if the conversion back to electricity (power-to-X-to-power) has very low overall efficiency. These assets must therefore be correctly modelled in prospective study tools. For instance, considering the long-term and short-term uncertainties brought by an increasing share of RES, assuming perfect foresight over a year in the management of these systems would be too optimistic and would underestimate the actual need for flexibility to tackle these uncertainties. The management of long-term storage systems must therefore be correctly modelled, considering an imperfect knowledge of the future and associated risk management policies, to correctly estimate the associated flexibility requirements. Work relying on stochastic optimization and dynamic programming is performed to design and implement these policies in prospective study tools.

Market design: how to price flexibilities?

The current electricity market was not designed to manage massive amounts of renewable energy, the production of which depends on meteorological conditions and not on price. It is obvious that sunshine and wind speed do not depend on market price. For these RES, the marginal cost of production is close to zero; the primary energy is free. Changing the price does not impact their production but only their revenues. This could have an impact on investment in RES technologies in the medium term but does not affect the participation of existing RES in balancing the system. Some other means are essential to balance the system. We must remember that conventional generation units—nuclear, thermal, and hydro with some form of energy storage—are price sensitive and have varying degrees of flexibility.

Well-designed and organized day-ahead and intra-day markets should give the right signals to market participants to ensure system balance. To carry out an activity in the French electricity market (production, consumption, sale, purchase, import, export), it is necessary to designate or become a balance responsible party. This party must physically balance its portfolio (sum of supplies equal to sum of demands), whatever the commercial contacts involved: OTC (Over The Counter), PPA (Power Purchase Agreement), offers on the organized day-ahead/intra-day markets and balancing mechanisms. This should encourage market participants to have access to sufficient flexible supply and flexible demand, including storage based, by owning flexible assets or buying flexible contacts.

It is important to recognize two different storage needs: time shifting energy to meet demand at a lower cost ('energy banks'), and ancillary services to maintain system stability, power quality, and reliability ('shock absorbers').[76]

The first need relates to expected demand forecasts, and market participants are responsible for balancing their portfolios in expectation (unbiased behaviour), but forecast errors and unplanned outages do occur. Maximizing social welfare requires managing the impact of all these unexpected (in the statistical sense of the term) events through a common pot. This minimizes the total amount of reserves required, thanks to the smoothing effect of the sum of uncorrelated events (random variables).

The second requirement relates to the management of unavoidable random effects through what are commonly called ancillary services. The nature and quantity of these services are affected by the massive integration of RES. We must remember that these services are mandatory to ensure system stability, power quality, and reliability.

Reliable provision of these services is essential. Transmission system operators and independent system operators are responsible for ensuring a well-functioning system in real time (in accordance with defined reliability requirements), activating these ancillary services, and avoiding as much as possible the use of emergency measures (such as load shedding and generation curtailment) while keeping the cost of ancillary services as low as possible.

[76] Inspired by Mark Thurber, M. (2024), 'Better battery strategy in emerging markets', energyforgrowth.org/article/better-battery-strategy-in-emerging-markets-or-why-you-shouldnt-put-all-your-eggs-in-one-bess-kit/).

Transmission system operators and independent system operators need to define the nature and quantity of these ancillary services and the mechanisms for activating them. Pricing of ancillary services is challenging. Recovering the associated costs and allocating them to network users is even more challenging, especially when many different ‘products’ are defined. Indeed, the many different ‘products’ are generally not independent and are also technology dependent (for example, an electric battery and a pumped hydro storage power station cannot provide the same type and amount of service.). RTE aims to remain neutral towards different technological solutions by prioritizing flexibility requirements for ancillary services over specific solutions. To encourage innovation, RTE participates in demonstration projects and conducts public consultations.

Flexibility needs will vary from country to country, and interconnections should not be seen as a perfect flexibility solution, as it is possible that when there is not much wind in the Netherlands, there may not be much wind in Belgium or France. But interconnections should still help to limit the need for flexibility contracts.

New rules will therefore have to be found for a common dimensioning of reserves, or even an exchange of reserves, which would limit the amount to be contracted.

Conclusion

Recent prospective studies have projected that, as energy systems become more decarbonized and interlinked in the coming years, there will be an increasing need for flexibility at all time scales to cope with unforeseen variations in production and consumption and to ensure adequacy of supply in line with reliability standards. Flexibility provision needs to be built based on current solutions (hydro power, nuclear plants, strong interconnections with neighbouring countries), but must also consider the novel flexibility opportunities brought by new energy uses, like batteries, sector coupling, or electric vehicle smart charging.

However, the study of multi-energy, highly variable energy systems, poses significant challenges in terms of modelling and simulation, on long-term uncertainties on the actual flexibility that these new sources will be able to provide and on how future market designs will provide incentives to use these flexibility opportunities, for both energy time shifts and ancillary services. Utilities also need to be able to correctly project future flexibility needs to appropriately size the associated products on these markets.

These challenges pinpoint the need for increased collaboration between utilities, industrial partners, and academics, to improve the way flexibilities are considered in system planning studies and provide insights to support a successful transition to a carbon-neutral energy system.

HYDROGEN STORAGE FOR DECARBONIZED ELECTRICITY MARKETS

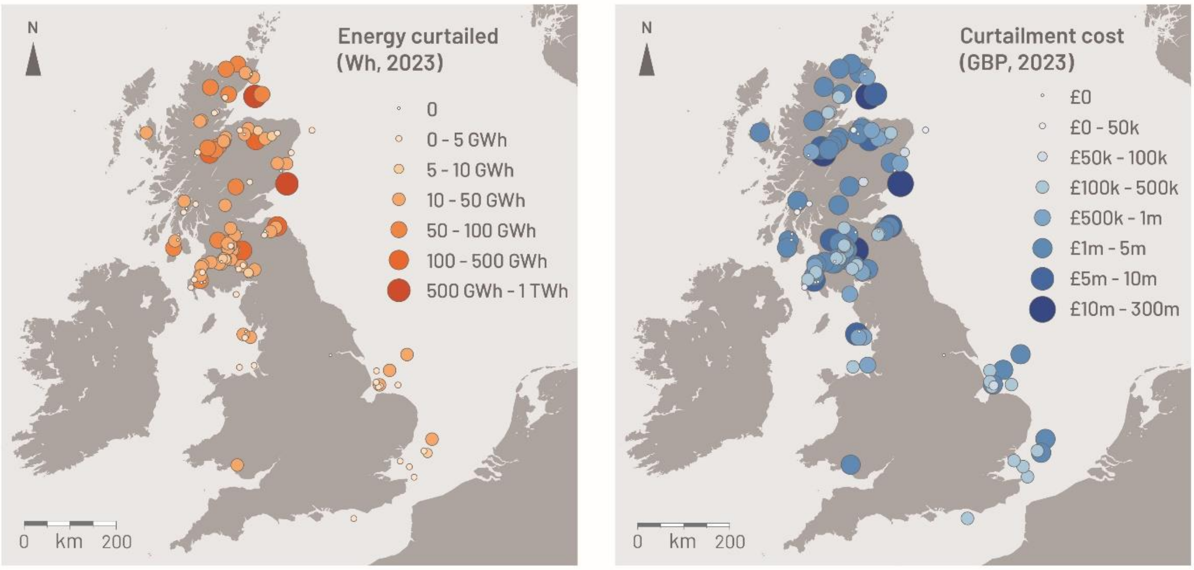
Katriona Edlmann

The shift towards variable renewable energy sources such as wind and solar, to achieve decarbonization in support of the UK Sixth Carbon Budget and emission reduction targets, has highlighted the critical role of energy storage in ensuring reliability and stability for a decarbonized electricity market. Geological hydrogen storage is particularly well suited to providing the necessary large-scale, long-duration energy storage for peak demand and seasonal energy balancing. It can also provide security of supply to hydrogen off-takers, security of demand to hydrogen producers, and the optimization of hydrogen production capacity requirements.

The role of hydrogen in seasonal energy storage

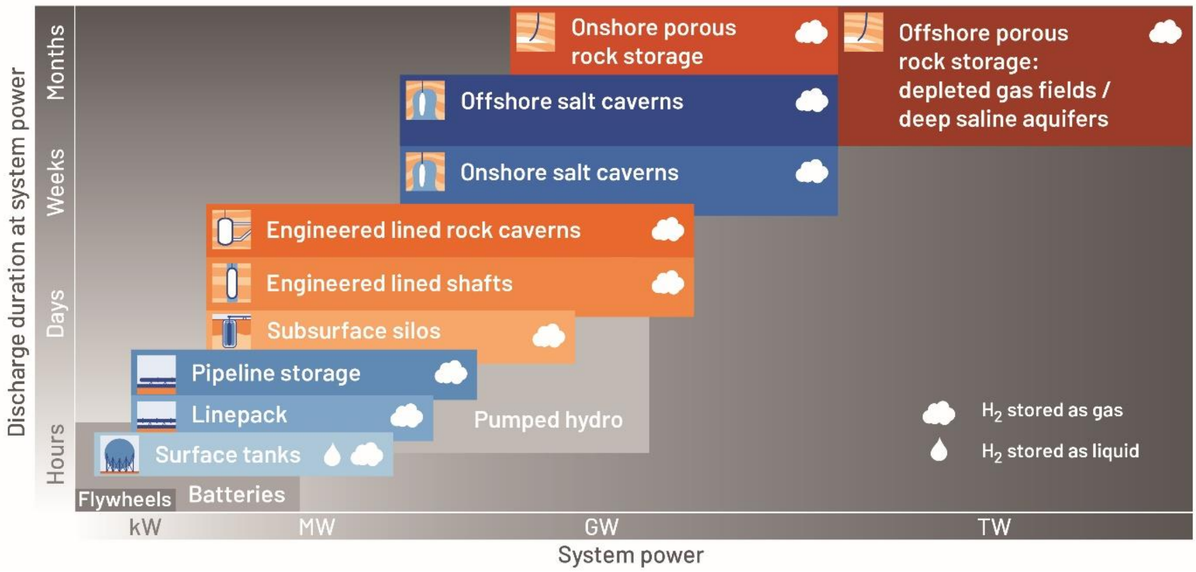
The electricity markets are facing significant challenges associated with increased inputs of distributed variable renewable electricity and increased demand through increased electrification—all managed through an aging electricity grid, putting the reliability and stability of the grid at risk. This is reflected by the continued increase in the curtailment of renewable energy, estimated at 4 TWh in 2023, up from 1.9 TWh in 2019 (Figure 1). As we move towards a renewable-dominated energy system, the UK National Grid Future Energy Scenarios anticipate an inter-seasonal hydrogen energy storage requirement of between 12 and 56 TWh/year by 2050 across all net-zero scenarios.

Figure 1: UK curtailed wind in 2021



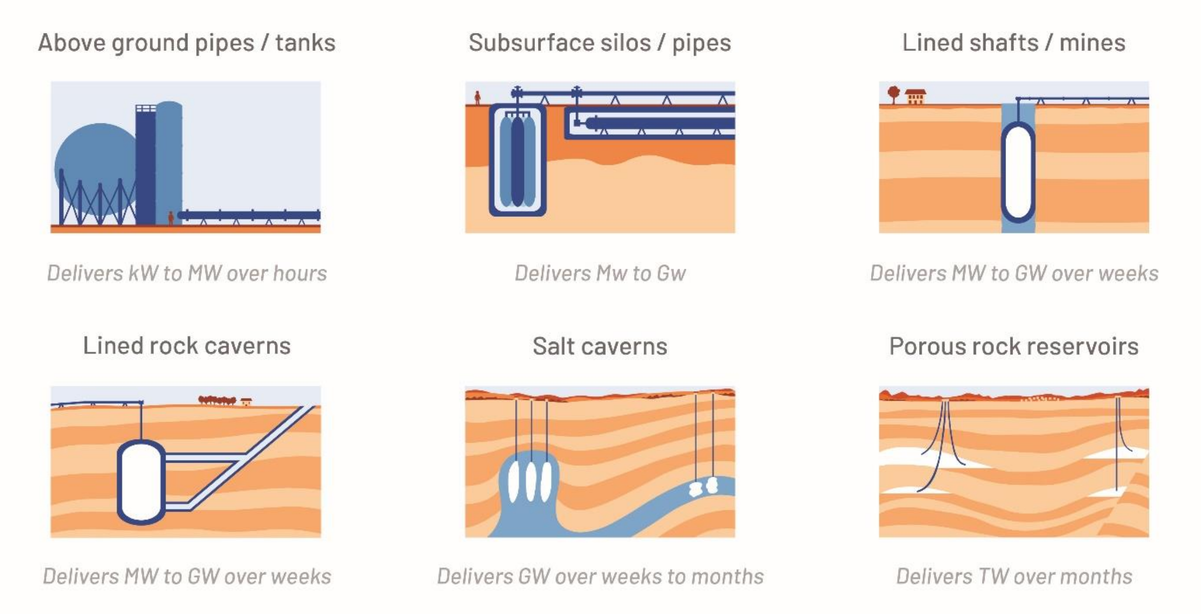
Of the existing energy storage technologies, flywheels (Figure 2, lower left) can deliver kWh with an almost instant response, making them ideal for applications requiring fast frequency regulation and short-term stability. Batteries can deliver a few kWh to hundreds of MWh, with rapid response making them suitable for frequency regulation, peak shaving, and providing backup power. Pumped hydro storage can deliver several GWh, providing energy for several hours to days. Thermal energy storage can store heat or cold for hours or days and is useful for shifting heating and cooling energy use from peak to off-peak times. Only the storage of hydrogen gas in suitable geological formations can deliver the required TWh capacity of energy storage with delivery over weeks to months that will be necessary for a renewable-heavy grid.

Figure 2: Discharge duration and system power for different energy storage technologies



A range of geological hydrogen storage technologies are available with different capacities, operational flexibility, and locational constraints (Figure 3). Dedicated hydrogen pipelines and subsurface silos (pods of high-pressure cannisters housed in cemented boreholes) can provide kW to GW storage capacity, under constant delivery, and can be deployed in most geographical locations. Lined rock caverns and shafts, excavated out of intact rock around 100 m deep and lined with cement and steel, can provide MW to GW storage capacity, with delivery over weeks, and can be deployed in most geographical locations. Salt caverns, solution mined from deep deposits of salt, can provide GW storage capacity, with delivery over weeks to months. UK salt deposits are geographically restricted so will require connecting transport infrastructure. Porous rock storage, including depleted gas fields or deep saline aquifers, can provide TW storage capacity, with delivery over months, and will also require connecting transport infrastructure.

Figure 3: Geological hydrogen storage technologies



There is a proven track record of storing hydrogen in geological formations, demonstrating its technical and commercial feasibility. Historically, this included storing town gas (~60 per cent hydrogen) in porous aquifers for decades, and 100 per cent hydrogen has been stored in three salt caverns in the UK since the 1970s for use in the chemical industry. The Swedish Hybrit project, for decarbonized steel manufacturing, has begun gas tightness testing with hydrogen in a lined rock cavern.

Technical challenges and economics

The technical challenges facing the nascent hydrogen energy storage industry include the high cost of hydrogen production, efficiency losses during power-to-gas-to-power conversion (estimated at 18–46 per cent[77]), and the development of hydrogen transport and storage infrastructure.

Over 95 per cent of global hydrogen production is from methane reformation or coal gasification (grey hydrogen) with unabated CO_2 emissions (9 to 12 kg_{CO2}/kg_{H2}) at £0.80 and £2.40 per kg_{H2}, dependent on natural gas prices. The UK produces 1,929 Million tonnes/day of grey hydrogen across 31 sites. The CO_2 emissions can be captured and stored in deep geological formations (blue hydrogen) at £1.60–3.20/kg_{H2}, depending on the efficiency of the carbon capture and storage process and the cost of natural gas. HyNet, East Cost Cluster, and Acorn are in planning as part of the UK carbon capture, utilization, and storage–enabled hydrogen production projects and are expected to contribute 4 GW to the 2030 10 GW UK low-carbon hydrogen production capacity target.

Green hydrogen produced via electrolysis of water using renewable energy has no emissions at £2.40–4.70/kg_{H2}. The UK produces 2.21 Million tonnes/day of green hydrogen from 14 sites. That is set to increase as 17 projects totalling 262 MW of capacity have been shortlisted in the first Electrolytic Hydrogen Allocations Round, with a second round just launched, aiming to allocate up to 875 MW of hydrogen production capacity. By 2035, green hydrogen is expected to be cost-competitive with fossil fuels, driven by declining renewable energy costs, technical improvements, and economies of scale in electrolyser production. The absence of a mechanism for using curtailed wind for hydrogen production is expected to be addressed by the UK government’s Review of Electricity Market Arrangements consultation, potentially facilitating a cost-effective green hydrogen production pathway.

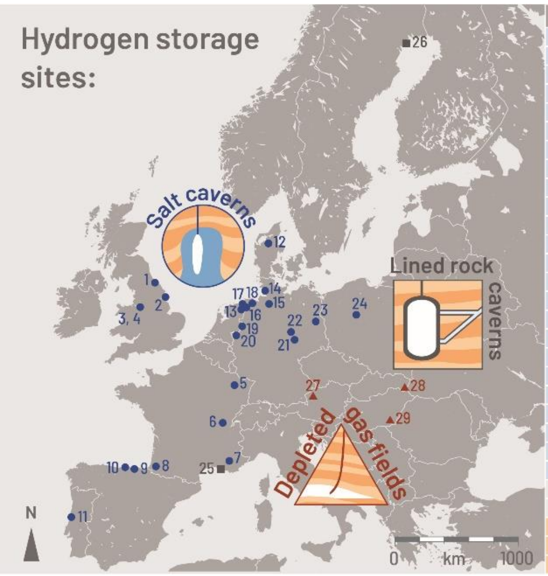
[77] https://www.nature.com/articles/s41467-022-29520-0.

Hydrogen pipelines can transport energy more efficiently and cost-effectively than electricity transmission lines, offering 10 times the energy transport at one-eighth the cost. The European Hydrogen Backbone and the UK Project Union are working to create an extensive hydrogen pipeline infrastructure from repurposed and new pipelines, connecting hydrogen production and storage sites with key industrial clusters and demand centres across Europe and the UK.

There is significant uncertainty surrounding hydrogen storage infrastructure costs. Current estimates suggest that pressurized containers have the lowest cost of storage per kg at £0.15–0.90/kg_{H2}; however, these have an extremely small capacity. For geological storage, the cost per kg is estimated at £1.50–2.25/kg_{H2} for depleted gas fields, £0.20–0.75/kg_{H2} for salt caverns, and £0.55–3.00/kg_{H2} for lined rock caverns. For comparison, the estimated costs for chemical storage are £1.10–3.00/kg for ammonia, £3.60–5.80/kg for liquid organic hydrogen carriers, and £3.60–5.30/kg for liquid hydrogen.

Geological storage of hydrogen will be the most cost-effective option to deliver the necessary seasonal storage in the electricity market. Until we have pilot sites it will be impossible to determine the true cost of underground hydrogen storage. Currently, several pilot hydrogen storage projects are underway in Europe (Figure 4), including two planned in the UK under the Hydrogen Storage Business Model.

Figure 4: Geological hydrogen storage projects in planning across the UK and EU



#	Name	Company	Capacity (TWh)	Start date
1	Teesside	Sabic	0.027	1972
2	Aldbrough Hydrogen Pathfinder & Storage	SSE Thermal Equinor	0.02 & 0.32	2025, '28
3	HyNet NW Keuper Gas Storage	Inovyn	1.38	2025
4	Hysecure	Inovyn & Storegy	0.04	TBD
5	Cerville	Storengy	TBD	2028 (est.)
6	HyPSTER	Storengy	0.002	2023
7	GeoH2	Storengy	0.24	2028
8	HyGeo & HySow	Terega	0.002 & 0.5	2024, '30
9	H2 Storage North-2	Enagas	0.24	2029
10	H2 Storage North-1	Enagas	0.335	2029
11	Carrico	REN	0.20 (est.)	2025
12	Green Hydrogen Hub Denmark	Gas Storage Denmark	0.25	2025
13	Hystock	Gasunie	0.24	2028
14	Westküste 100	Raffinerie Heide	0.003	2023
15	SaltHy	Storengy	0.205	2030
16	Astora H2 Jemgum site	Astora H2 (SEFE)	0.5	2030
17	Salt Cavern Krummhörn	Uniper	0.0006	2024
18	H2CAST Etzel	StoragEtzel	2.3	2024
19	Get H2	RWE	0.13	2029
20	H2 Storage Xanten	RWE	0.14	2030
21	Bad Lauchstädt Energy Park	VNG Gasspeicher	TBD	2026
22	H2 Storage Staßfurt	RWE	0.21	2030
23	HyCAVmobil	EWE	0.0002	2023
24	UGS Damasawek	GAZ System	TBD	2030
25	GEOGAZ H2	Geostock	0.04	2028
26	HYBRIT	SSAB	0.0004	2022
27	Underground Sun Storage	RAG	0.004, 0.52	2023, '30
28	UGS Velke Kapusany	NAFTA	0.01 (est.)	2025
29	Aquamarine	MFGT	0.01	2023

Policy and regulatory frameworks for hydrogen storage

In August 2021, the UK government published the UK Hydrogen Strategy. The invasion of Ukraine and resulting energy crisis resulted in the British Energy Security Strategy in April 2022, which emphasized the importance of hydrogen storage in providing increased energy security. Support mechanisms at the time, including the Net Zero Hydrogen Fund and the Hydrogen Production Business Model, were deemed insufficient for encouraging investment in storage. To address this, the Hydrogen Storage Business Model (HSBM) and the Hydrogen Transport Business Model (HTBM) were developed. The business models are designed to support the development of a market for hydrogen storage, ensure security of supply for off-takers, mitigate the risks developers face, and provide better certainty to investors to encourage final investment decisions to be taken. The initial ambition for the first allocation round of the business models is to support up to two storage projects and associated regional pipeline infrastructure, to be in operation or under construction by 2030.

In August 2023, the UK government indicated its 'minded to' position for the HTBM to operate on a regulated-asset-base model, supplemented by an external subsidy mechanism to work in conjunction with the regulated asset base. For the HSBM, the approach will involve private law contracts to create the business model, which will offer a revenue floor to ensure baseline profitability and mitigate demand risk, whilst providing a sales incentive on storage services. The government also considers taking equity stakes in facilities. The HSBM will initially focus on supporting geological storage but will keep the option open to support above-ground storage in certain instances. There is a requirement for collaboration between applicants for the HSBM and the HTBM as part of a transport and storage cohort assessment process to ensure that transport and storage projects align.

The current proposed timeline of the HTBM and HSBM is that the application window will open in Q3 2024, with successful projects announced in Q4 2025. The eligibility criteria for the HSBM require a new build or converted mothballed geological gas storage facility, engagement with permissions to use the area, a strategy for receiving planning and social permissions, a commercial operating window of 2028–2032, deployment of a geological storage technology with a technology readiness level (TRL) of 7 or above to ensure projects are commercially deployable, a minimum energy value of 50 GWh (higher heating value) of working gas, evidence of private investment, and evidence that the facility is open for access by third parties. The assessment criteria are based on ability to commission, construct, and operate the facility (deliverability), the commercial case, the cost per unit capacity, and the economic benefits (at the local, regional, and UK levels).

The government will work closely with the Office of Gas and Electricity Markets (Ofgem) and industry to provide early strategic direction for the build-out of hydrogen transport and storage infrastructure. Longer term, the position is that the national energy system operator (formerly the future system operator) should take on a central strategic planning role from 2026, within the statutory framework provided by the Energy Act 2023. This establishes a new, publicly owned national energy system operator that will hold key roles for electricity and gas networks, taking a whole-energy-system approach when operating, planning, and developing these networks.

Planning and permitting regimes for hydrogen storage

Hydrogen is defined as a gas under the Gas Act 1986, which is regulated by the Gas and Electricity Markets Authority, operating through Ofgem. This requires anyone involved in hydrogen operations to hold a license. Consent is needed under the Planning (Hazardous Substances) Regulations 2015 to store 2 tonnes or more of hydrogen. Major hydrogen storage and transport projects may be considered nationally significant infrastructure projects, necessitating a development consent order under the Planning Act 2008. However, smaller projects or pipelines may be regulated under the Town and Country Planning Act 1990. An environmental impact assessment will be necessary if hydrogen is stored on-site or transported via pipelines, as per the Town and Country Planning (Environmental Impact Assessment) Regulations 2017. In addition, several health and safety laws apply to hydrogen activities, including the Planning (Hazardous Substances) Act 1990 and the Dangerous Substances and Explosive Atmosphere Regulations 2002.

The UK's nascent hydrogen storage industry will utilize existing oil and gas storage regulatory, planning, and permitting regimes for the first-of-a-kind projects, with the recognition that hydrogen-specific standards and guidance will be required for next-of-a-kind projects. The UK Government Hydrogen Planning Barriers research project identified that the key barriers in planning can be divided into 'systemic' barriers, which affect hydrogen projects due to broader issues in the UK's planning system, and 'procedural' barriers directly related to hydrogen projects.[78]

Key barriers in the UK's planning process for hydrogen projects are identified as a critical shortage of resources within local authority planning departments and other statutory consultees; a general lack of experience with hydrogen across local authorities, statutory consultees, and developers; public resistance to development, particularly concerning hydrogen projects; difficulties in coordinating between stakeholders such as regulators, local authorities, and community groups; an absence of clear, hydrogen-specific planning guidance; challenges associated with planning thresholds and regulations; a rigid planning process; and discrepancies in planning approaches across different UK nations. To address these issues, it is suggested that a central support hub be established within The Department of Energy Security and Net Zero (DESNZ), complemented by the development of a toolkit to facilitate pre-application discussions and the creation of informal forums for knowledge sharing and collaboration.

Implications of the Hydrogen Storage Business Model for the future of hydrogen storage

In the first-round applications, the storage technology must be TRL 7 or above, which means only salt caverns will be considered. As these are geographically constrained, it will be important for additional funding support to be made available to enable the remaining geological storage technologies to progress to TRL 7 and become eligible for future HSBM support. This is necessary to provide the range of hydrogen energy storage locations, capacities, and flexibility required for a decarbonized whole energy system.

The strategic planning process for transport and storage infrastructure will be an iterative one, informed by emerging evidence of future hydrogen supply and demand. The fixed location of production plants in the UK project pipeline provides a clear

[78] https://assets.publishing.service.gov.uk/media/657a2a92095987000d95e086/hydrogen-projects-planning-barriers-and-solutions-report.pdf.

indication of where early infrastructure could hold strategic value. There is a recognition that the development of hydrogen transport and storage infrastructure within industrial clusters should be a priority in the 2020s. The UK government does not anticipate heat being a driver of infrastructure requirements prior to the 2026 strategic decision on hydrogen for heat. Current demand estimates also indicate that the transport sector is unlikely to be a driver of infrastructure requirements in the near term.

There are still a few unknowns within the HSBM, compounded by the uncertainty surrounding the future hydrogen economy and its market dynamics. These include questions around how HSBM-supported storage facilities should be allowed to sell their storage capacity to users—how much capacity to make available, maximum pricing, differentiation by user, and government use of capacity. There are also discussions around whether a single- or multi-stage approach is most suitable. The single 15+ year contract incentivizes the construction of a facility with set rules on sales of capacity. For the multi-stage contract, the government provides the storage facility with a revenue floor in exchange for the rights to store gas in the facility, and then asks the facility to re-sell its storage rights, on the government's behalf, to storage users.

Over the 15+ years, the revenue floor remains the same, but the approach to resale of its capacity can change. In the single-stage approach, the storage facility owns the rights to store hydrogen and is bound by enduring rules set at the beginning of the contract. In the multi-stage approach, the government obtains the storage rights and can change how these rights can be resold, preserving flexibility and protecting investors from market uncertainty. There is also concern around how the government will ensure appropriate risk allocation between hydrogen producers and customers, especially given the government's position on not permitting sales through intermediaries under the Low Carbon Hydrogen Agreement. These will be addressed during the ongoing market engagement on the business models.

Hydrogen storage's economic viability hinges on reducing green hydrogen production costs along with derisking and attracting infrastructure investments. While initial capital costs remain high, technological advancements and scaling up of production are expected to drive costs down. However, it is important to consider the strategic value of hydrogen storage in a decarbonized energy system providing longer-term energy storage, grid flexibility, and decarbonization of hard-to-electrify sectors.

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