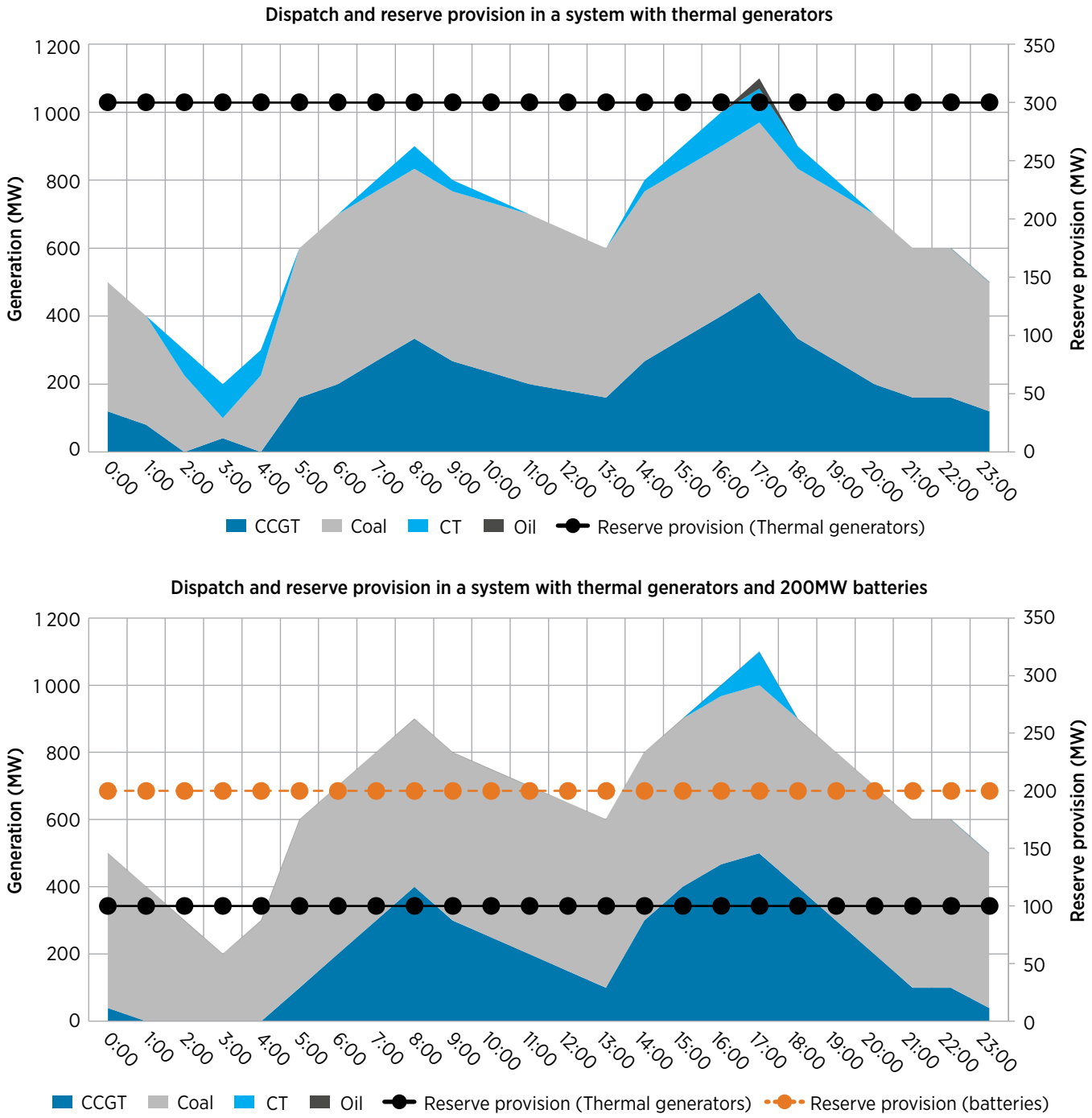
- **By reducing the congestion and losses on the T&D system, especially during peak hours.** This assumes that the storage assets are deployed upstream of the congested lines in the transmission system. As explained earlier, estimating such effects in the distribution network requires a different type of analysis from the one presented in the ESVF.
- **By allowing storage to provide reserves, which can prevent thermal power plants being committed primarily for reserve provision.** When this happens storage can provide significant savings for the system by avoiding the need to bring a more expensive unit into the merit order. Figure 23 below provides a simple example based on production cost simulation.

Figure 23: Dispatch and reserve provision with thermal generators and 200 MW of batteries



B. Marginal peaking plant cost savings

Power systems are designed with enough firm capacity to accommodate expected demand under both normal operations and contingencies. In a grid system with a growing load, the corresponding increasing peak is usually fulfilled by building new peaker capacity, the generation resources that are only utilised during peak hours. In systems with increasing proportions of VRE, peaks in the net load become higher and narrower, reducing the operating hours for peaker plants and making a business case for electricity storage with limited capacity to replace peaker plants cost-effectively. Electricity storage can potentially provide firm capacity to the system, deferring the need for new peaker plants.

However, to provide such a service, electricity storage needs to fulfil minimum capacity and storage discharge time requirements depending on regulation and market rules. When storage is coupled with VRE, it forms a hybrid plant with increased capacity credit compared to VRE alone (i.e. storage increases the firm capacity of VRE). This is another indirect way of deferring the need for peak capacity. In the system value analysis, this category refers to savings from the avoided capital costs of building peaker plants that would otherwise be needed if electricity storage was not present. If a grid system does not have increasing demand and can utilise its existing generation resources to meet the demand, cost savings in this category can be realised when peaker plants reach end of life and, instead of being replaced with new peakers, are replaced with electricity storage. As more VRE reduces the operating hours of peaker plants, early decommissioning should also be taken into account, with appropriate electricity storage as a natural replacement option.

For example, in the Massachusetts State of Charge study (DOER and MassCEC, 2016) such savings from avoided peaker plants amounted to USD 1 093 million, or nearly half of the modelled benefits.[25] Such large savings come not only from the avoided high cost of building natural gas combustion turbine peaker plants, but also the avoided cost of fuel and the grid operator's payment to procure capacity. This category is therefore highly dependent on load growth and other local procurement conditions.

C. VRE curtailment savings

With the increasing amount of VRE, grid operators sometimes have to curtail electricity generated from these resources for different reasons:

- generation exceeding transmission capacity
- ramping constraints
- need for system services from conventional generators.

In the last of these three instances, some conventional generators have to remain online to maintain minimum system inertia, provide voltage control and short-circuit current capabilities, and meet operating reserve requirements. This displaces VRE generation even when it has zero short-run marginal cost (SRMC), as thermal generators need to generate some electricity when online (the so-called minimum stable level). When VRE is very high there might be a condition where generation exceeds load, sometimes referred to as overgeneration.

Some power systems have imposed a penalty on VRE curtailment, increasing total system costs when this occurs. Storage can be used to store the excess amount of VRE generation to be used at a later time, minimising or eliminating the curtailment. This actually translates not only into increased VRE penetration in the system, but also into savings on curtailment penalties (if applicable). Note that by avoiding VRE curtailment, more VRE is integrated into the system and less fossil-fuelled generation is required; however, these savings are already accounted for in point A.

D. T&D deferral savings

T&D systems are upgraded based on the forecast peak load on each line and the power flows within a system. The peak load in the various circuits of the system, however, occurs only for a few hours in a day and is often seasonal. Placing a storage asset close to the load centre can help meet the electricity demand during peak hours without having to upgrade the incoming transmission or distribution lines, deferring the upgrade. In addition, T&D systems are usually upgraded in "chunks" because of the extended construction time. For example, if a load centre is forecast to increase by 2 MW in the next 5 years, the grid operator might plan for a 20 MW distribution grid upgrade, resulting in spare capacity for many years until the peak load reaches the additional 20 MW. Electricity storage assets, on the other hand, can be added gradually, meeting the peak load as it increases and eliminating the waste of spare capacity build-out.

Savings from T&D deferral depend on the local conditions, including load growth, existing T&D infrastructure, and where and how storage can be utilised. Such savings are therefore usually estimated on a case-by-case basis. However, they are important to consider, as they might can strengthen the business case for storage deployment (see Case 5 in Part 3 of this report, which focuses on T&D investment deferral).

E. Reactive power support savings

Because storage assets can provide both active and reactive power, placing them close to a load centre firms up the voltage of the power flowing to the load.

25 Ibid, p.87 and p.91.

This reduces the need to install standalone equipment to manage power quality[26] and saves on potential costs of damaged electronics due to poor power quality. Since storage assets are multi-functional, the reactive power support from storage is usually an additional benefit (e.g. used in conjunction with T&D deferral) that is difficult to monetise, yet might provide a specific business case in grids with poor power quality or insufficient reactive power capability, for example due to the replacement of thermal power plants with VRE.[27]

Reactive power support cannot be quantified using the optimisation models in this report; it requires different sets of tools more appropriate to power system analysis, including power quality and stability analysis (Arefifar and Mohamed, 2014).

F. Black start savings

Because electricity storage assets can provide both active and reactive power, and can be set to provide a frequency reference when coupled with grid-forming inverters, they can be used as a black start resource to restore the grid system when coupled with a synchronous generator (e.g. hydro power, compressed air energy storage) or, especially in the future, with grid-forming inverters.[28] Since storage assets are multi-functional, the black start capability from storage is essentially free when the assets are installed for other purposes (e.g. T&D deferral), provided the assets can provide such services (e.g. grid-following inverters cannot).

If there is (reliable) black start capability already on the system, there is no value in such a capability provided by storage as long as the existing assets are not at risk of retirement. Electricity storage benefits in the form of black start savings cannot be assessed with the ESVF. However, if there is no black start capability in the system, the savings are equal to a diesel genset normally used to black start a large thermal generator.

Phase 4: Simulated storage operation

The value streams discussed above can be provided by the same electricity storage resource, as storage can provide more than one value stream to the system at once. As system-level analysis is usually performed with the objective of minimising total system cost or production cost, a different type of analysis is needed to complement it. The analysis needs to simulate how a storage asset would actually bid into the market to maximise its profit by capturing multiple revenues from energy and ancillary services markets.

A report by Sandia National Laboratories (2010) discusses various combinations of services that storage can offer to increase potential benefits. When simulating storage as a price-taker, the user needs to be able to decide which services can be provided simultaneously. Based on the services the storage resource is allowed to provide, the model used in this phase should co-optimise the revenues from different services to maximise the total profit of the storage resource. These simulations are useful mostly for project developers in liberalised power systems with an electricity market; otherwise the stacked benefits of storage can be drawn from the production cost tool, as would be the case for vertically integrated utilities.

Price-taker storage dispatch model

To find out the optimal revenue of an electricity storage project, a price-taker storage dispatch model can be used to simplify the problem and to take the perspective of an agent operating a storage asset. Such a model co-optimises the revenues from various services the storage project can provide, assuming that the storage resource is a price-taker, i.e. the project receives the wholesale price for the service it provides, instead of being a marginal resource that influences the wholesale price. For example, the Electric Power Research Institute (EPRI) Storage Value Estimation Tool (StorageVET) is an open-source price-taker storage valuation tool (EPRI, 2019).

The dispatch model takes in data such as the energy and reserve prices from the system value analysis, combined with user inputs for the storage project, and outputs the storage dispatch at any given hour (see Table 7). This is accurate when a storage project is small compared to total storage capacity and system size. But it loses accuracy as project size grows, as each dispatch would also affect system-level variables that are assumed in the model to be fixed.

The dispatch model should consider the existence of a day-ahead market (DAM) and intraday markets with timescales representative of the specific market under consideration.

Figure 24 presents the type of results that identify the SOC and the different services provided for each hour. In this illustrative example, the electricity storage resource is absorbing from and injecting into the grid in the same hour based on its profit maximisation objective.

26 Note that some equipment will still be needed, in particular depending on which assets storage is replacing.

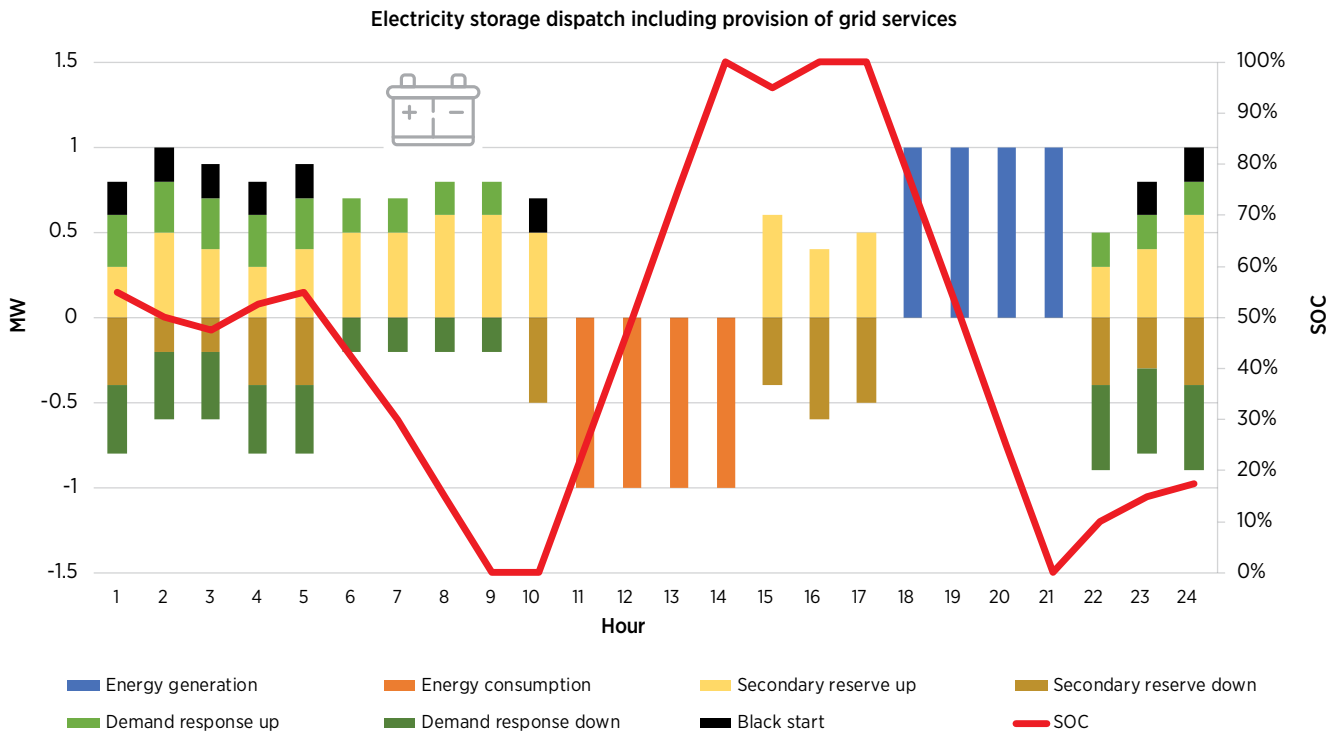
27 VRE can also provide reactive power. However, doing so reduces active power, therefore affecting the economics of VRE power plants.

28 Note that grid-forming inverters are very nascent in the industry and not a standard offering.

Table 7: Inputs and outputs from the price-taker storage dispatch model

Inputs	Outputs
From system value analysis: • energy prices • reserve prices (could also be provided as a user input, as in some markets their value is fixed or changes seasonally) • original load • modified load with storage • renewable generation.	• Storage dispatch for all services for each hour over the model horizon. • Storage SOC for the model horizon. The outputs can enhance subsequent financial analysis to determine the viability of the project.
From the user: • storage parameters (power and energy capacities, efficiency, SOC limits, etc.) • product durations • reserve utilisation ratio • reserve activation signal (optional). **Services a project could provide (user-selected portfolio):** • energy arbitrage • primary, secondary and tertiary reserves • peak shaving • price-sensitive demand response • renewables shifting • black start capability.	

Figure 24: Illustrative output from a price-taker storage dispatch model



Note: SOC = state of charge.

Phase 5: Storage project viability analysis

The next phase in the ESVF is to look at the revenues an individual storage project receives under each case, whether such revenues are enough to sustain the storage project, and if not, what are the possible remedies.

Project feasibility model

The project feasibility model is a cost–benefit analysis to assess whether the storage project providing the predefined services is cost-effective, i.e. its benefit-to-cost ratio is greater than one. In previous storage valuation analysis (EPRI and US DOE, 2013), the benefits considered were often only the monetisable benefits – the revenue streams accrued to the project owner – but not the benefits storage brings to the electricity grid system. Because such benefits to the system were not accurately attributed to an individual storage project, the analysis often found storage not cost-effective, or only cost-effective under certain conditions. In the ESVF, a more comprehensive method to account for the benefits of the electricity storage resource is proposed that includes both the revenue streams (monetisable benefits) and benefits to the grid system (non-monetisable benefits). In such valuation, the cost-effectiveness of the project is determined by assessing whether the following relationship is true.

Monetisable benefits and costs

With the energy and reserve prices from the system value analysis, and the optimal dispatch results from the price-taker storage dispatch model, the revenue of the storage project can be calculated. Based on the application ranking from the storage technology mappings – stating which technologies are most appropriate for the case – the cost side of the analysis can be determined, including CAPEX, OPEX, depreciation and taxes. The cash flow, as well as the net present value (NPV) and internal rate of return (IRR) for the project can be calculated (Figure 25).

Figure 25: Example of electricity storage project financial statements

NPV: -1,326,841 **IRR:** 9.55%

Financial Statement	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 6
Benefits								
Reserves provision	0	2 796 635	2 936 467	3 076 299	3 216 131	3 355 963	3 495 794	3 635 626
Discharge Revenue	0	2 821 368	2 906 009	2 993 189	3 082 985	3 175 474	3 270 738	3 368 861
Capacity Payments	0	8 160 000	8 160 000	8 160 000	8 160 000	8 160 000	8 160 000	8 160 000
VRE curtailment reduction	0	116 636	116 636	116 636	116 636	116 636	116 636	116 636
Income statement								
Total Benefits	0	13 894 639	14 119 112	14 346 124	14 575 752	14 808 073	15 043 168	15 281 123
Charging Cost	0	-1 926 872	-1 984 678	-2 044 218	-2 105 545	-2 168 711	-2 233 772	-2 300 785
Operational Expenses	0	-240 000	-247 200	-254 616	-262 254	-270 122	-278 226	-286 573
Depreciation	0	-63 360 000	-7 920 000	-3 960 000	-2 376 000	-1 584 000	0	0
Taxable Income	0	-51 632 233	3 967 234	8 087 290	9 831 953	10 785 240	12 531 170	12 693 765
Tax	0	0	-1 190 170	-2 426 187	-2 949 586	-3 235 572	-3 759 351	-3 808 130
Net Operating Income	0	-51 632 233	2 777 064	5 661 103	6 882 367	7 549 668	8 771 819	8 885 636
Cash flows								
CapEx	-79 200 000	0	0	0	0	0	0	0
EBITDA	0	11 727 767	11 887 234	12 047 290	12 207 953	12 369 240	12 531 170	12 693 765
Less: Tax	0	0	-1 190 170	-2 426 187	-2 949 586	-3 235 572	-3 759 351	-3 808 130
ITC Benefit	0	4 752 000	4 752 000	4 752 000	4 752 000	4 752 000	0	0
Free Cash Flows	-79 200 000	16 479 767	15 449 064	14 373 103	14 010 367	13 885 668	8 771 819	8 885 636

Notes: EBITDA = earnings before interest, tax, depreciation and amortisation; ITC = investment tax credit.

Assigning system value to individual storage projects

The actual system value of a storage project depends highly on the existing power system it is added to. If there is very little storage currently in the power system, adding a storage project might create a lot of system value, for example, by replacing peaking capacity or deferring transmission investment. Here, the average system value of a storage project providing a specific set of services is calculated based on outputs from the system value analysis. The proposed method below scales the system value down to the project level depending on the uses and the C-rating of the project.

The calculation follows the steps outlined here:

Step 1:

System value analysis determines the electricity storage MW and MWh potential categorised by C-rate, and the system value of each benefit category if the proposed storage is deployed on the entire grid system (Table 8 and Table 9).

Step 2:

Weights are assigned to different C-rates in individual benefit categories to reflect how the storage is used. For example, ancillary services can be fulfilled by short-duration storage; the weighting for 2C and 1C storage is therefore higher in these benefit categories (Table 10). Alternatively, production cost simulations could be used to assess the technical affinity of storage of various durations for specific services and assign weights accordingly.

Step 3:

The weightings are applied to the system values of each benefit category to arrive at the benefit for each C-rate (Table 11).

Step 4:

The system value per MW for each benefit category is determined based on the C-rate of storage (Table 12).

Table 8: Illustrative example of storage MW and MWh potential

Category	Power (MW)	Category	Energy (MWh)
Short duration	72	Short duration (2C)	36
Medium-short duration (1C)	344	Medium-short duration (1C)	344
Medium-long duration (0.5C)	645	Medium-long duration (0.5C)	1290
Long duration (0.25C)	1670	Long duration (0.25C)	6679
Total MW	**2731**	**Total MW**	**8349**

Table 9: Illustrative example of monetary value of benefits to the system

Benefit categories	Benefit bucket	Value (USD)
Generation cost reduction	Fuel cost savings	380 035 285
	VO&M cost savings	24 713 782
T&D cost reduction	Reactive power support savings	4 347
	T&D deferral savings	8 998 297
	Black start savings	899 830
Reduced peak	Peaking plant capital savings	1 587 934 758

Table 10: Example of weights assigned according to C-rate needed for a given benefit

Benefit categories	Benefit bucket	Weightage			
		2C	1C	0.5C	0.25C
Generation cost reduction	Fuel cost savings	0	0	0.3	0.7
	VO&M cost savings	0	0	0.3	0.7
T&D cost reduction	Reactive power support savings	0.25	0.25	0.25	0.25
	T&D deferral savings	0	0	0.3	0.7
	Black start savings	0.5	0.5	0	0
Reduced peak	Peaking plant capital savings	0	0.3	0.3	0.4

Table 11: Illustrative example of benefits by C-rate (all values in USD)

Benefit categories	Benefit bucket	Weightage			
		2C	1C	0.5C	0.25C
Generation cost reduction	Fuel cost savings	0	0	114 010 586	266 024 700
	VO&M cost savings	0	0	7 414 135	17 299 647
T&D cost reduction	Reactive power support savings	1 087	1 087	1 087	1 087
	T&D deferral savings	0	0	2 699 489	6 298 808
	Black start savings	449 915	449 915	0	0
Reduced peak	Peaking plant capital savings	0	476 380 427	476 380 427	635 173 903

Table 12: Illustrative example of benefits by C-rate (all values in USD)

		Energy storage size			
		2C	1C	0.5C	0.25C
		72	344	645	1670
Benefit categories	Benefit bucket	USD/MW	USD/MW	USD/MW	USD/MW
		2C	1C	0.5C	0.25C
Generation cost reduction	Fuel cost savings	0	0	176 826	159 314
	VO&M cost savings	0	0	11 499	10 360
T&D cost reduction	Reactive power support savings	15	3	2	1
	T&D deferral savings	0	0	4 187	3 772
	Black start savings	6 271	1 306	0	0
Reduced peak	Peaking plant capital savings	0	1 383 138	738 849	380 387

After accounting for the monetisable revenues and system value, as well as the costs of an electricity storage project, the project feasibility model should stack up the monetisable revenues and compare them to the costs.

Economic viability gap and missing money issue

Figure 26 shows an example of the outcome from a project feasibility model. In this particular example, although the system benefits combined outweigh the costs, the monetisable benefits (i.e. project revenues) are less than the costs, making the project economically infeasible for the project owner. The difference between the cost and the monetisable benefit, or the economic viability gap, if greater than zero, could be due to the regulatory framework that does not allow storage to capture revenues in line with its system value, missing an opportunity for total system cost reduction.

Most VRE and electricity storage technologies bear higher fixed costs and lower variable operating costs when compared to fossil fuel technologies. In many cases, the market does not compensate the resources for their long-run marginal costs fairly, resulting in depressed electricity prices. There are therefore insufficient revenues to cover the CAPEX and fixed OPEX for the VRE and storage resources, the problem commonly referred to as the "missing money issue" (Bushnell, Flagg and Mansur, 2017; Hogan, 2017; NREL, 2015).

When comparing the costs and benefits of the storage project, there are three different potential outcomes (Figure 27):

a. If the monetised benefits are greater than the costs of storage, the project is viable.

b. If the system value is lower than the cost of the project, the project has a benefit-to-cost ratio lower than one and is not worth pursuing.

c. If the system value of the project exceeds the costs of storage, but the monetisable benefits are lower than the costs, the project has a benefit-to-cost ratio greater than one, but cannot be developed because the monetisable benefits are too low. This is when policy makers and regulators can use the results to identify the economic viability gap and devise appropriate incentives or adjustments to the regulatory framework, so that these projects are developed to realise the system value and reduce total system cost.

Figure 26: Cost and benefit analysis

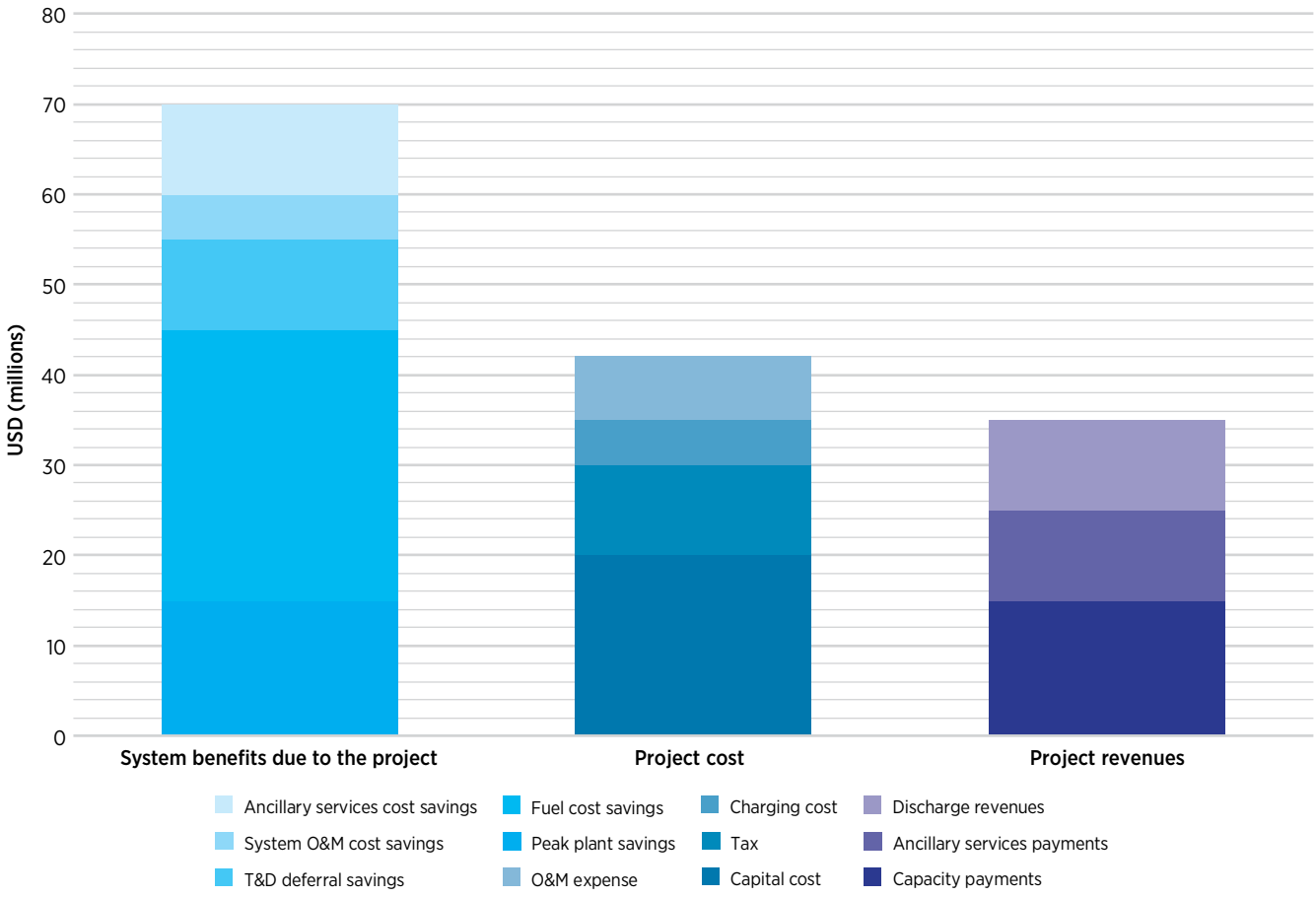
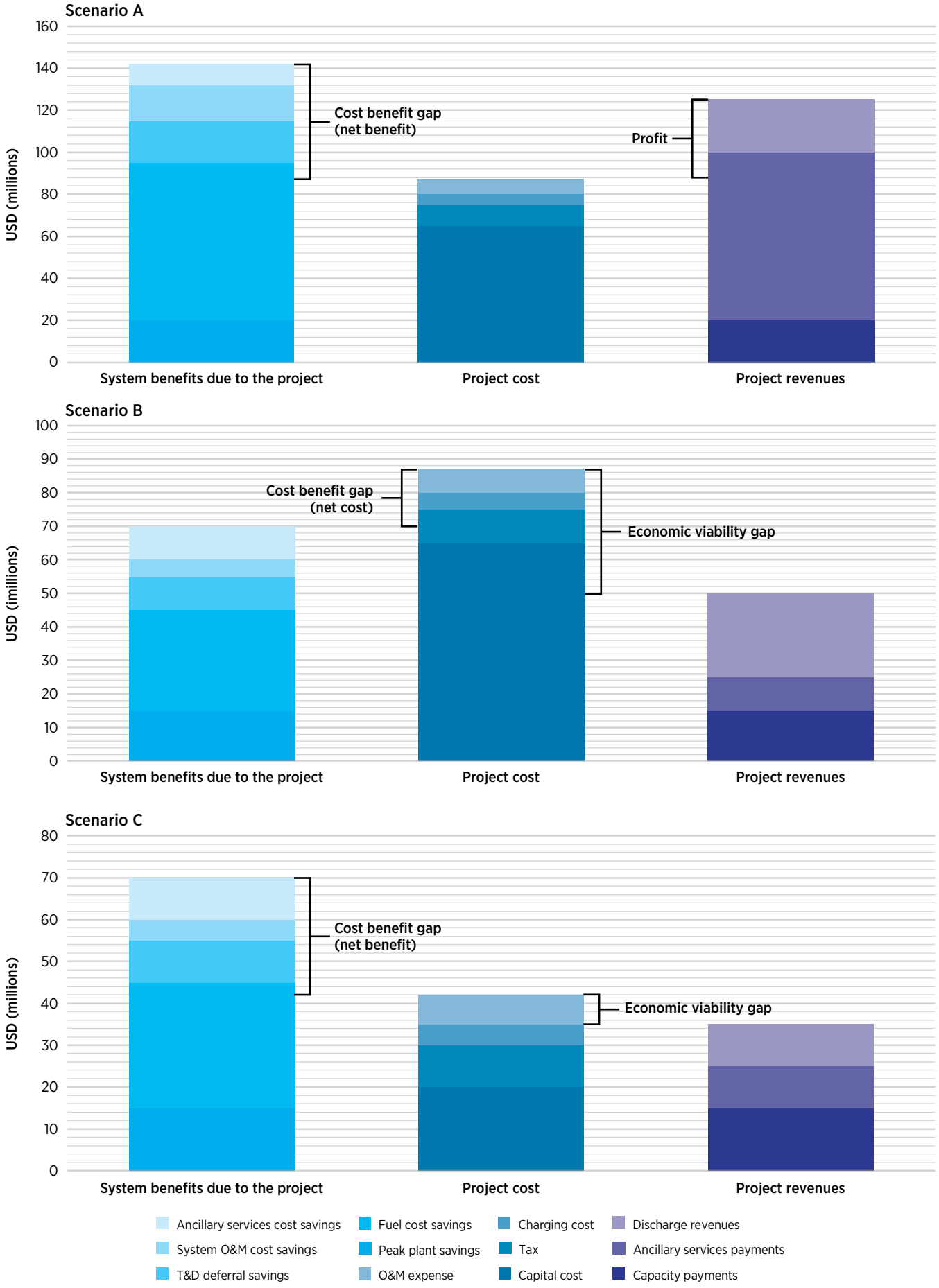


Figure 27: Outcome of three scenarios subject to cost–benefit analysis



In the case of Scenario C depicted above, various measures can be implemented to change the economics of the project. These are discussed in some detail in Part 1 of this report (see policy recommendations), but are not the main objective of this report. For a complete overview of policies that might be relevant to increase the participation of electricity storage in electricity markets and increase its monetisable revenues, please see IRENA, IEA and REN21 (2018).

Revenue stacking is crucial to assess the viability and properly value the benefits of electricity storage

3. Conclusions

Using power system models to assess value and viability

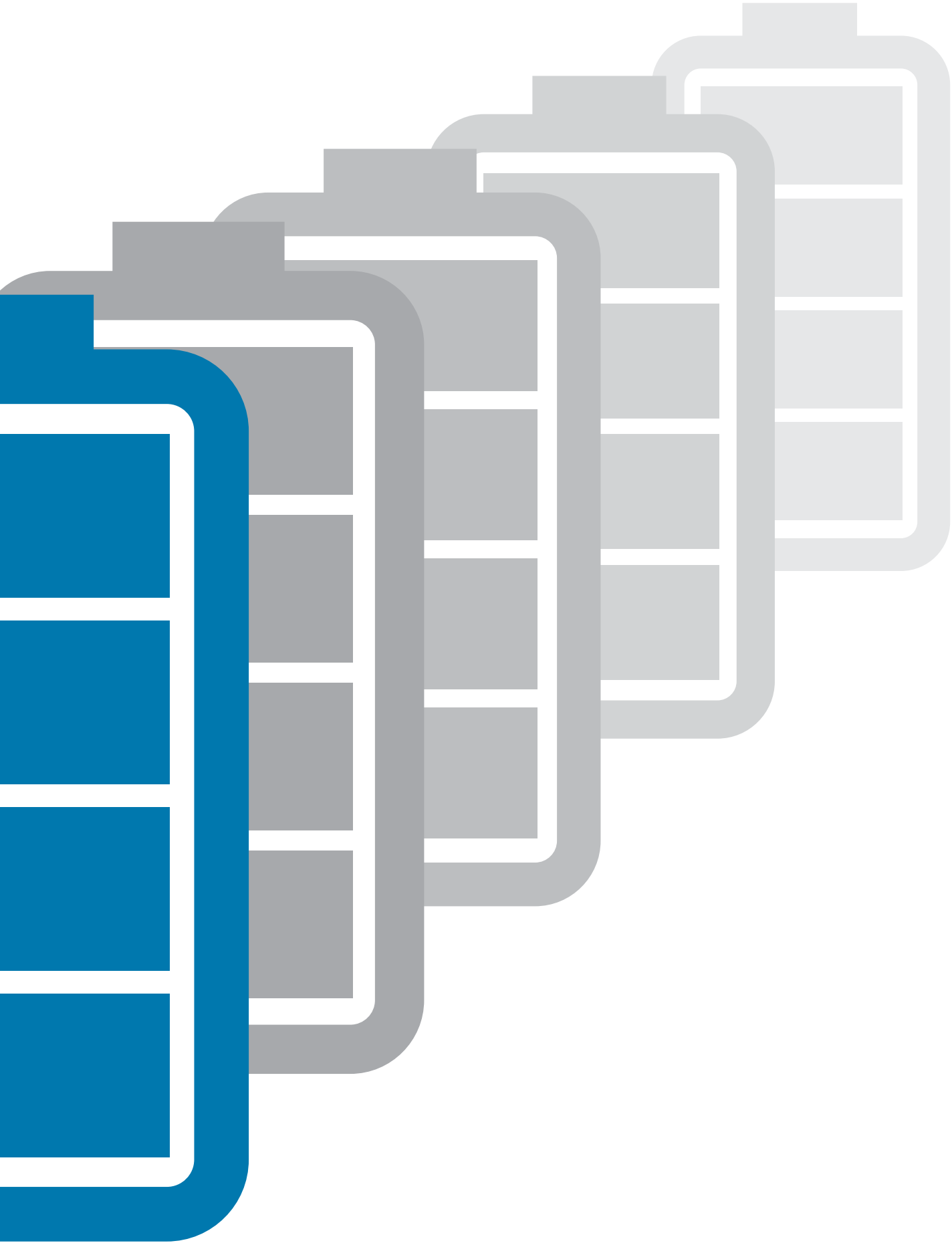
As the proportion of VRE in power systems increases, electricity storage is becoming recognised by stakeholders as an important tool for effective VRE integration. Several examples of how electricity storage can facilitate VRE integration are discussed in the next part of this report (Part 3), showing how early business cases are already driving deployment of storage in some jurisdictions. Depending on the primary service the electricity storage provides, however, other technologies may be capable of meeting the same need. The cost-effectiveness of electricity storage must therefore be assessed at system level and compared against other technologies.

Past research has demonstrated that stacking revenues from the variety of services that electricity storage can provide is key to accurately accounting for the benefits of electricity storage, as well as a necessary condition for its commercial viability. The ESVF described in this report puts emphasis on the benefits (including revenue streams) electricity storage can bring both to its owners and, more importantly, to the power system.

The framework examines the services that electricity storage can provide, and storage technologies are compared in their suitability to providing these services. The power system with and without electricity storage is then evaluated to determine the benefits it can bring to the grid. Dispatch of an individual electricity storage project is then modelled and, finally, its economic viability is assessed to determine whether policy interventions are needed to incentivise project development. The phases set out in the framework are necessary steps to properly evaluate the benefits that electricity storage can bring to the power system.

At project level, system benefits of storage are categorised as monetisable or non-monetisable. If the total benefits exceed costs, but monetised benefits are less than costs, this implies that project developers/owners do not have enough economic incentive to build a project even if it has a benefit-to-cost ratio of greater than 1. In this case, policy intervention is likely to be needed to incentivise the development of such a project so as to capture the overall social good.


Photograph: Shutterstock



Part 3: Real-world cases of storage use in power systems

Introduction

Renewable energy has advanced rapidly in recent years, driven by innovation, increased competitiveness and policy support. This has led to the increased deployment of renewable energy technologies worldwide, with their share of annual global power generation rising from 25% today to 86% in 2050 under the International Renewable Energy Agency (IRENA) Paris-compliant REmap scenario (IRENA, 2019a). In the same year about 60% of total generation comes from variable renewable energy (VRE), mainly solar photovoltaic (PV) and wind, which are characterised by variability and uncertainty.

As the VRE share increases, power systems are confronted with new challenges related to operation and planning, and a more flexible energy system is required to ensure a reliable and effective integration of these resources. Traditionally flexibility has been provided by conventional thermal generation with high ramping capability or low minimum load, such as open-cycle gas turbines (OCGTs); however, flexibility now has to be sought from all energy sectors, including energy storage systems (IRENA, 2018a). Electricity storage is one of the main solutions for a renewable-powered future considered in the IRENA Innovation Landscape Report (2019b).

Electricity storage systems have the potential to be a key technology for the integration of VRE due to their capability to quickly absorb, store and then reinject electricity to the grid. Because of this, electricity storage is gaining an increasing interest among stakeholders in the power sector. Policy makers therefore need to understand the value of these resources from a technology-neutral perspective. The IRENA Electricity Storage Valuation Framework (ESVF) aims to guide the development of effective electricity storage policies for the integration of VRE generation. The ESVF shows how to value storage in the integration of variable renewable power generation. This is shown in Figure 28.

Part 1 of the proposed framework provides power system decision makers, regulators and grid operators with an understanding of how to value electricity storage in the grid system.

It provides an overview of the ESVF, describing its components and the sequence of analytical steps that it uses to quantify the benefits of electricity storage.

Part 2 provides a detailed description of the ESVF methodology and is directed at power system experts and modellers who may wish to adopt this approach for the cost–benefit analysis of electricity storage projects.
In this third and final part, the goal is to present eight selected cases of energy storage use in practice. Typical uses are corroborated by examples of cost-effective deployment of storage based on a specific case, where they are often supported by additional revenues from other uses, highlighting the ability of storage to stack multiple revenue streams.

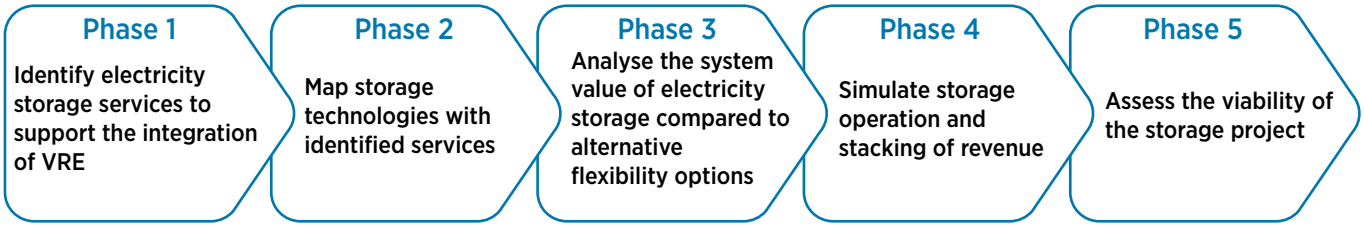
Each case aims to provide concrete examples of a) how such uses are driven by accelerated deployment of VRE, b) how the challenges have been transformed into a business case, c) how this led to storage deployment, and d) how storage is performing in the provision of these services compared to other grid assets or generators.

The eight cases selected are (in order of presentation in this report):

1. **Operating reserves**
2. **Flexible ramping**
3. **Energy arbitrage**
4. **VRE smoothing**
5. **T&D investment deferral**
6. **Peaking plant capital savings**
7. **Enabling high shares of VRE in an off-grid context**
8. **Behind-the-meter electricity storage.**

Cases 1 to 7 focus on large-scale system-level storage systems, but note that most of these can also be applied to small-scale storage systems. Small-scale storage systems are addressed separately in case 8, which focuses on behind-the-meter electricity storage.

Figure 28: Electricity storage valuation framework: How to value storage alongside VRE integration



Case 1: Operating reserves

1. Challenge – Increased need for operational reserves and a faster response

To ensure a secure and reliable electricity supply, generation has to equal demand at all times. Any mismatch between supply and demand manifests itself as a deviation in grid frequency from its nominal value. If generation exceeds demand, then the frequency will increase, while it will decrease if generation falls short of demand. Any immediate decline or surge in frequency is initially slowed down by the inertia of synchronous generators and then halted by the governors' droop response of generators with that capability.[29] Additionally, system operators procure a set of fast-acting operating reserves to bridge any mismatches between supply and demand.

Operating reserves can be defined as the additional capacity (generation and responsive load availability) above the capacity needed to meet the actual load demand, which is made available either online or on standby to assist in case of load increase or generation decrease (Ela, Milligan and Kirby, 2011). There are different types of operating reserves, with different nomenclatures depending on the power system. Figure 29 shows a summary of operating reserves using the European nomenclature.

When the share of variable renewable energy (VRE) in the system is low, operating reserve requirements have traditionally been defined as a percentage of the load or as the largest contingency of the system, or in other words, the largest generating unit at that time. With this low VRE penetration, reserves have been divided into FCR or primary reserves, FRR or secondary reserves and RR or tertiary reserves. FCR is used to stop the frequency deviation and needs to act within the first seconds after the contingency, FRR restores the frequency to its nominal value and acts within 30 seconds and RR is used to replace the FRR and acts within 15 minutes.

With low VRE penetration, system inertia is high and therefore the rate of change of frequency (RoCoF) is low and is enough for the system to have a frequency response within seconds. However, when VRE penetration is high, given that technologies such as wind and solar PV are non-synchronous, the system's inertia is reduced, increasing the RoCoF and hence threatening system reliability if not planned well in advance. An example of this is the South Australian power outage that took place in September 2016 (AEMO, 2017a).[30]

Apart from this, high solar and wind penetration means the variability and uncertainty introduced by these resources must be taken into account, and that system reserve requirements might need to be increased to cover forecast errors for VRE. The question of how to include this forecast error into reserve requirements has been widely researched in literature and is beyond the scope of this brief.

This brief focuses on the definition of new operating reserves, in which storage is a suitable technology to participate, and how these new reserve products have led to the deployment of more storage in some power systems.

2. Innovative products to provide reserves

Electricity storage, with minimal idle costs and ability to provide full output in a matter of hundreds of milliseconds, is an ideal resource to provide operating reserves. Batteries can provide a faster response than other products (for example, gas turbines) and hence there is less product requirement. Batteries can provide a faster response than thermal generators. This means specific products, such as FFR (or enhanced frequency response [EFR]), can be designed to replace multiple units of conventional primary reserve products with a single more responsive unit. However, storage has high investment costs and has to compete against other potential reserve resources – including curtailed VRE and demand response with relevant capabilities. For this reason, innovative products could be useful to unlock the full value of storage to the system.

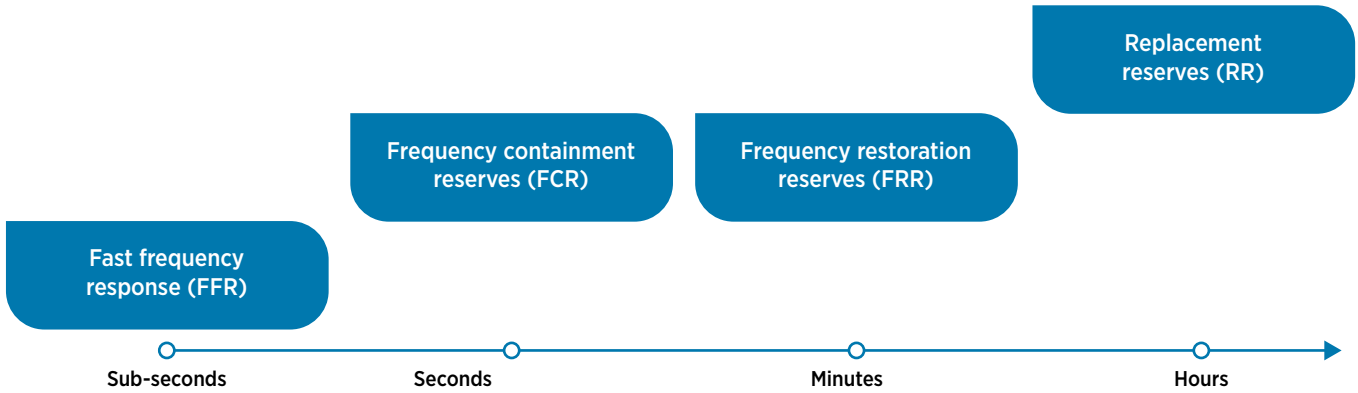
29 Non-synchronous governors can also respond. However, inverters do not have inherent inertia, but inertia-like response can be programmed. Proper response is undergoing research and development.

30 On 26 September 2016 tornadoes damaged three transmission lines and caused them to trip. This resulted in six successive voltage dips in the South Australian grid. These faults caused a protection feature of the wind farms to be activated and caused a 456 megawatt (MW) generation reduction in the region that increased the power flow through the Heywood interconnector, which made it trip This loss, and the high RoCoF of the area given the high VRE penetration and the Murraylink direct-current interconnector, provoked a quick frequency drop that the system could not handle, ultimately causing a blackout.

In this regard, the United Kingdom system operator, National Grid, developed the EFR product, which it defines as a dynamic service where the active power changes proportionally in response to changes in system frequency. The EFR service was created specifically for energy storage and requires a response within 1 second once the frequency has crossed a threshold, which can be either ±0.05 hertz (Hz) (service 1, wide-band) or ±0.015 Hz (service 2, narrow-band). In Figure 30 the EFR service is positioned with respect to the other frequency response services in the United Kingdom.

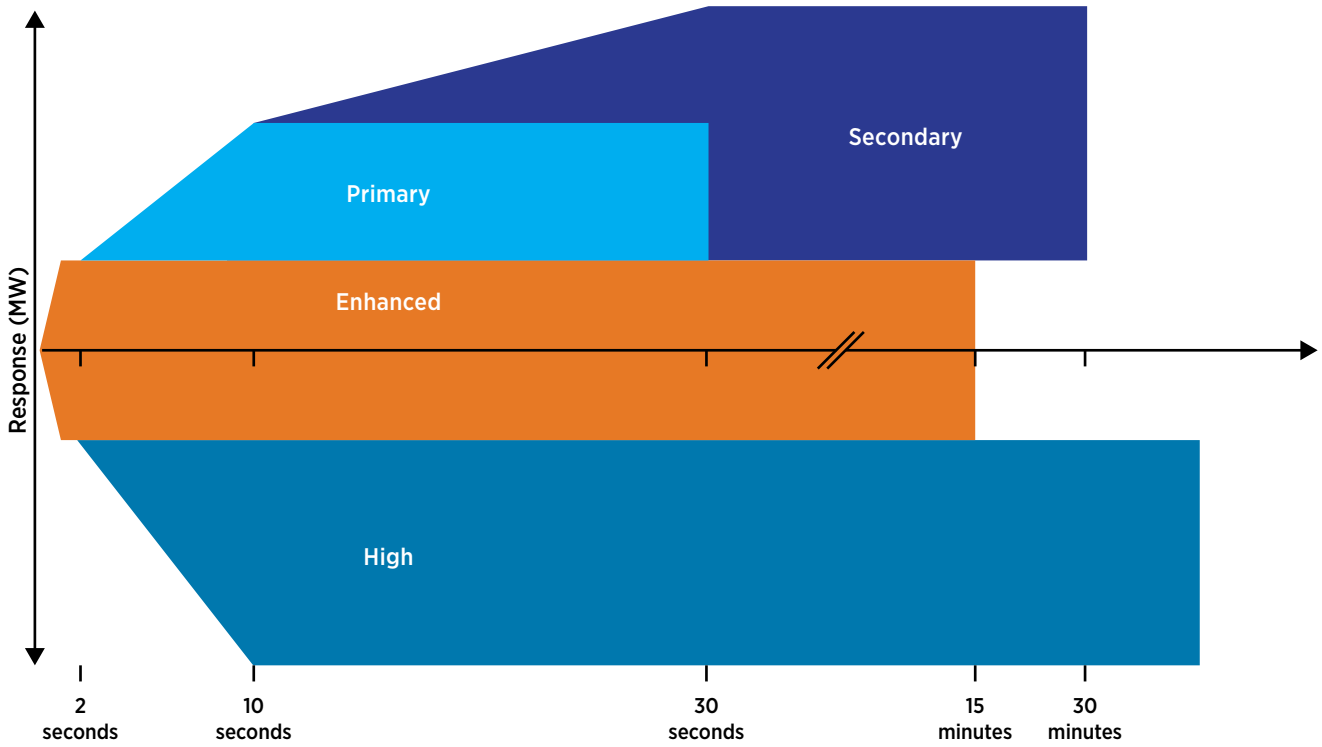
Forecast errors for solar and wind must be taken into account when calculating the system reserve requirements to deal with net load uncertainty

Figure 29: Summary of operating reserves



Source: IRENA (2018a)

Figure 30: Frequency response services in the United Kingdom



Source: National Grid (2016a)

Besides the EFR product, which is already implemented and being used in daily system operation in the United Kingdom, there are other examples of power systems with similar products that, although not implemented yet, will encourage the participation of energy storage in reserve provision. For example, the Australian Energy Market Operator (AEMO) has developed an FFR product. AEMO refers to it as "the delivery of a rapid active power increase or decrease by generation or load in a timeframe of two seconds or less, to correct a supply–demand imbalance and assist in managing power system frequency" (AEMO, 2017b).

Another example is the FFR product that the Electric Reliability Council of Texas (ERCOT) approved on 12 February 2019 and which will be implemented no earlier than January 2020. It will be a sub-product of the Responsive Reserve Service[31] (RRS) and will be triggered with a frequency of 59.85 Hz,[32] will need full response in 0.25 seconds and will require a duration of 15 minutes (Matevosyan, 2019). This last requirement will be crucial for the participation of storage, as enough energy will have to be stored to discharge for 15 minutes.

The introduction of these products enables a fast response of the system to frequency variations. This will ultimately result in a minimum required inertia online, as proven in ERCOT, which introduced an inertia constraint to the system to control the RoCoF. Here ERCOT calculates the minimum (or critical) inertia as the inertia needed online so that load resources can respond to the tripping of the largest generating unit before frequency falls below 59.3 Hz (note that load resources can respond in 0.5 seconds) (Matevosyan, 2019). ERCOT references demand response, but storage could also be applicable given its fast response capabilities.

3. Impact of operational reserves on storage deployment

Storage deployment in being incentivised in some regions by the need for a faster frequency response and the design of new products where energy storage can obtain an additional revenue stream.

In August 2016, for example, National Grid launched a 200 MW auction to provide EFR in the United Kingdom. This auction received 64 bids, of which 61 were battery storage projects, 2 were demand response and 1 was thermal generation. Of these bids, National Grid selected 8 battery storage projects with an average price of GBP 9.44 per MW of EFR per hour, to secure a total of 201 MW of battery storage for 4 years (National Grid, 2016b). Specific examples from this auction are the two projects awarded to Low Carbon to install lithium ion (Li-ion) batteries in Glassenbury (40 MW) and Cleator (10 MW). Glassenbury (Figure 31) has a net capacity of 28 megawatt hours (MWh), while Cleator's net capacity is 7 MWh. These two projects currently provide a quarter of the total EFR capacity in the United Kingdom and help to stabilise the frequency in its grid (Low Carbon, 2019).

Figure 31: Low Carbon's Glassenbury project

Source: Low Carbon (2019).

31 Similar to FCR or primary reserve.

32 Note that in the United States the frequency of the system is 60 Hz and not 50 Hz.

Figure 32: Hornsdale power reserve project in South Australia

Source: Tesla

Another example of storage deployment to provide frequency regulation is the 100 MW/129 MWh battery project that Tesla has installed in South Australia under the name Hornsdale Power Reserve, given its proximity to the 309 MW Hornsdale wind farm in Jamestown (Figure 32). This project was the largest Li-ion battery installation in the world at the time it was deployed. Commissioned after the South Australian blackout in 2016 to provide frequency control and short-term network security services, it has been operational since 1 December 2017 (Hornsdale Power Reserve, 2019). The total battery cost was AUD 89 million, which leads to AUD 690 per kilowatt hour (kWh). This price seems high, given the cost of the Tesla Powerwall at the time was AUD 642/kWh, but the battery had to be built in 100 days and only Tesla could make an offer to fit the requirements, therefore increasing the price (Brakels, 2018).

4. Storage providing operating reserves

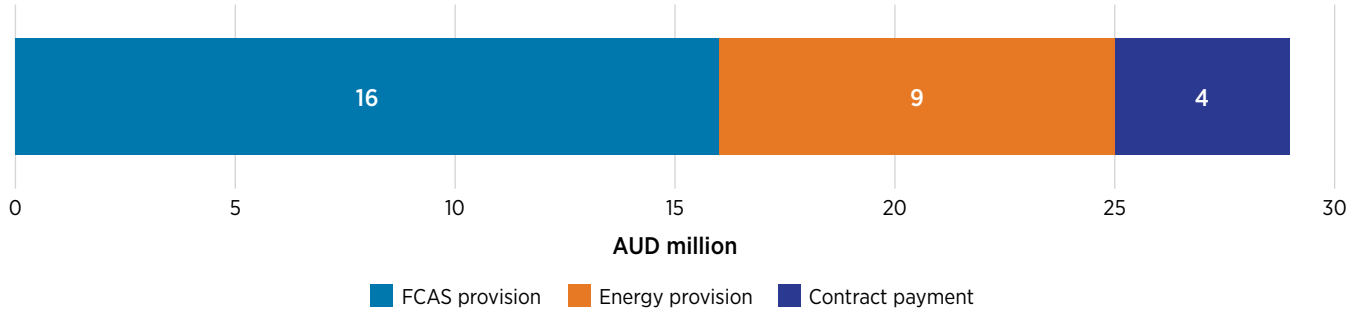
The projects mentioned in the previous section are already operational and supporting their respective power systems with frequency stabilisation.

In the case of the United Kingdom, there are no data on how the storage projects are providing EFR, since this service is still not open to every market participant; however, EFR is expected to be incorporated in the frequency response market in the future. This service is currently provided by the eight projects from the tender as required by the system operator. The only available information on how storage can provide this service is found in academic papers such as Canevese et al. (2017), where a simulation of a battery providing EFR in the United Kingdom and in continental Europe is made.

In the South Australian case, battery dispatch information is available on the Hornsdale Power Reserve website (Hornsdale Power Reserve, 2019); however, the battery is stacking energy arbitrage and frequency control ancillary services (FCAS) provision, and the value of the battery is not fully clear. However, given that the battery has already been operating for over a year, some authors have analysed the value that it provides and the revenues it brings. First, Neoen, the company that owns the project, earns AUD 4 million (about USD 2.8 million) every year and will do so for 10 years so the government can use 90 MW and 10 MWh of the battery for FCAS provision. Therefore, this revenue is obtained just for being available, similar to a subsidy (Brakels, 2018). The rest of the capacity (30 MW/119 MWh) can be used to participate in different markets, and this is where the battery has earned the bulk of its revenue.

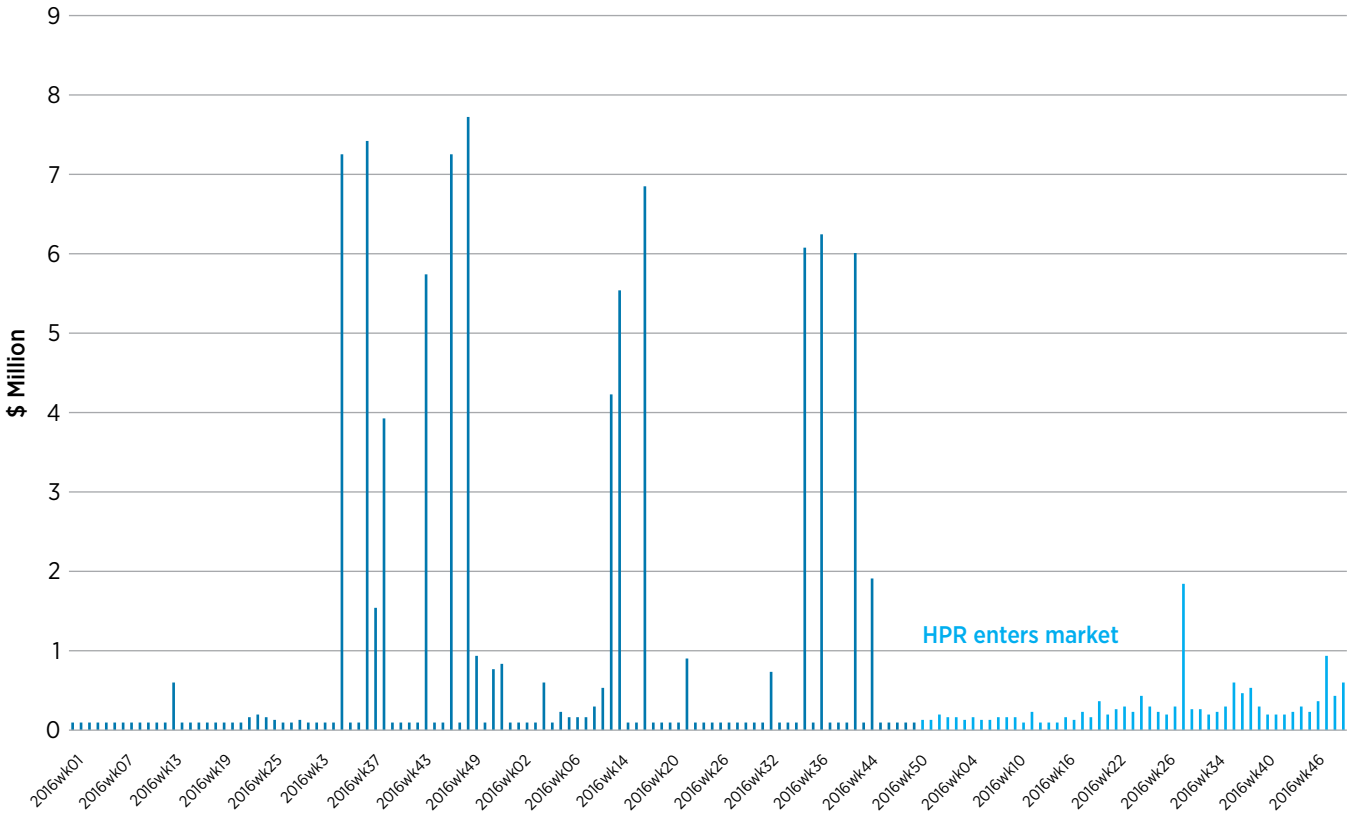
Excluding the yearly AUD 4 million (USD 2.8 million), the battery's total revenues from providing FCAS and arbitrage were AUD 25 million (about USD 17.5 million) in 2018 (Figure 33). Additionally, AEMO stated that in Q4 2018 the battery obtained AUD 4 million from the FCAS market alone (Parkinson, 2019). Assuming this is repeated every quarter, of the AUD 25 million, AUD 16 million would be from FCAS provision and AUD 9 million from energy arbitrage. Therefore, FCAS provision is its main source of revenue. Additionally, assuming revenue of AUD 29 million (25 + 4) is obtained per year, the project will recover its investments costs (AUD 89 million; over USD 60 million) in around four years. Despite this, Tesla claims it has not been paid for more than a third of the FCAS its batteries have provided in South Australia because it is too fast to be counted (Cunsolo, 2018), but as explained in the previous section, AEMO is planning to implement an FFR service from which the battery would be able to increase its revenue stream.

Figure 33: Hornsdale Power Reserve revenues in 2018



Based on data from: Brakels (2018) and Parkinson (2019)
AUD 1 = c. USD 0.70

Figure 34: South Australian total regulation FCAS payments

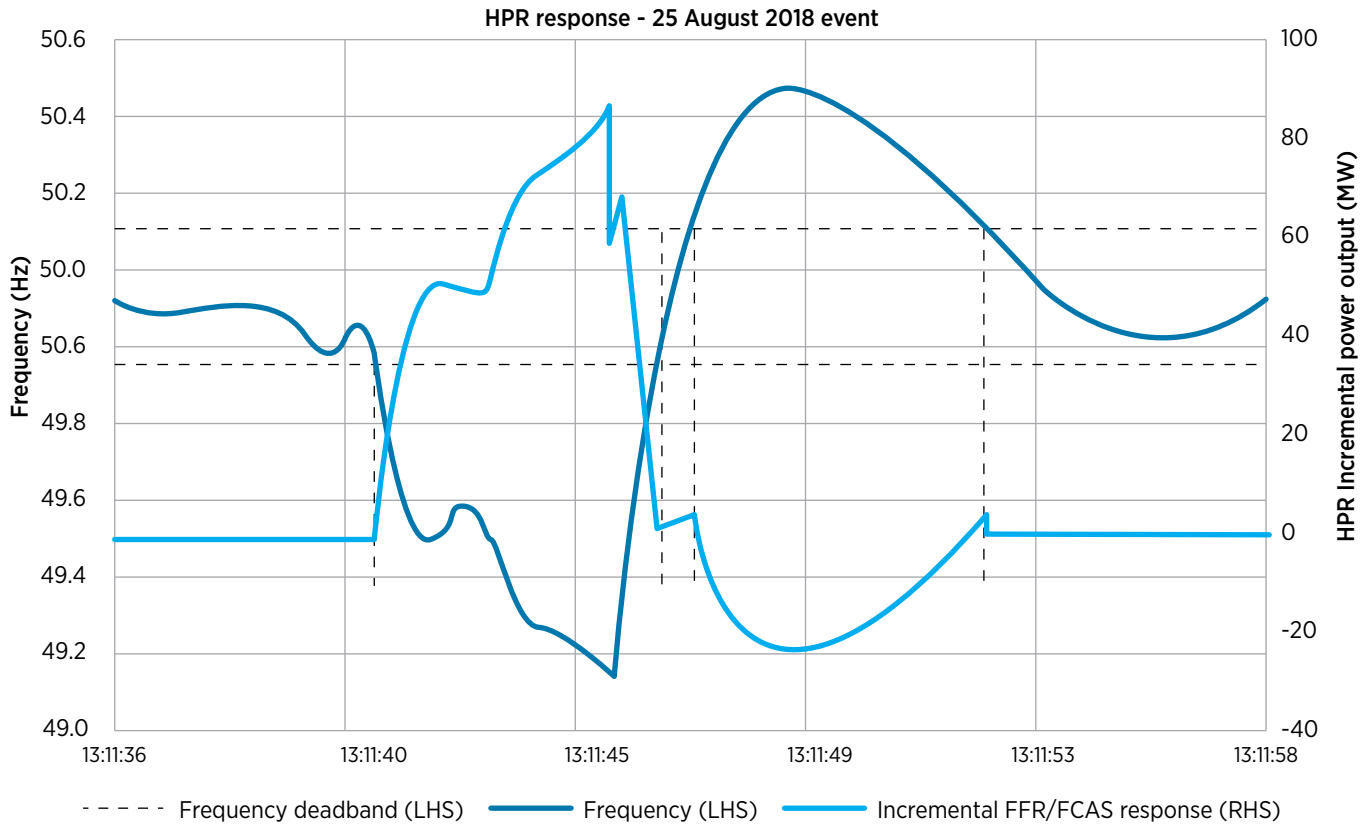


Note: HPR = Hornsdale Power Reserve.
Source: Parkinson (2018).

As for the value, batteries are proven to have lowered the cost of FCAS in South Australia, as shown in Figure 34. Data show that during the end of 2016 and in 2017 payments to existing fossil fuel generators were very high, being over AUD 7 million in some six-week periods. With the installation of the Hornsdale project, this service can be provided in a cheaper way. In 2018 the total savings in the FCAS market are estimated at AUD 40 million (Parkinson, 2018).

Besides the economics, the battery also provides fast response that keeps the frequency within predefined limits. This was proven on 25 August 2018 when the battery prevented load shedding. On this date lightning hit power lines in northern New South Wales, which shut down all the interconnectors between South Australia and other states. At the moment this occurred, South Australia was importing energy from Victoria and therefore it created an energy shortage that caused a frequency drop. However, thanks to Hornsdale, which responded in 0.1 seconds, the power system kept operating normally (Brakels, 2018).

Figure 35: Response of Hornsdale during the underfrequency event of 25 August 2018 in South Australia



Source: Brakels (2018).

This is illustrated in Figure 35. When the frequency suddenly dropped, the battery's output rose to 80 MW to provide stability. Given the large increase in generation, the frequency went in the opposite direction, reaching over 50.4 Hz, at which time the battery started charging at -20 MW to decrease the frequency. After this, the frequency was already stabilised (within security limits) and the battery went back on standby.

5. Conclusions (Case 1: Operating reserves)

Power systems with a high proportion of non-synchronous generation (e.g. from VRE), and therefore low inertia, require a faster response from resources in order to stop the frequency variations produced by a power imbalance. Resources such as storage systems are, in this context, highly suitable technologies that can provide a fast response to any power imbalance. However, the development of market products in which storage can offer this fast response might be required to incentivise its deployment.

The United Kingdom has already implemented the EFR service, leading to the deployment of 201 MW of energy storage in the system to provide frequency response. In the South Australian system, a 100 MW, 129 MWh Tesla battery has been deployed to provide FCAS and energy arbitrage services. Its deployment yielded around AUD 40 million of savings in the FCAS market in 2018 and prevented the system from potential blackouts.

Tesla claims it has not been paid for more than a third of the FCAS its battery has provided in South Australia because it is too fast to be counted; however, AEMO is planning to introduce an FFR service soon, in which this battery could be especially suitable to participate. Finally, ERCOT is due to implement an FFR service by 2020, after its approval in February 2019.

6. Further reading

Innovative ancillary services are one of the 30 innovations considered in the IRENA Innovation Landscape Report. For more information read:

IRENA (2019), "Innovation Landscape Brief: Innovative ancillary services", International Renewable Energy Agency, Abu Dhabi.

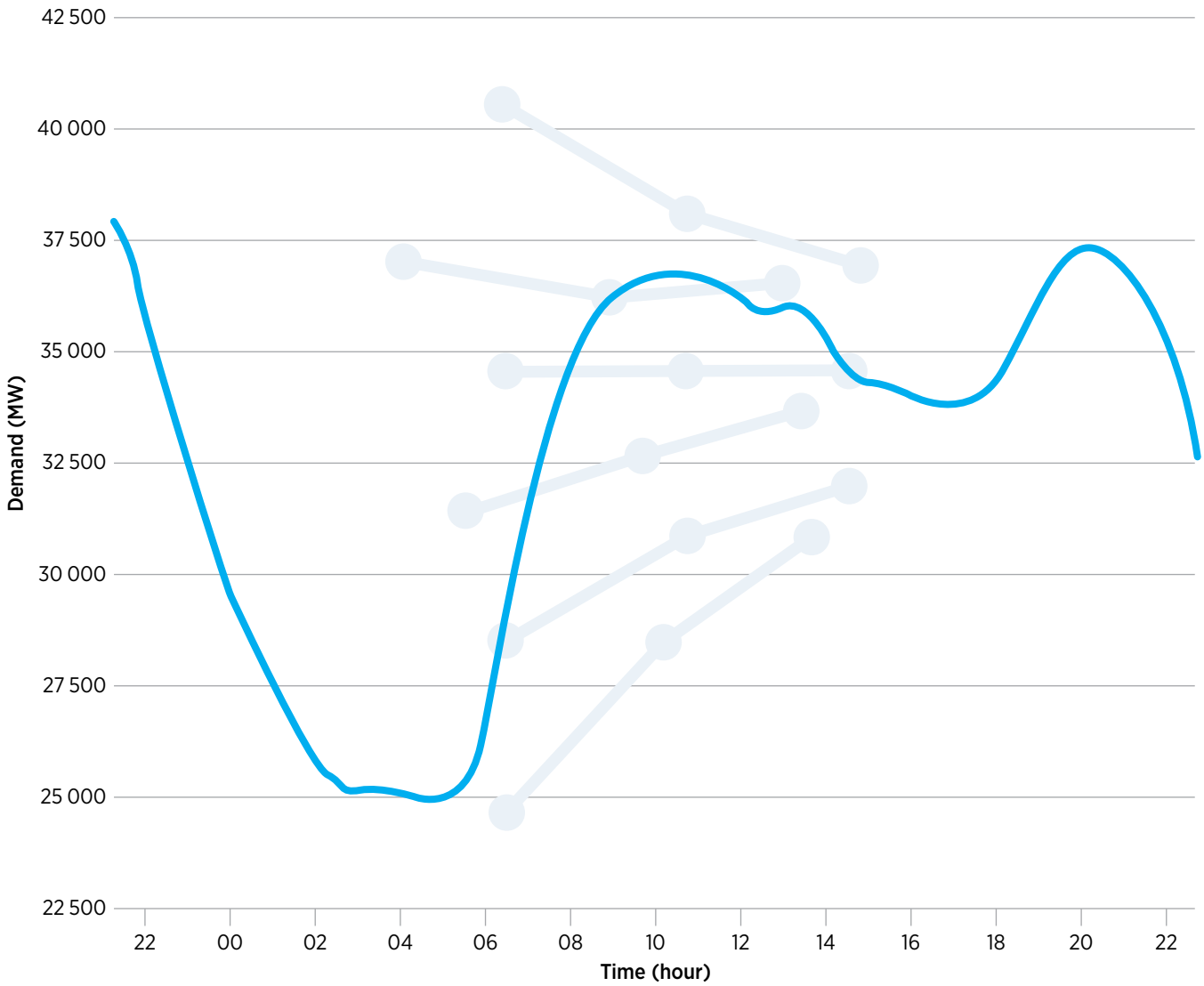
Case 2: Flexible ramping

1. Challenge – The duck curve

One of the most characteristic curves in power system analysis is the demand or load curve, which represents the energy required by customers in every period (seconds, minutes, hours). In power systems where VRE penetration is low, this curve is often characterised by two peaks, the first one in the morning when people are at home getting ready to go to work, and the second in the evening when people come back from work and use their electrical appliances (e.g. for cooking, watching TV). The shape of this curve has sometimes been compared to a camel and its humps (Figure 36), hence being referred to as the "camel curve". This curve is predictable, and the ramping requirements are not very steep, thus signifying that overall, generation has been flexible enough to follow this curve.

When VRE penetration, and more specifically solar PV penetration, starts to increase, the shape of the net load curve[33] changes dramatically. Solar PV is mainly characterised by its variability: the sun rises in the morning increasing solar PV generation, which is at its maximum towards the middle of the day, and sets in the evening, making solar PV generation disappear rapidly. With high penetration, solar PV's variability will increase the system's downward ramping requirement in the morning and the upward ramping requirement in the evening. Solar PV might also create an oversupply situation in the middle of the day. This will cause the "camel curve" in Figure 36 to turn into a "duck curve", as shown in Figure 37 (GSES, 2015).

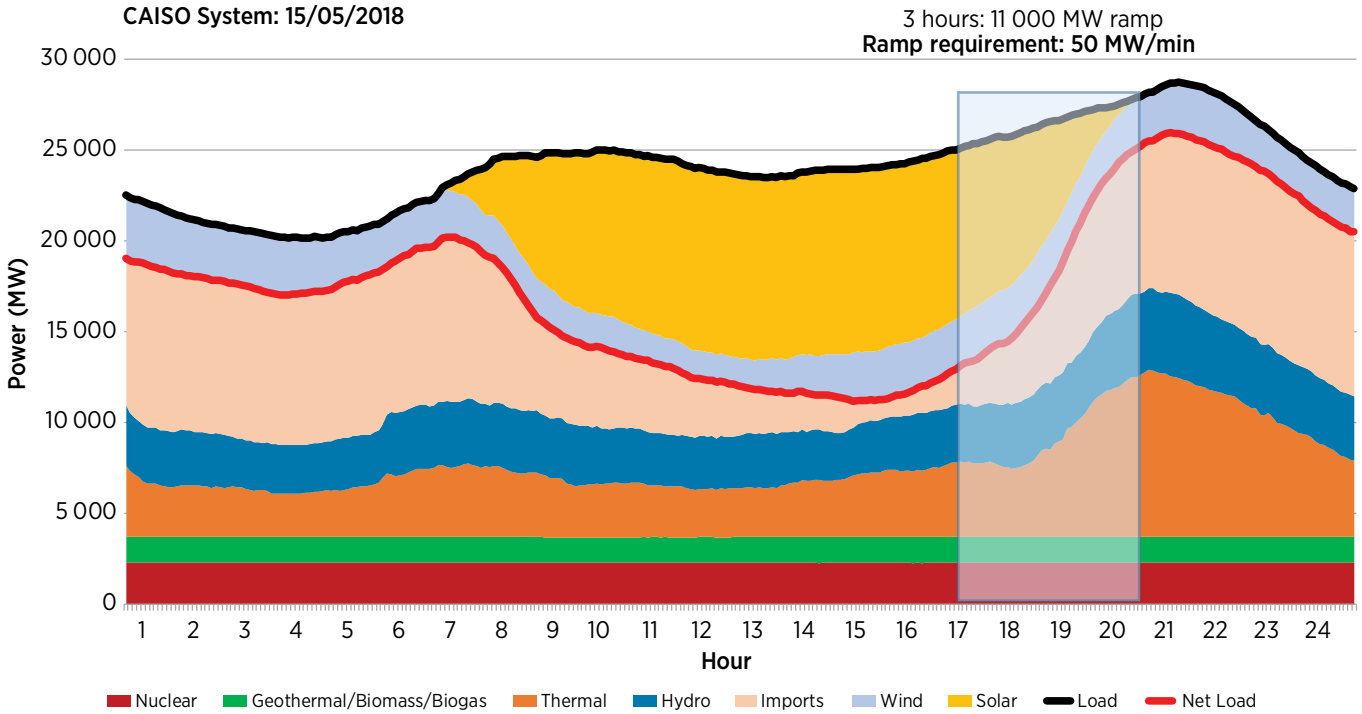
Figure 36: Electricity demand in the Spanish power system, 31 January 2019



Source: Red Eléctrica de España (REE).

33 Net load curve equals system demand minus VRE generation.

Figure 37: Net load curve (duck curve) for the California power system, 15 May 2018



Note: In this case the duck curve is the net load curve (red dashed line) while the camel curve would be the load curve (black line).
Sources: CAISO (2019) for data; figure based on Mashal and Sloane (2018).

The duck curve is already prominent in California, where it first appeared. But it has also been observed in other parts of the United States, such as in the New England states (Roselund, 2018). To manage this net load curve, the grid operator needs a resource mix that can react quickly to adjust production and meet the sharp changes in net demand. In California the first ramp in an upward direction occurs in the morning, starting around 4 am.

The second, in a downward direction, occurs after the sun rises around 7 am when online conventional generation is replaced by supply from solar generation resources. As the sun sets starting around 5 pm, and solar generation ends, the grid operator must dispatch resources that can meet the third and most significant daily ramp, which requires around 11 000 MW of generation to ramp up or start up in only 3 hours. This implies a system with upward ramping capability of 50 MW/minute and therefore a very flexible power system.

2. Flexible ramping as a solution

Clearly, the duck curve can pose a reliability issue and system operators need to find a solution that helps to flatten this curve. Solutions such as peak-oriented renewables, electric water heater controls, demand response or energy storage systems have already been proposed in the literature to "teach the duck to fly" (Lazar, 2016).[34]

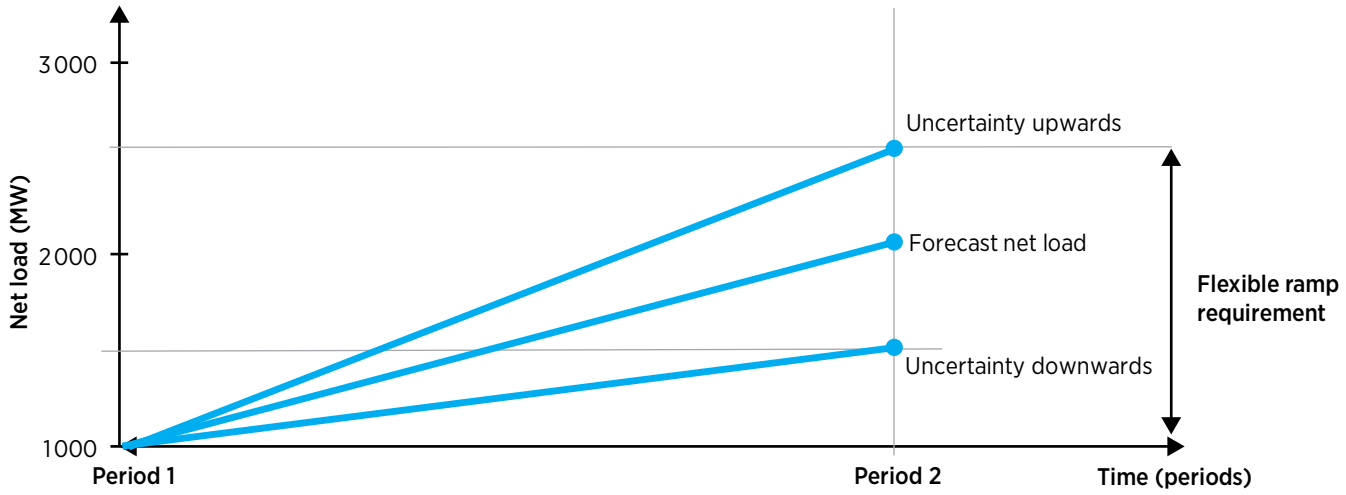
All these solutions provide technical flexibility to the system and help meet the significant ramp requirements of the duck curve. Energy storage, given its capabilities to quickly absorb and discharge energy, could be one of the best solutions to flatten the duck curve.

However, to incentivise the deployment of energy storage, these technologies must be able to participate in electricity markets through adequate market flexibility. For this reason, some independent system operators (ISOs) in the United States have already implemented what has been referred to as the flexible ramping product (FRP), which allows the ISO to procure enough ramping capability in the system and avoid any power imbalance that the high ramping requirements of VRE, mainly solar PV, could cause.

The FRP is an ancillary service and usually has two separate products, one for upward ramping called flexible ramping up (FRU) and another for downward ramping called flexible ramping down (FRD). The product is defined as taking net load variation into account considering ramping requirements of both demand and VRE, and then reflecting the uncertainty of ramp forecast. This last component, like reserve requirements in some power systems, attempts to account for forecast errors in demand and VRE profiles. Figure 38 shows an example of what would be the ramping requirement of the FRP given a net load curve and its forecast uncertainty.

34 In Lazar (2016) the author uses this metaphor to refer to flattening the duck curve.

Figure 38: Ramp requirement calculation for the FRP



To calculate the ramping requirement in Period 1, the operator has three points in Period 2 that correspond with the forecast (expected) net load in the next period and the uncertainty of this net load, being higher or lower. In the example presented in Figure 37, the FRP requirement is only flexible ramping up; however, if the uncertainty downwards had been lower than the net load in Period 1 (e.g. 500 MW), there would also have been a flexible ramping down requirement. As for the price of this ancillary service, it is usually the marginal price of the ramping requirement constraint and signifies the amount of money the ISO would need to pay to procure an additional MW/minute of ramp for the next interval (Wang and Hodge, 2017).

The best-known ISO with FRP in place is the California Independent System Operator (CAISO). This product was implemented in November 2016 and uses the 15-minute and the 5-minute markets to procure the service (CAISO, 2015). Apart from CAISO, the Midcontinent Independent System Operator (MISO) has also implemented the FRP under the name of ramp capability product (MISO, 2016).

3. Impact of flexible ramping on storage deployment

The innovative market product presented in the previous section, and already implemented by some system operators, can incentivise the deployment of flexible resources such as energy storage systems, as it will suppose an additional revenue stream that can make these projects economically feasible. In other words, the FRP monetises the fast ramping capabilities of energy storage systems, allowing these resources to earn money from it. The introduction of this ancillary service in some markets could therefore lead to the deployment of energy storage technologies.

For instance, California is fostering the deployment of energy storage systems, aiming for 1.3 gigawatts (GW) of newly installed storage by 2020 as per the requirement of the California Public Utilities Commission (California Energy Commission, 2018). Since 2016 a total of 80 MW of new battery storage systems have been installed in CAISO yielding a total of around 150 MWh, including the largest Li-ion facility in North America at the time (30 MW/120 MWh), located in El Escondido and owned by San Diego Gas and Electric (Davis, 2018).

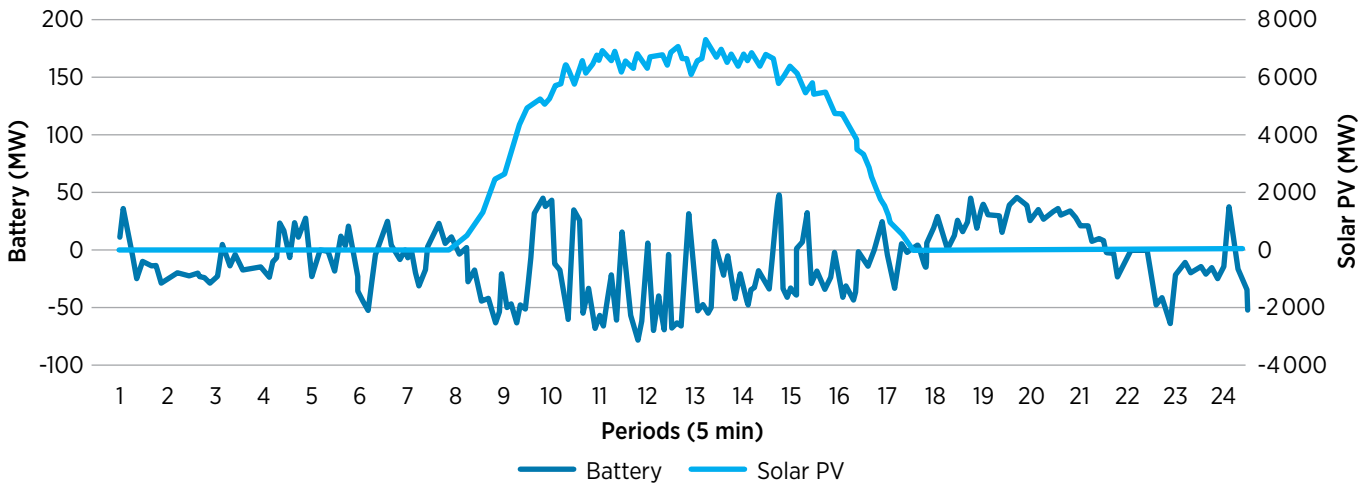
In the long-term horizon, the AES Corporation is planning to install the largest battery storage system in the world at the AES Alamitos Energy Center. The project will consist of a battery system with 300 MW and 1 200 MWh, with the first 100 MW expected to be online by 2020 (AES, 2018). Therefore, enabling market flexibility with the development of new products can give investors the incentive to deploy these technologies.

Electric vehicles (EVs) could also be a resource that provides flexible ramping to the power system, if smart charging is enabled. However, if EVs cannot charge smartly, usually referred to as uncontrolled charging, then they could pose a risk to the system's reliability because they would increase the evening ramp, creating a very steep duck curve. Hence, the deployment of smart charging is of utmost importance to unlock the flexibility of EVs.

4. Storage providing flexible ramping

Battery storage systems are already providing flexible ramping in California. The CAISO, on its website, monitors the dispatch of some of the installed batteries in real time. While these figures do not show clearly which services the batteries are actually providing, they help to see how battery operation responds to market signals and how batteries interact with high solar PV production. Figure 39 shows the solar PV and battery dispatched on 20 December 2018 in the CAISO system (CAISO, 2019).

Figure 39: Solar PV and battery dispatch, 20 December 2018, CAISO system



Analysing the interplay of solar PV with batteries is not easy with the data provided by CAISO alone. The batteries likely provide flexible ramping, energy arbitrage (see case "Energy arbitrage"), operating reserves (see case "Operating reserves") and possibly other services at the same time, which confirms that one use can act as a trigger for the deployment of storage. Once deployed, storage maximises its revenues by providing multiple services at the same time. Additionally, the amount of batteries deployed today is very low compared to demand peak and the effect of them in system dispatch is yet to be prominent. Once all the planned storage projects are in place (1.3 GW by 2020), flexible ramping product provision could be analysed in more detail. Figure 40 shows an example of the expected effect on the duck curve of storage participating in the flexible ramping product.

Apart from this, some research papers have studied optimal strategies for batteries to provide flexible ramping products. In Hu et al. (2018) the authors study how a battery aggregator could better provide different services, including FRP, to maximise its monetary benefits. Going one step further, Kim et al. (2017) study the capability of EVs to provide FRP and find that they could reduce the operating costs of the system, especially if there are highly variable VRE resources in the area of applicability.

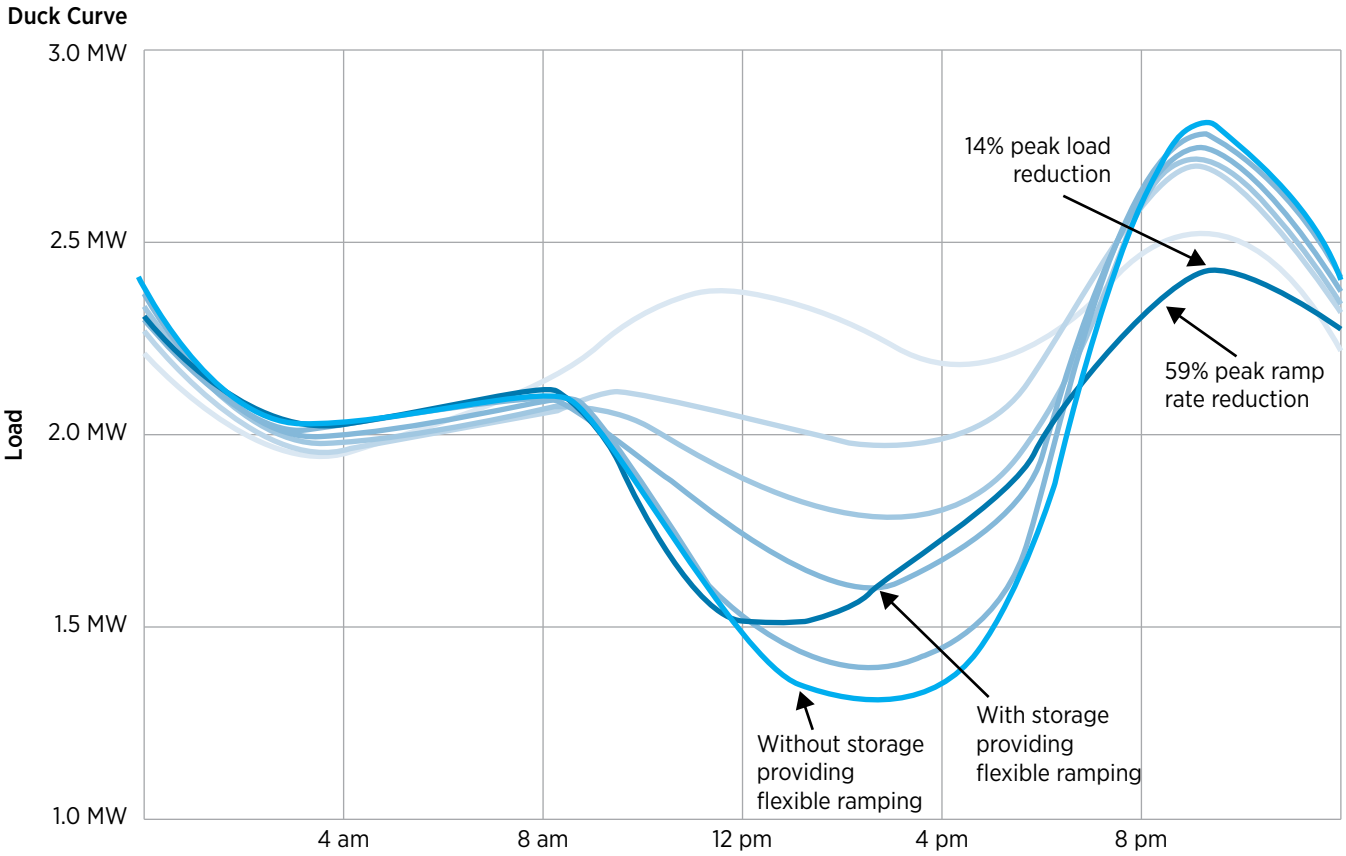
5. Conclusions (Case 2: Flexible ramping)

In power systems with high VRE penetration the load curve is being reshaped by the variability and uncertainty of these resources. When specifically solar PV penetration is very high, the load curve is reshaped conforming to what is known as the "duck curve", which was first prominent in the Californian power system. This curve is characterised by very high ramp requirements that need to be met by other resources in the system. Flexible technologies such as energy storage are suitable for meeting these ramp requirements and flattening the duck curve. A market product to incentivise the deployment and participation of storage could result in storage flattening the duck curve.

CAISO has developed a product that seeks to procure the necessary flexible ramping to meet net load ramps in every period. The deployment of storage in the CAISO area has been growing, and by 2020 the system is required to have 1.3 GW of total installed storage capacity. Whether or not storage is providing flexible ramping is hard to assess. However, once storage deployment reaches a high enough level, the effect shown in Figure 40 can be expected to occur.

Electric vehicles can either create a steep duck curve through uncontrolled charging or provide flexible ramping through smart charging

Figure 40: Impact on the duck curve of energy storage providing flexible ramping: the example of one 3 MW feeder



Note: Figure shows impact for one feeder, not the entire CAISO system.
Source: Sunverge (2015).

6. Further reading

For more on ancillary services, see the Innovation Landscape brief (2019), "Innovative ancillary services".

Case 3: Energy arbitrage

1. The role of energy arbitrage in VRE integration

Energy arbitrage essentially comprises storing electricity at times when energy is plentiful and inexpensive, and discharging it to the grid when it is scarce and most expensive. As price differentials reflect system-wide or local scarcities or excesses, providing arbitrage services can often at the same time translate into providing other benefits, such as reducing the need for peaking plants (see case "Reducing peaking plant capital costs"). This results from providers discharging when prices are high due to scarcity and relieving the transmission system of congestion (see case "T&D investment deferral") by discharging energy in specific nodes or zones in the system when prices there increase due to the need for redispatch. Another benefit that results from providing energy arbitrage services is that of reducing VRE curtailment when generation surpasses demand.

According to IRENA's "Adapting market design to high shares of variable renewable energy" report (2017b), liberalised electricity markets require appropriate adaptation to support higher shares of VRE and distributed power generation. A common way of performing energy arbitrage in electricity markets is by buying or selling electricity in day-ahead markets and then taking an offset position in intraday and real-time markets. This allows electricity market participants to exploit the differences between day-ahead and real-time market prices.

VRE generation suppresses electricity prices since it has a negligible marginal cost. Consequently, at high shares of VRE, prices will often be low when there is a lot of VRE generation. Therefore, there are several potential benefits from storing VRE generation for later use:

- To increase revenue for the VRE project owner by shifting VRE energy from hours with abundant VRE generation and low prices to hours with limited VRE generation and high prices. Energy storage can additionally reduce VRE curtailment due to overgeneration or negative prices.[35]
- To reduce or eliminate VRE curtailment due to transmission bottlenecks.
- To increase fuel savings and reduce carbon emissions for general societal benefit due to reduced curtailment.
- To avoid price spikes when scarcity would otherwise occur, thus flattening the price curve.

When VRE generation is available, it pushes other types of resources out of the merit order, reducing the marginal cost of supplying electricity and, in turn, reducing the revenues received by all supply resources. By shifting VRE generation to hours with high residual demand,[36] storage allows VRE to supply energy during hours with higher marginal costs, increasing revenues for VRE by increasing their capture price.[37] Solar tends to depress its own capture price, with an effect called revenue cannibalisation. Hence, storage has a much higher value for solar than wind in this application. It also pairs better with solar because the time periods of VRE saturation are diurnal, whereas for wind they can be days or even a week at a time. This tends to be the opposite for other applications such as reserve provision (see case "Operating reserves"), as the contribution of solar to the reserve requirement is significantly lower than that of wind.

Similarly, when VRE generation is present during times of low electricity demand, the grid operator will instruct thermal resources – with non-zero marginal costs – to ramp down, sometimes close to their technical operating lower limits. Such operations put the thermal resources at operating points lower along the heat rate curve, reducing their fuel efficiency. By shifting VRE generation to high-demand hours, storage would allow the thermal resources to operate at more efficient operating points and avoid thermal cycling, saving fuel and reducing carbon emissions.

Due to technical constraints, power system stability cannot be maintained in a cost-effective way in large power systems using inverter-based VRE generation alone. Consequently, grid operators sometimes have to curtail VRE generation to maintain reliable system operation. In the presence of storage, the minimum amount of synchronous generation can be maintained while VRE is stored for later use (effectively a security-driven arbitrage).

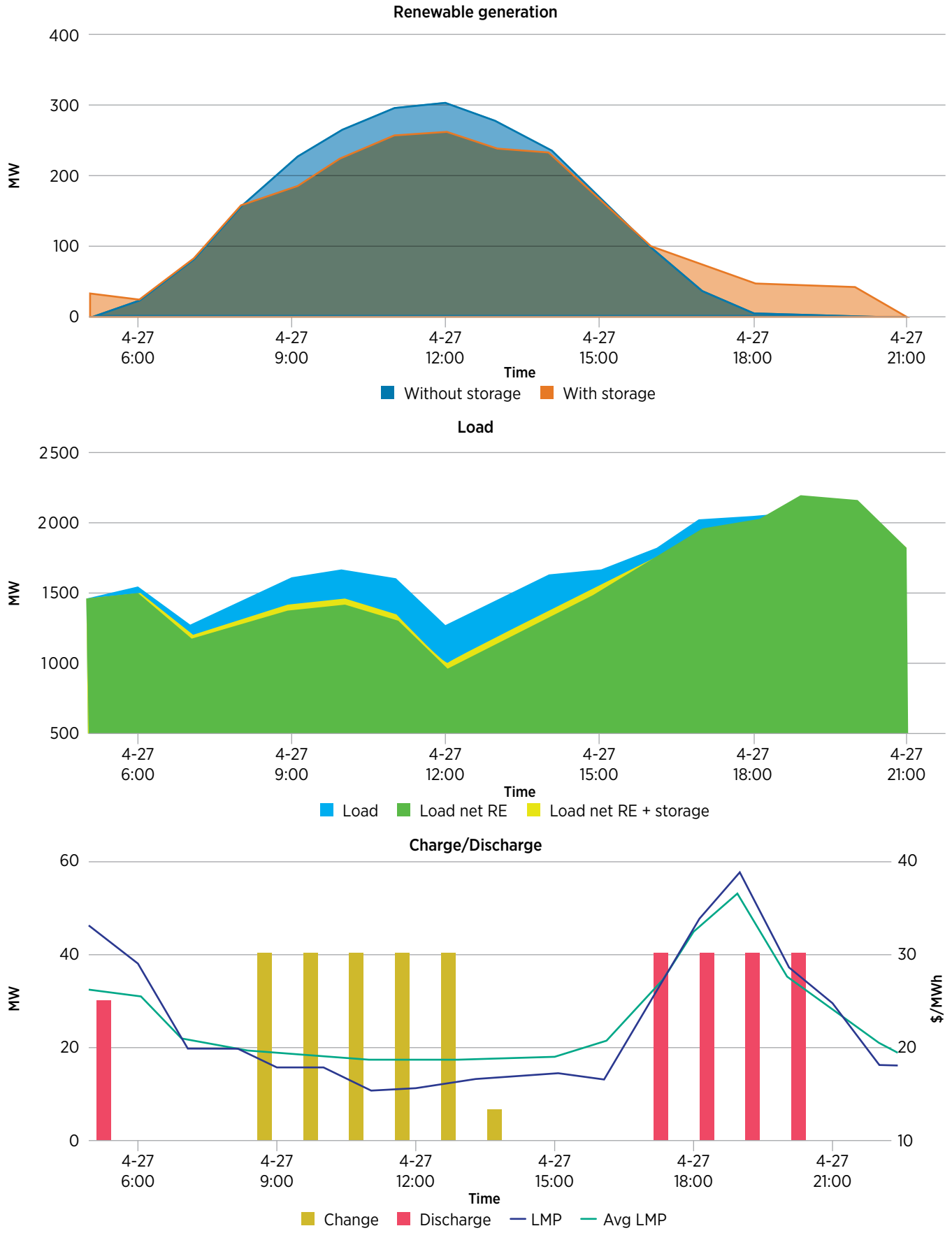
In Figure 41, the blue area (partially obscured by the "With storage" orange area) represents the output of solar PV without energy storage, whereas the orange area represents the combined output of energy storage and solar PV. Part of the VRE production between hours 9 and 14 is stored and used to serve the load between hours 16 and 21. The bottom graph illustrates that charging takes place when the electricity price (locational marginal price, LMP) is low, while the price is high when storage discharges into the grid.

35 Negative prices can appear in low net load periods, during which inflexible generators may find that continuing to generate is more cost effective than shutting down the power plant.

36 Demand minus VRE generation.

37 Defined as the revenues "captured" by a specific generator or group of generators, obtained by multiplying its generation in each market interval by the market price in that interval.

Figure 41: Example of VRE-shifting use: renewable generation and net load with and without energy storage, and charging and discharging profile of energy storage



Notes: MW = megawatt; MWh = megawatt hour; RE = renewable energy, LMP=Locational Marginal Price.

Energy arbitrage is considered by many as the main application for energy storage. Even so, a business case would be hard to make with arbitrage as the sole application for storage (Lew, 2016). Firstly, most marginal plants in a generation mix are gas plants and low natural gas prices do not frequently drive the high price spreads that create energy arbitrage opportunities. Secondly, forecast errors generally tend to be worse when prices are volatile (i.e. when energy arbitrage opportunities are best), making bidding unpredictable.

Price extremes are driven by severe forecast errors such as wind under- and over-forecasts in electricity systems with significant penetration of wind energy. To make the best use of energy arbitrage, storage operators should be able to predict/anticipate when and in which direction large forecast errors will occur, and this is definitely very challenging. The Western Wind and Solar Integration Study (GE Energy Consulting 2010), prepared by GE Energy for NREL, shows how high shares of solar and wind can impact energy arbitrage. The study demonstrates how increased penetration of wind has changed the timing of price spikes and how severe forecast errors drive price extremes.

A major challenge in using storage to integrate high shares of wind is that high- and low-priced hours generally tend to be related to high forecast errors. Hence, the storage operators' forecasts need to be better than the wind forecasts to benefit from that price spread (Lew, 2016). However, given the flexibility that some storage resources (e.g. batteries) possess, they are able to make the most of price differentials among day-ahead, intraday and real-time/balancing markets, profiting by rapidly responding to imbalances and price volatility.

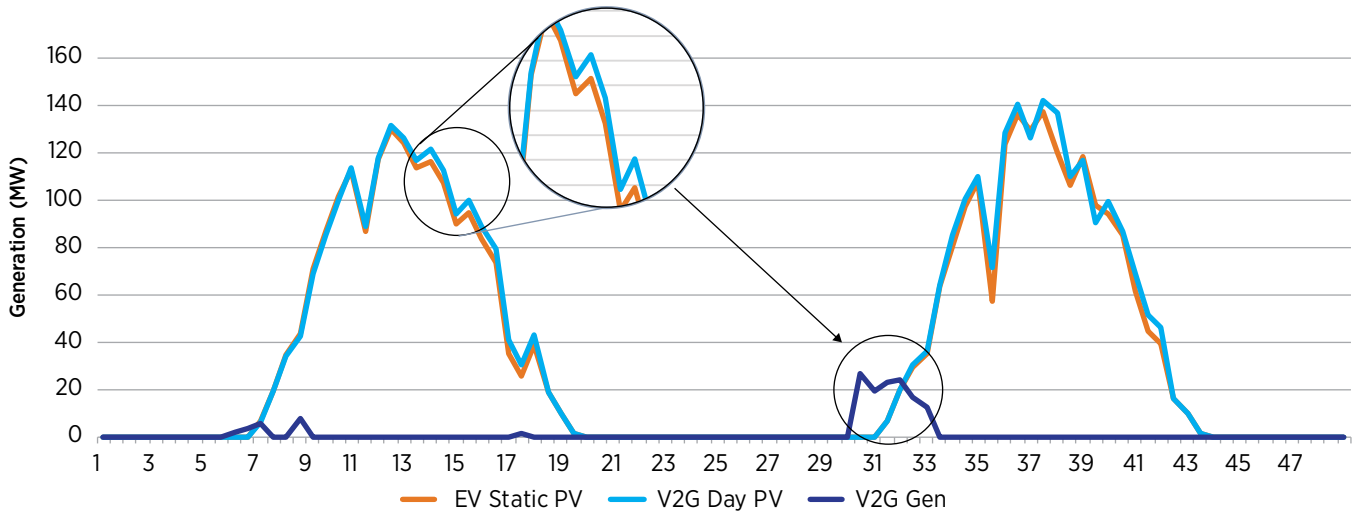
Unlike wind, solar is much more predictable and can thus be integrated better with storage, as operators know when to charge and discharge. Furthermore, with higher shares of solar, large amounts of energy can be shifted from the peak central hours (when prices are lower) to hours when demand is higher, such as evenings (when prices are higher). By doing so, storage operators can create a strong price-flattening impact using storage, with reasonable monetised revenues. By contrast, wind can be present throughout the day depending on the local wind patterns.

Electric vehicles (EVs) are another option to provide time-shifting of load and flexibility to the grid. EVs can be a key enabler for VRE integration and can essentially act as grid-connected storage systems when connected to the grid through a charger. Hence, they are able to provide a broad number of services to the system. If connected through bidirectional chargers (i.e. vehicle-to-grid [V2G]), EVs not only charge using electricity from the grid, but also discharge back to the grid, and by doing so become capable of providing ancillary services in addition to energy arbitrage, stacking revenues from both (Taibi, Fernández del Valle and Howells, 2018).

In the V2G system, EVs perform energy arbitrage by shifting energy from peak hours of the day to evening and early morning hours. This can be seen in Figure 42, which shows how EVs perform energy arbitrage, where EV Static PV represents EVs modelled as a static profile and V2G Gen represents the energy that is discharged from the EV to the grid. The figure also shows how, with V2G, higher shares of PV can be absorbed and then used subsequently (i.e. evening or early morning of the next day).

Performing arbitrage with EVs in the V2G system, however, could increase battery degradation, dependent on its operation (e.g. number of cycles, speed of discharge and depth of discharge). Adding a constraint that accounts for battery degradation is advisable when analysing the optimal arbitrage strategy.

Figure 42: EVs providing energy arbitrage



Source: Taibi, Fernández del Valle and Howells (2018).

2. Storage providing energy arbitrage

Pumped hydro energy storage (PHES) is essentially a utility-scale hydroelectric energy storage system that consists of two reservoirs or basins, one located at a higher level or elevation than the other. When electricity prices are low or excess electricity is available, water is pumped to the upper reservoir where it is stored. When prices are high, the water flows back down to the bottom reservoir through turbines and by doing so generates electricity. Hence, PHES has been traditionally used to provide energy arbitrage as well as ancillary services (Rehman, Al-Hadhrami and Alam, 2015).

One of the advantages of using PHES compared to batteries is that the system has a much longer lifespan. With appropriate maintenance PHES has a very long lifetime. Furthermore, PHES generally has a much higher energy-to-power ratio compared to batteries, especially when associated with large reservoirs. Some of the drawbacks of PHES compared to battery storage systems include its higher environmental impact and footprint, the requirement for a special geographical area to build it (very site-specific, while batteries can be deployed anywhere – allowing them to maximise the value to the system), lower efficiency (around 80% while Li-ion batteries can exceed 90%), and long construction time (years compared to months).

The largest Li-ion battery in the world at the time it was deployed, known as the Hornsdale Power Reserve, is located at the Hornsdale Wind Farm in Jamestown, South Australia (Figure 43). Deployed by Tesla and managed by Neoen, with a total capital cost of AUD 90 million, the battery has a storage capacity of 129 MWh and is rated at 100 MW discharge with 80 MW charge. The battery has the same 275 kilovolt grid connection point as the wind farm, which consists of 99 turbines and has a capacity of 315 MW. Of the battery's 129 MWh capacity, 119 MWh is used for energy arbitrage and 30 MW of the discharge capacity is used by Neoen for commercial operation.

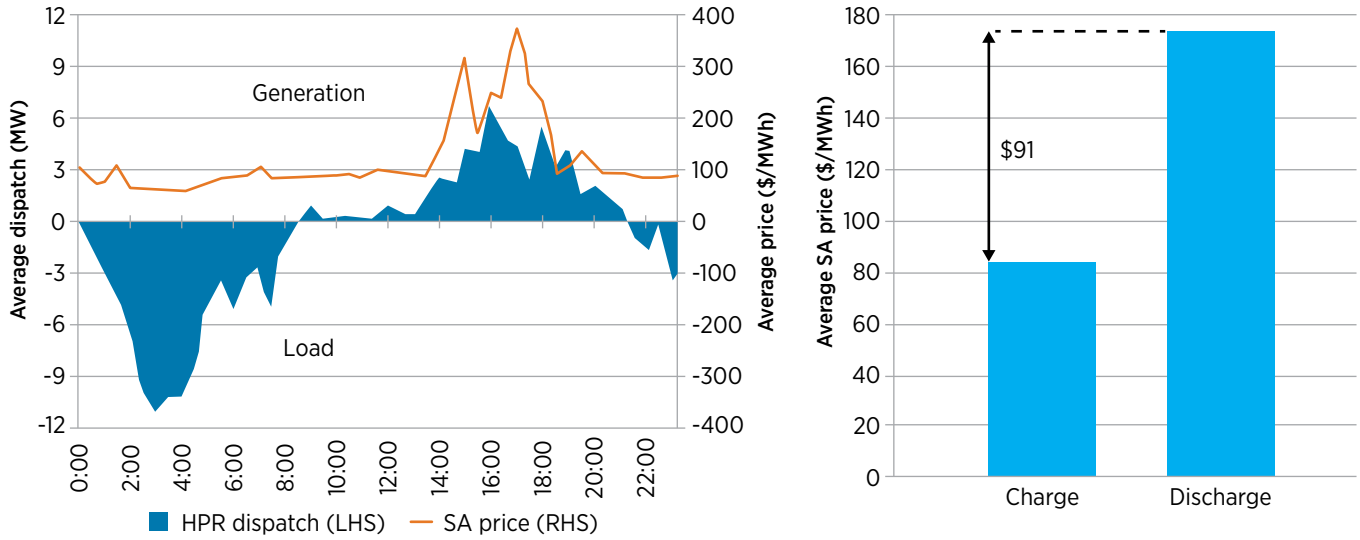
Since its deployment in 2017, the battery system has been providing various services such as energy arbitrage and regulation, and contingency frequency control ancillary services (FCAS) (Aurecon Group, 2018). Moreover, according to the Australian Energy Market Operator (AEMO) the energy arbitrage service has been generating revenues, and the average daily dispatch shown in Figure 44 clearly demonstrates how the Tesla battery has succeeded in making money through energy arbitrage. As can be seen from the graph, the battery is charged (load) during the early hours of the day when prices are low and is discharged (generation) during evening hours when prices are high. The battery system generated revenue of about AUD 29 million in 2018, exceeding the expectations and surprising everyone including its owner and operator Neoen.

According to Neoen, the revenues consisted of AUD 4.2 million in fixed revenue (for 10 years) from the South Australian Government, and about AUD 24 million generated from FCAS and energy arbitrage. AEMO states that between December 2017 and March 2018, the Tesla Powerpack system was charged or dispatched as a load for 38% of that period, with a total of 11 gigawatt hours (GWh). During that same quarter, the battery was discharged for 32% of the time and a total of 8.9 GWh. The figure also shows that the average price arbitrage between the average charge and discharge prices is approximately AUD 91/MWh. The Hornsdale Power Reserve has already taken a 55% share of the FCAS market in South Australia and has reduced ancillary prices by 90%, stacking arbitrage revenues with operating reserve revenues (see the case "Operating reserves").

Figure 43: Hornsdale Power Reserve in South Australia

Source: Tesla

Figure 44: Hornsdale Power Reserve average dispatch price and charge and discharge prices



Source: Vorrath and Parkinson (2018).

Furthermore, the battery system has proven itself numerous times since its deployment, providing grid services as well as backup power. The most remarkable example is when on 14 December 2017 the 1 680 MW Gladstone coal-powered station's unit failed and the Tesla battery was able to supply backup power of 7.3 MW in less than 1 second. Overall, the Hornsdale Power Reserve is a clear example of storage providing energy arbitrage as well as grid services.

The El Hierro Project, managed by Gorona del Viento, is a first-of-its-kind wind-hydropower plant located on El Hierro Island, Canary Islands (Figure 45). The island relies heavily on conventional diesel fuel and is now making the transition to a fully renewables-powered system. The objective of this project is to supply the entire population of the island with 100% renewable energy (Garcia Latorre, Quintana and de la Nuez, 2019). Deployed in 2014, the wind-hydropower system is composed mainly of the following: an upper reservoir, a bottom reservoir, a wind farm and a hydroelectric power station. The upper reservoir or tank is located on the top part of the island in a natural volcanic basin and has a capacity of 380 000 cubic metres (m^3). The bottom reservoir is situated near the hydroelectric power station and has a storage capacity of 150 000 m^3. The wind farm is composed of five 2.3 MW wind turbines, having a total capacity of 11.5 MW. The hydroelectric power station consists of four 2.83 MW Pelton groups, having a total capacity of 11.32 MW. In addition to supplying households with electricity, the wind turbines supply energy to several pumping stations to retain water in the upper reservoir. The water in this reservoir is a way of storing energy before it slides towards the lowest part of the island by gravitational force, powering the hydroelectric plant.

According to Endesa, which holds 30% of the project's shares, the benefits during the next 20 years of the project include a reduction of 6 000 tonnes of diesel and 19 000 tonnes of CO2. Each year the effectiveness and benefits of this project improve and for the first time in August 2015, for four consecutive hours, the El Hierro plant generated all of the island's electricity from 100% renewable energy. Furthermore, since then the period of achieving 100% renewable energy generation has been extended: the plant generated 100% renewable electricity for a period of 892 hours in 2017 and 1 450 hours in the first half of 2018. The wind-hydropower plant is now capable of covering 75% of the annual electricity demand of the island with renewable energy resources, often hitting peaks of 100% (Gorona del Viento, 2019).

The El Hierro project is one of the few examples of PHES being deployed to enable a 100% VRE share (wind, in this case) for extended periods of time. It can also be seen as providing energy arbitrage by pumping water to the upper reservoir when wind generation exceeds demand and releasing it back to the bottom reservoir to generate electricity through turbines when demand is higher than wind generation. This is again a case of multiple uses, where enabling high shares of VRE in an off-grid context (see case "Enabling high shares of VRE in an off-grid context") is performed by pumped hydro making best use of low-priced electricity from wind to displace high-priced electricity from oil, which is a form of arbitrage. At the same time, according to the Spanish electrical network (REE), the power plant was able to supply 100% renewable energy for up to 18 days in a row, with a renewable share of 46.5% in 2017, hence aiding El Hierro's transition from a diesel-based power system to a fully renewable energy power system.

Figure 45: Commissioning of the wind-hydro system in El Hierro

Source: IRENA/E. Taibi

3. Conclusions (Case 3: Energy arbitrage)

As the share of VRE increases to significant levels, now more than ever electricity markets need to match real-time supply and demand. Considering the high unpredictability of solar and wind, this is very challenging. One viable solution is to use storage systems to provide flexibility and make the grid more efficient. Storage systems provide several value streams, one of which is energy arbitrage, which consists of charging the storage system with VRE when electricity is inexpensive and discharging it to the grid when it is expensive.

A major challenge for storage operators is that forecast errors, which drive price extremes, usually tend to be worse when arbitrage opportunities are best. Hence, to make the best use of energy arbitrage, the ideal would be for operators to be able to predict in advance when severe forecast errors will occur. Due to a higher predictability than wind, solar can be integrated better with storage systems and be used to shift large amounts of energy from the central hours of the day to flatten the price curve.

Energy arbitrage on its own, however, may not be a sufficient use, as it would require a large price delta between peak and off-peak differentials for longer periods of time during the day, week or month, and because with increased arbitrage, the price delta decreases. Given that arbitrage may not be a sufficient use on its own because it saturates with growing storage penetration, a viable case requires stacking of revenues from arbitrage with provision of grid services.

This chapter covers the role of energy arbitrage in VRE integration and includes real-life scenarios where storage has provided arbitrage along with the various economic benefits that come with it. Furthermore, the chapter also discusses the challenges in integrating high shares of VRE into the grid and how EVs with V2G are an alternative option for providing flexibility and arbitrage by shifting energy from peak midday generation hours to evening hours when demand is higher.

4. Further reading

Increasing time and space granularity in electricity markets is closely related with the provision of energy arbitrage. Both concepts are among 30 power system innovations examined in IRENA's Innovation Landscape study. For more, see:

IRENA (2019), "Innovation Landscape Brief: Increasing time granularity in electricity markets", International Renewable Energy Agency, Abu Dhabi.

IRENA (2019), "Innovation Landscape Brief: Increasing space granularity in electricity markets", International Renewable Energy Agency, Abu Dhabi.

IRENA (2019), "Innovation Landscape Brief: Utility-scale storage", International Renewable Energy Agency, Abu Dhabi.

Case 4: VRE smoothing

1. Challenge – VRE output fluctuation

VRE is characterised by its variability and uncertainty. This means that VRE resources do not have a controllable fixed output, but a fluctuating non-dispatchable one. In the case of solar PV, power fluctuation is mainly caused by cloud movements. If the sun is shining and the PV panel is producing at its maximum rated capacity and a cloud suddenly covers the sun, electricity production will suffer a sudden drop that will increase again once the cloud is gone. In the case of wind, power fluctuations are due to the variability of wind speed.

Such power fluctuations can diminish power quality and reliability and could pose a challenge to grid system operators, who need to maintain grid stability by balancing electricity demand and supply. Power fluctuations then produce instability in voltage and frequency. However, power fluctuations usually decrease as the size of the solar PV or wind plant grows and as the geographical dispersion of VRE resources in the power system increases. Therefore, in interconnected power systems with high geographical dispersion of VRE, while individual wind turbines or solar PV panels might suffer such fluctuations, aggregated VRE sources result in a combined smooth profile. In small isolated power systems, however, given their small territory and lack of interconnection these power fluctuations could affect power system reliability and security. As an issue that must be taken care of, a solution must be found to smooth the VRE production profile.

Evidence of how these fluctuations can affect small isolated power systems is provided by the minimum technical requirements that the Puerto Rico Electric Power Authority (PREPA) set in 2012 for the connection of solar PV and wind to the power system. Among its requirements, the authority set a 10% per minute ramp rate limit on VRE based on nameplate capacity (Gevorgian and Booth, 2013). Thus, if the nameplate capacity of the solar PV plant is 1 MW, the maximum allowed variation in 1 minute would be ±0.1 MW.

Another real-life example is the case of Hawaii, in the United States, where the Hawaiian Electric Company (HECO) limited the ramp of 25–50 MW projects at 2–3 MW/minute (Gevorgian and Corbus, 2013).

In both cases, if the power output from VRE goes beyond these ramp limitations then the resource would have to be curtailed in order to smooth the profile, which is not the optimal solution. The optimal choice would be to smooth the VRE profile while avoiding curtailment.

2. Solution

A solution envisaged to smooth solar PV and wind production is energy storage, given its capabilities to rapidly respond to changes. Electricity storage, coupled with VRE resources, would be able to smooth the fluctuations of solar PV and wind, avoid frequency and voltage fluctuations, avoid VRE curtailment and improve the system's reliability. This is referred to as VRE smoothing.

Assume that there is a ramp limitation in the system r_Max and a VRE power variation from period t to period t+1 called ΔP. Initially the power system will try to absorb the entire ΔP, however if ΔP exceeds the maximum ramp, part of this energy would have to be curtailed (if ΔP is positive) or substituted by other sources like diesel generators (if ΔP is negative). What energy storage will do in this case is to absorb the excess energy that otherwise would be curtailed or discharge the stored energy in order to avoid fossil fuel-based generation or even loss of load. This process is depicted in Figure 46, which shows how VRE production is smoothed out, given the ramp requirements of the system, by either curtailing the generation or absorbing it by storage charging (in the case of downward ramping, this would be either producing loss of load or discharging energy from storage).

Figure 46: VRE smoothing process in a period where the maximum allowed ramp is exceeded by the VRE resource

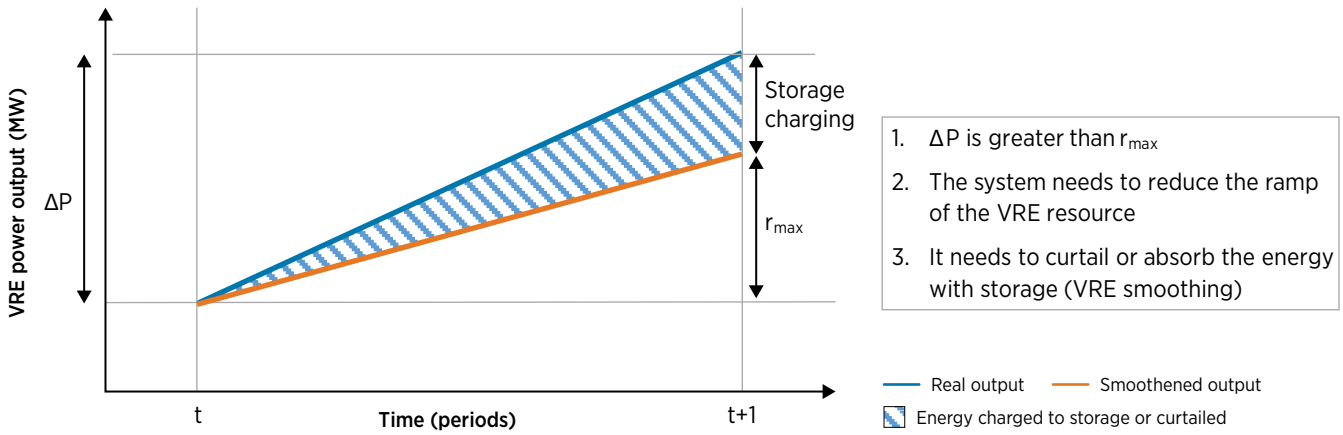


Figure 47: Batteries at the Prosperity energy storage project in New Mexico

Source: PNM

Figure 48: Wind power plant in Maui, Hawaii

Source: Shutterstock

3. Storage deployment driven by VRE smoothing

Some energy storage projects have already been deployed mainly to provide VRE smoothing. For example, in New Mexico the Public Service Company of New Mexico (PNM) installed the Prosperity energy storage project with two goals: to provide smoothing to a solar PV farm and to provide energy shifting. This project is composed of 500 kilowatts (kW) of solar PV panels and two types of battery: a 0.25 MW/1 MWh advanced lead acid battery system for energy shifting and a 0.5 MW/0.35 MWh advanced lead acid battery system with integrated capacitors for power smoothing (Roberson et al., 2014) (Figure 47).

Hawaii has also installed batteries for wind smoothing. For example, NEC Energy Solutions provided a Li-ion battery for wind smoothing close to the Auwahi 21 MW wind farm on the island of Maui (Figure 48). The battery in this location has a capacity of 11 MW/4.3 MWh. The specific technology used is lithium iron phosphate because of its durability and safety for the smoothing application, and because the technology has been used successfully before in many locations around the world (IRENA, 2015b). A further example is the Kaheawa wind farm, also located in Maui. The wind farm has a total installed capacity of 51 MW, which was coupled with 11.5 MW/21 MWh of advanced lead acid batteries mainly to provide VRE smoothing (Roose, 2018).

In 2018 an agreement was signed between the plant owner, TerraForm, and the battery manufacturer, Younicos, to replace the lead acid batteries with Li-ion ones given their higher usable capacity and operational lifetime (Power World Analysis, 2018)

Other examples include the French islands. In May 2015 the French government launched the tenders known as CRE3 RFP, intended to develop solar projects with storage on the French islands. Among the specifics of these tenders, the storage had to be deployed to smooth the PV curve to avoid having to manage variability and uncertainty. More specifically, the storage had to provide a precise, smooth morning ramp-up from all solar systems, a stable plateau during the central hours of the day, and a symmetric ramp-down in the afternoon. The tender awarded a total of 52 MW of solar and storage projects in Corsica (18 MW), Guadeloupe (9 MW), Guyana (5.2 MW), Martinique (11.1 MW) and La Réunion (8.5 MW). These projects were awarded a weighted electricity price of EUR 204/MWh. However, in a subsequent auction where 72 MW were awarded, this price was reduced to EUR 113.6/MWh. This made the PV systems fully dispatchable, avoiding any issue related to variability and uncertainty, although probably at a higher cost than necessary. This can be seen as an upper bound in terms of the cost of transforming PV systems into fully predictable generators, with smooth output and limited ramps.

4. Storage providing VRE smoothing

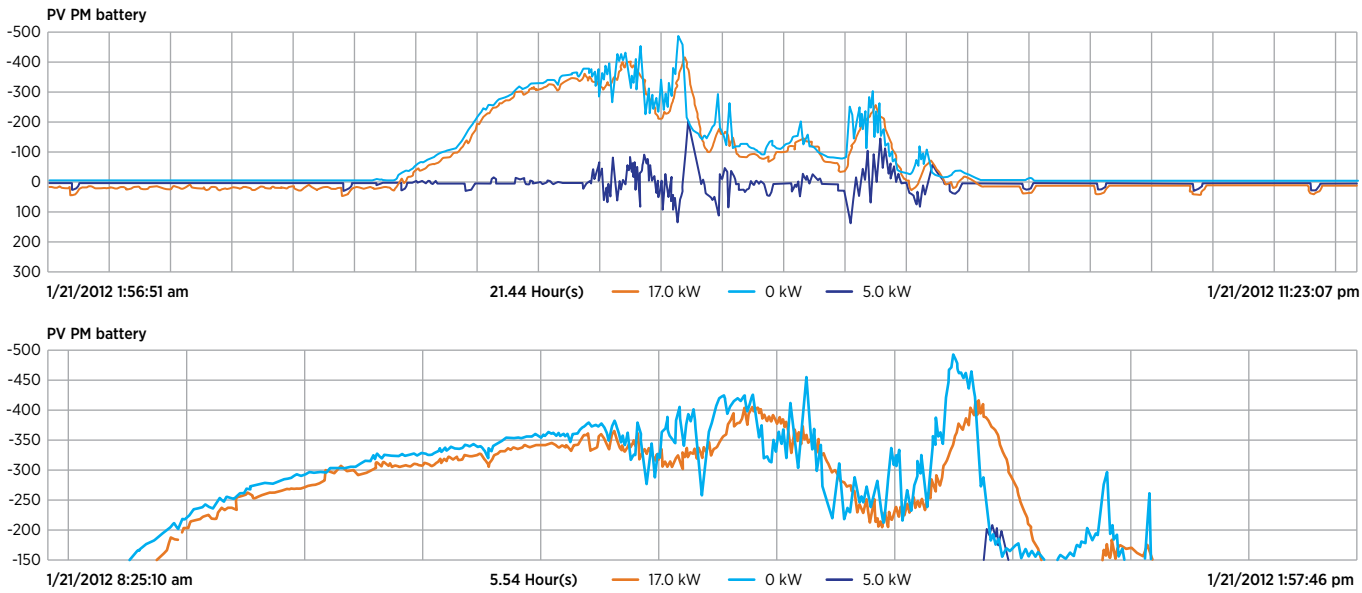
The projects presented in the previous section have been deployed on islands or in small isolated power systems to provide VRE smoothing as a main service. For some of them there is even publicly available information on how to provide this service.

For example, in New Mexico the Prosperity energy storage project uses a smoothing algorithm developed by Sandia National Laboratories that responds to changes in solar output automatically. Figure 49 shows how the battery storage smooths the solar PV profile in this location. The blue line is the raw PV output, the yellow line is the battery output and finally the red line is the smoothed PV profile (battery+solar PV). Significantly, the red line shows much less variability than the raw PV output (blue line) and therefore the battery is correctly providing this service.

Something similar occurs on the French islands with the projects cleared in the CRE RFP tenders, where, as already explained, storage was deployed to provide a precise, smooth morning ramp-up from all solar systems, a stable plateau during the central hours of the day, and a symmetric ramp-down in the afternoon. For example, on the French island of La Réunion a 9 MWh battery was installed together with a 9 MW solar PV plant to provide VRE smoothing. Figure 50 shows how this battery smooths the solar PV profile by fulfilling the requirements explained above.

Figure 50 also shows that with a certain amount of storage coupled with solar PV, the VRE resource is no longer variable, but instead a dispatchable energy source that is completely predictable. Thanks to storage the solar PV ramp is controlled and resource variability is no longer an issue.

Figure 49: Prosperity energy storage project providing VRE smoothing to a solar PV plant



Note: Data from 21 January 2012.
Source: Arellano (2012).

5. Conclusions: (Case 4: VRE smoothing)

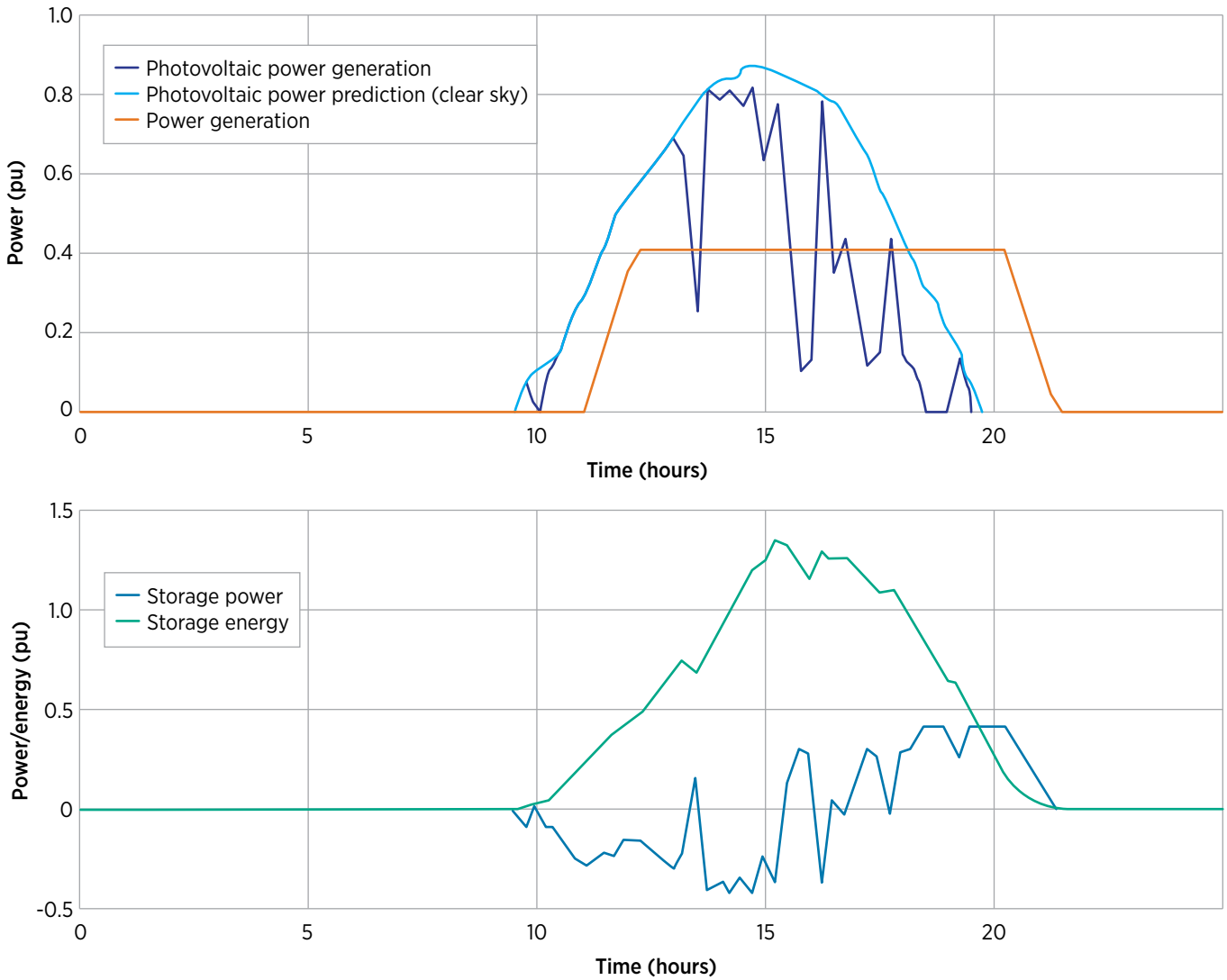
Is VRE smoothing a relevant case for storage today?

The question now is whether VRE smoothing is a relevant reason to install energy storage systems. The straightforward answer is that installing storage only to provide VRE smoothing is not relevant in most applications, although it may have value in certain niche situations. However, this becomes an added value when stacked with other services.

At a utility-scale level, the aggregation of VRE production and demand on the transmission network results in a smooth net load profile thanks to the geographical dispersal of the resources. At the distribution level the aggregation of VRE and demand on distribution feeders also typically results in a smoother net load profile. Smoothing might be required, however, if the individual wind or PV farm supplies a significant share of the electricity in the synchronous area or islanded power system in certain moments of the year. This might make operation of the power system challenging without smoothing the output of the VRE plant, due to highly variable net load.

Therefore, VRE smoothing is relevant only in specific circumstances and the installation of energy storage should not be considered exclusively for this application. Instead smoothing should be considered as one of the value streams from a storage asset that is stacking multiple services (e.g. arbitrage and smoothing). Smoothing the output of VRE is particularly important for island grids, where the alternative source of energy is often the heavily polluting diesel generator. Despite increasing installation of VRE, operators of island grids often need to keep diesel generators online at less efficient operating points to mitigate unforeseen ramps in renewable generation. If such ramps can be managed by energy storage, the operators can better manage the diesel generators, significantly reducing fuel usage and greenhouse gas emissions.

Figure 50: Solar PV smoothing on the French island of La Réunion with a 9 MWh battery



Source: Ingeteam (2016).

Case 5: T&D investment deferral

1. Challenge – Effects on T&D

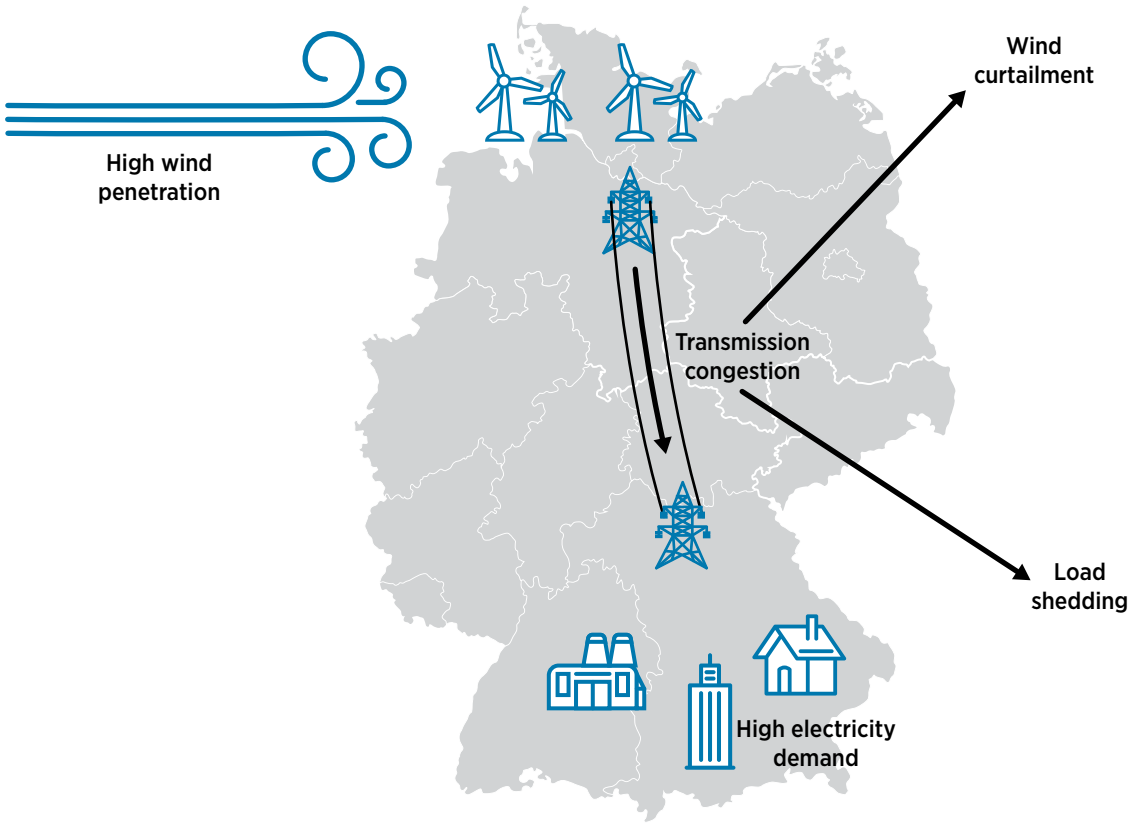
Congestion on transmission and distribution (T&D) networks is one of the main problems that system operators have to deal with to ensure system security and reliability. Congestion management is therefore one of their principal tasks, for which system operators have been using different techniques such as system redispatch, flexible alternate current transmission systems (FACTS) or market flow strategy concepts (Gope, Goswami and Tiwari, 2017).

When the system's VRE penetration is high there is a higher risk of T&D congestion that could threaten the security and reliability of the system, due to the variability and uncertainty of VRE resources. In this situation, system operators are sometimes obliged to resort to VRE curtailment as a congestion management method. However, according to IRENA's definition of flexibility (IRENA, 2018a), VRE curtailment and T&D congestion are both indicators of an existing flexibility issue and a set of solutions must be taken into consideration to achieve the effective grid integration of renewables.

One of the best-known examples of VRE curtailment due to transmission congestion is found in Germany's power system. Two-thirds of the onshore wind capacity, plus all the offshore wind farms, are in the northern part of the country while large industrial consumers are located in the south. The issue that has been experienced for some years is that transmission lines transferring wind generation from northern to southern Germany do not have enough transfer capacity and thus frequently become congested. This results in wind curtailment in the north and the ramping up of expensive and polluting thermal power plants in the south, which overall leads to higher energy prices related to redispatch (Appunn, 2015). This example is illustrated in Figure 51.

The high penetration of VRE can also affect the distribution level in several ways, for example in the case of distributed solar PV. In Palminter et al. (2016) the authors show that the three major concerns of utilities in the United States relating to distributed generation are: a) voltage regulation, meaning distributed generation can raise the voltage beyond acceptable levels, b) reverse power flows that can yield control and protection problems, and c) protection co ordination that might be made difficult by a high penetration of distributed generation. Distribution feeders are characterised by their hosting capacity, which defines how much solar PV can be placed on the feeder before negative effects take place during normal distribution operation. VRE can be then integrated until the hosting capacity is 0, a point at which solutions to increase the hosting capacity must be evaluated.

Figure 51: Transmission congestion between northern and southern Germany



Disclaimer: Boundaries shown on this map do not imply any official endorsement or acceptance by IRENA.

2. Solutions to integrating VRE on T&D networks

Different solutions have been proposed to address the challenges presented in the previous section. In the case of VRE curtailment due to transmission congestion, the most straightforward and most common solution is to build new transmission lines or to upgrade the existing ones. For example, Germany has planned to build new transmission lines to transport wind energy from north to south, which is known as the Suedlink project. This project consists on underground transmission lines to reinforce the capacity between northern and southern Germany (TenneT, 2019).

Certain issues can arise when building transmission lines. These include: a) cost, b) required time, c) negative environmental impact, and d) negative social impact. Therefore, building or upgrading transmission infrastructure might not be the optimal solution in some cases.

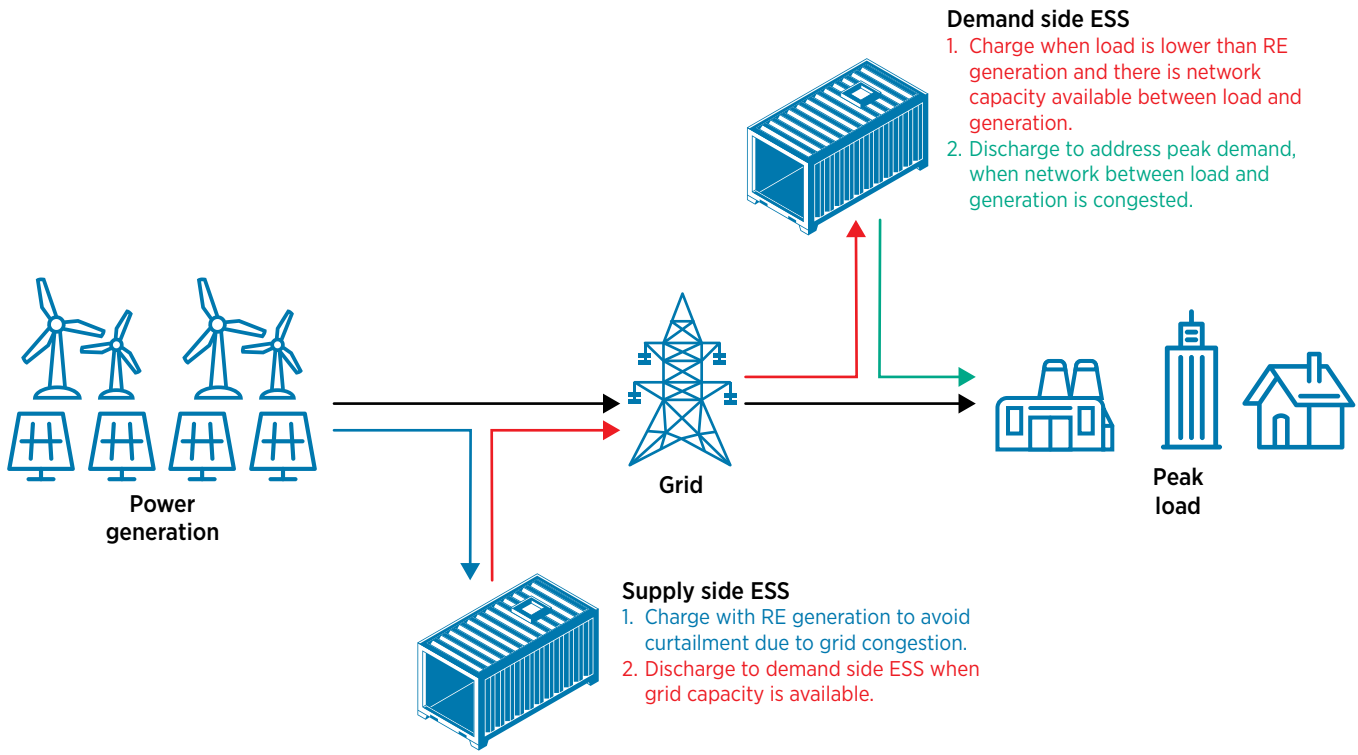
Another option to reduce transmission congestion is dynamic line rating, which consists of better monitoring the thermal conditions of the line to vary the transmission limit. For example, Terna, the Italian system operator, has been applying dynamic line rating in some power lines by better monitoring their thermal parameters, proving that power lines can go beyond their limit in certain specific periods during which VRE penetration is high (Carlini, Massaro and Quaciari, 2013). More information on dynamic line rating can be found also in IRENA (forthcoming-a).

In the case of distribution, one of the solutions that has been already implemented is advanced inverters for distributed solar PV, which allow more efficient voltage regulation and therefore a higher hosting capacity on the feeder (Palminter et al., 2016).

A solution that could address some of the challenges that VRE introduces to T&D systems is energy storage, given its expected drop in costs by 2030 (IRENA, 2017a), its rapid construction time, and its lower social and environmental impacts compared with transmission or distribution lines. Energy storage can be at the transmission level (utility-scale energy storage) or at the distribution level, and can constitute what has been referred to as "virtual power lines". The main idea of this is to place energy storage systems close to where congestion is observed within the network, and let them absorb the excess VRE generation for dispatch later when the line is not congested.

Additionally, energy storage can provide reactive power control and voltage regulation, and can increase the hosting capacity of the distribution feeders, avoiding investment in distribution equipment. In short, energy storage could be a highly suitable solution to minimise the impact of VRE on T&D infrastructure. Figure 52 illustrates how energy storage could provide this service at a transmission level.

Figure 52: Energy storage for transmission deferral



Note: ESS = energy storage system.
Source: IRENA (forthcoming-b).

3. Storage projects for T&D investment deferral

This section presents some storage projects that have been installed or that have been planned with T&D investment deferral as their main goal.

In 2015, Terna installed 38.4 MW/250 MWh of sodium sulphur (NaS) batteries in the Campania region of Italy to provide transmission upgrade deferral (Figure 53). At that time Italy had an excess of wind generation and its transmission capacity was not enough to transport all this energy to the north, with Terna being forced to curtail the excess wind energy. With the installation of the battery system, the excess wind energy could be absorbed and later used during periods with low wind generation, avoiding the need to invest in new transmission capacity. Additionally, this battery can provide other services such as primary and secondary reserves, load balancing and voltage control (NGK, 2019).

In Germany, TenneT (one of the country's system operators) together with the battery manufacturer Sonnen and IBM launched in 2017 a pilot project in which they used blockchain and home battery systems to absorb part of the excess wind energy in the north of the country arising due to transmission congestion. Sonnen acts as a storage aggregator using its sonnenCommunity while IBM provides the blockchain technology. The result is what has been called a "virtual power line" that brings benefits not only to customers, but to everyone using the grid (Hörchens and Bloch, 2017).

In California, one of the utilities joined with Greensmith to install a 2 MW/6 MWh battery storage system to avoid distribution investment in San Juan Capistrano (Figure 54). The project started with 1 MW/3 MWh and then doubled in size. This battery system offsets the peak demand overload and avoids distribution upgrades. Additionally, this battery can also participate in other ancillary services thanks to its control system (Greensmith Energy, 2016).

Figure 53: NaS batteries from NGK in Varel (Germany), similar to the ones in Campania region

Source: NGK

Figure 54: Greensmith battery storage system for distribution deferral in California

Source: Wärtsila

In Maine, GridSolar together with Central Maine Power (CMP) and other parties commissioned a 500 kW, 6-hour grid-connected storage facility (lead acid batteries) to help resolve a sub-transmission constraint in Boothbay (Maine). Initially, CMP had proposed to invest USD 1.5 billion in transmission upgrades; however, GridSolar intervened arguing that CMP's load forecasts were too high and the number of hours for which the upgrade would be needed were very limited. With the installation of storage and other distributed energy resources (e.g. demand response or solar PV), the project yielded USD 12 million of savings in present value terms with respect to the transmission alternative. This project started in Q4 2013 and ended in Q1 2018 because electric load growth did not materialise and the resources were no longer needed (Chew et al., 2018).

In Arizona, the Arizona Public Service (APS) has installed two 1 MW/4 MWh (thus, total of 2 MW/8MWh) battery modules to avoid investment in 20 miles of distribution lines in the remote community of Punkin Center. The project was proposed due to load growth in Punkin Center that could result in a thermal overload of the feeder. APS considered not only batteries but also diesel gensets, combined solar and storage and traditional line upgrades. Of all these alternatives, the battery option provided the least-cost best-fit solution. The project became commercially operational in March 2018 and successfully provided feeder peak shaving during summer 2018, the utility considering the energy storage solution to be a cheaper option (APS, 2019; Chew et al., 2018).

Finally, the French transmission system operator RTE is considering commissioning a "virtual power line" in 2020 under the RINGO project. RTE would place three 12 MW/24 MWh battery systems in three different sites on the network where the lines are congested, to absorb excess VRE generation. In principle the batteries would be operated by RTE only as virtual power lines for the first three years, after which they will also provide other services (Energy Storage World Forum, 2018).

As seen, many storage projects have already been commissioned to avoid T&D investment or upgrades. According to a study performed by Navigant Research, these projects amounted a total of 331.7 MW worldwide in 2017. Furthermore, some 14 324 MW of energy storage systems are expected to be installed by 2026 for the deferral of T&D investment (Navigant Research, 2017).

4. Conclusions (Case 5: T&D investment deferral)

One of the main impacts of VRE penetration is an increase in T&D congestion. Power systems need to be planned well in advance to avoid congestion situations that might cause VRE excess being curtailed. Building new capacity is currently the most straightforward and most common option, even though it is costly, damaging to the environment and sometimes fails to gain social acceptance. Other possible solutions are therefore also worth considering to avoid network investment.

Energy storage could be a solution to avoid congestion and defer investment in the T&D network. Some projects have already been installed and successfully tested. For example, in Italy Terna installed 38.4 MW/240 MWh of sodium sulphur batteries for transmission investment deferral. In the United States several projects have been installed to avoid distribution upgrades (e.g. the Boothbay project in Maine). According to Navigant Research, around 331.7 MW of storage was commissioned to avoid T&D distribution congestion, and this number is expected to reach 14 324 MW by 2026.

Energy storage could make investment in T&D systems unnecessary in some cases; however, depending on system needs, situations may still arise where building new transmission or distribution lines is required (e.g. transmission in Germany).

5. Further reading

Virtual power lines are among the innovations considered in IRENA's Innovation Landscape study. For more, see:

IRENA (forthcoming), "Innovation Landscape Brief: Virtual power lines", International Renewable Energy Agency, Abu Dhabi.


Photograph: Shutterstock

Case 6: Peaking plant capital savings

1. Challenge – Ensure generation adequacy

To operate the power system in a secure and reliable way, generation must equal demand at all times. To achieve this, the system operator must schedule and operate power plants to meet that demand in the short term. Additionally, it has to ensure enough generation capacity in the medium and long term to cover the forecast peak in demand plus the required capacity margin.[38] In traditional power systems, where VRE penetration was low, procuring adequate capacity to meet future demand was a straightforward process, as these systems were usually based on hydrothermal generation capacity. Thermal generation units typically have a clearly defined firm capacity,[39] which can be calculated based on the forced outage rate, which is the probability of the unit having an unexpected outage. For hydro generation, estimating the firm capacity has a higher degree of complexity given its limited energy (water in the reservoirs is not infinite). In this case, however, each power system has acquired its own well-defined methodology to calculate the equivalent firm capacity of hydro generation and therefore poses no problem. For this reason, if the VRE penetration is low, the system operator can easily determine whether the installed capacity on the system is enough to ensure a defined level of reliability.

The problem, however, arises when VRE penetration increases. VRE is variable, meaning its output is only partially predictable. This makes the firm capacity of these resources more difficult to estimate. At high levels of VRE penetration, ensuring the system's reliability can therefore be a challenge for system operators. Different methodologies have been proposed in the literature to estimate the firm capacity of VRE resources. One of the best-known is the expected load carrying capability (ELCC), as first proposed by Garver (1966). In short, this methodology is based on how much demand can be increased with the addition of the VRE resource to obtain the level of reliability the system had without the VRE resource. The methodology has been widely accepted in the literature; however, its implementation is not that simple, requiring an iterative process and the use of optimisation techniques, as well as historical data on VRE generation.

Therefore, with the introduction of VRE – given its variability and uncertainty – it becomes challenging to calculate the capacity requirements of the system to ensure reasonable levels of reliability. An incorrect evaluation of capacity needs could result in false economic signals, ultimately leading to an increase in unnecessary peaking plant investments, causing overcapacity. At present, although many other factors have been influential, several power systems have overcapacity (e.g. Spain, Italy and Germany). This overcapacity results in the continuous shutdown of power plants, which are not therefore able to recover their initial investment costs. Additionally, overcapacity can ultimately be a barrier to further VRE deployment, since the system will not require these resources from a security of supply perspective (del Río and Janeiro, 2016)

To sum up, generation adequacy must be better planned to avoid investment in unnecessary and expensive peaking plants and avoid overcapacity.

2. Solution: Capacity mechanisms vs scarcity price

Several solutions have been proposed to ensure generation adequacy in a market context. They can essentially be classified into two, as proposed by Batlle and Rodilla (2013): a) energy-only markets, in which the regulator does not intervene; and b) security of supply mechanisms, in which the regulator intervenes.

Energy-only markets

The energy-only market solution affirms that market price signals are enough to ensure generation adequacy. This solution lies under the assumption that electricity markets are perfectly competitive, and prices will reflect when new generation capacity is required in the system. Low prices usually mean the system has enough generation capacity, so that bringing new generation into the market would not be profitable. However, as demand grows and capacity is decommissioned, prices increase and can reach what is referred to as the "scarcity price".[40] At this point, price signals are high enough for new generation capacity to enter the market and recover its investment costs.

However, the reality is that markets are not perfect and waiting for the scarcity price is not always a valid solution. Additionally, power systems that rely on scarcity pricing usually allow some kind of intervention by the regulator because, among other reasons, the regulator is not going to risk system reliability by waiting for the scarcity price to appear.

Real examples of energy-only markets are ERCOT (Texas, United States), NEM (Australia) and AESO (Alberta, Canada), although the latter planned to implement a security of supply mechanism in 2019.

38 The capacity margin is usually expressed as a percentage of the peak load and represents how much capacity in addition to the peak load is required in the system.

39 Firm capacity is the amount of energy available for production or transmission that can be (and in many cases must be) guaranteed to be available at a given time.

40 The scarcity price is an extraordinarily high price that is reflected both in the operating reserve market and the wholesale market, confirming scarcity conditions in the system. Typically, to reflect scarcity the operating reserve price rises and then the energy price rises to reflect the opportunity cost of reserve capacity. The scarcity price should provide incentives for new generation to enter at the right time where capacity would be needed (Hogan, 2013).

Security of supply mechanisms

Security of supply mechanisms imply that the regulator intervenes to ensure generation adequacy. These mechanisms can be classified as price mechanisms, which are also known as capacity payments, and quantity mechanisms:

- **Price mechanisms** set an income that generation will receive for providing firm capacity, but they do not specify the quantity required, so the regulator cannot set a target for how much capacity the system needs. The procured capacity can be higher or lower than the amount required.

- With **quantity mechanisms** the regulator stablishes the capacity required to ensure generation adequacy and lets the market set the right price. These mechanisms can be divided into three categories: capacity markets (e.g. Guatemala and Western Australia), long-term auctions for delayed-delivery reliability products (e.g. Brazil, ISO New England and PJM), or strategic reserves as a reliability product (e.g. New Zealand).

Of the two options – energy-only markets or security of supply mechanisms – the latter seem better at incentivising energy storage systems. Additionally, an energy storage resource might not make enough revenue in an energy-only market given a) the limited energy capacity of these resources, and b) batteries suffer from degradation when they charge and discharge, and seeking revenue in markets that pay for being available might be more profitable.

This particular case, therefore, assumes that the regulator needs to intervene to ensure generation adequacy.[41] Thus, the focus will be on innovations in security of supply mechanisms. Further research is needed to see how these mechanisms could incentivise the installation of energy storage and enable a reduction in peaking plant capacity.

3. Energy storage deployment with security of supply mechanisms

As explained above, regulators have been using security of supply mechanisms to procure sufficient capacity and maintain a certain level of reliability; however, these mechanisms have usually included only thermal and hydropower plants. With the introduction of VRE into the system and new technologies such as energy storage systems, these mechanisms should be redesigned to allow the participation of new technologies that could contribute to system reliability more efficiently and avoid investment in unnecessary peaking plants. If they are well redesigned, energy storage may be able to obviate the need for investment in peaking power plants that would otherwise be needed to ensure system reliability.

For example, in the United Kingdom the implemented security of supply mechanism allows the participation of storage projects. The mechanism, proposed in 2013 as part of electricity market reform, is a long-term auction for a delayed-delivery reliability product. The mechanism has two types of auctions: T-4, which is held four years in advance (capacity is not required until four years later), and T 1, which is held one year in advance. There has been some criticism of this market as it has awarded contracts to active nuclear and coal-fired power plants, although their participation has been reduced every year. According to KPMG (2018), contracts for storage projects have already been awarded in the capacity market (see Figure 55).

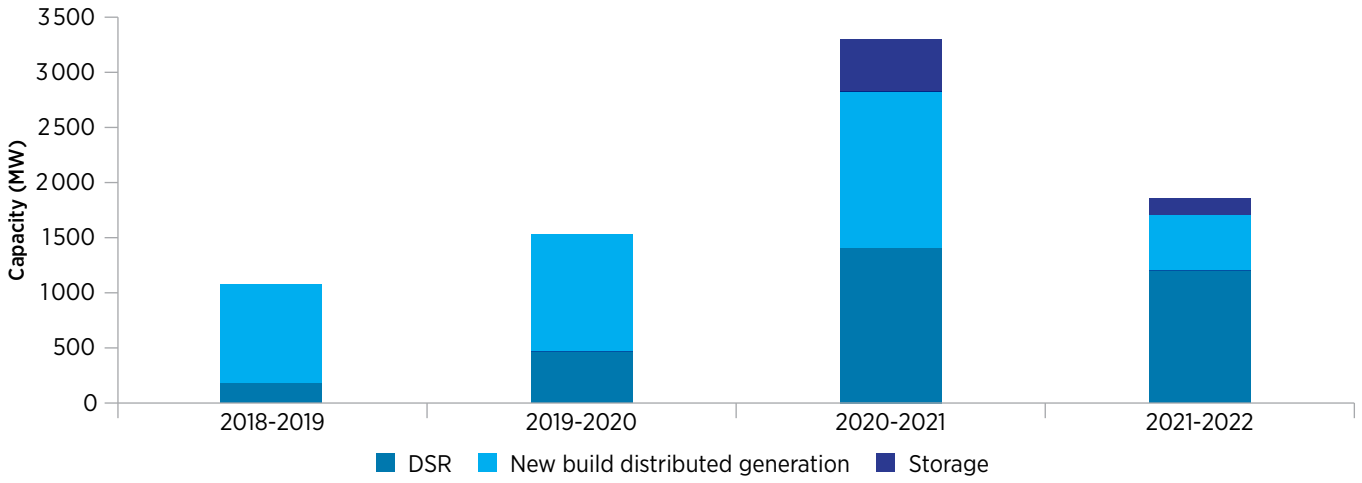
The reason why storage capacity success declined in 2021–22 is because in 2017 the UK government introduced a de-rating factor[42] for storage based on the duration of discharge. The de-rating factor reflected the contribution of different types of energy storage to security of supply. It favoured long-duration energy storage (> 4 hours) with a 96.11% factor over short-term storage (e.g. de-rating for 1-hour storage is 36.11%) (Everoze, 2017). This, combined with the predominance of short-term storage in the United Kingdom because of the enhanced frequency response auction, led to contracts awarded to storage falling to 150 MW in the most recent T-4 auction from 500 MW in the previous one. Last but not least, at the end of 2018 the UK capacity market was declared illegal by a European Union court ruling and is currently not in operation (Cuff, 2018). However, both parties are currently working to bring it back.

Storage technologies can improve system reliability, reducing the need for peaking plants

41 Discussion continues on whether this intervention is needed or an energy-only market should be sufficient.

42 The de-rating factor amends payments to storage projects to reflect their contribution to security of supply.

Figure 55: Decentralised capacity successful in capacity market auctions, United Kingdom, 2018–22



Note: DSR = demand-side response.
Source: KPMG (2018).

Other examples of capacity markets in which storage could potentially participate are as follows:

- **United States.** A recent order from the Federal Energy Regulatory Commission (FERC) allows energy storage to participate in capacity markets. This order mandates independent system operators to revise tariffs and establish rules that recognise the physical and operational characteristics of energy storage systems (Walton, 2018).

- **Alberta (Canada).** In January 2017 the Government of Alberta decided to design and implement a capacity market in Alberta in collaboration with the Alberta Electric System Operator (AESO). Storage will be able to participate in this capacity market, albeit with the following conditions: a) the minimum size of the assets must be 1 MW, and b) the storage assets must demonstrate an ability to continuously discharge for 4 hours. Additionally, all participating generating and storage assets must submit their ramping capability, which means that the capacity market includes some flexibility requirements. No auction has yet been launched in Alberta, but one was planned in 2019 with first delivery of capacity expected in 2021 (AESO, 2018).

- **Italy.** This capacity mechanism is also a quantity-based mechanism based on reliability option contracts (see Batlle and Rodilla, 2013) and was approved by the European Commission in February 2018. As in the Alberta case, no auctions have been launched yet. More information can be found in Mastropietro et al. (2018) where the authors provide a critical review of the Italian capacity mechanism.

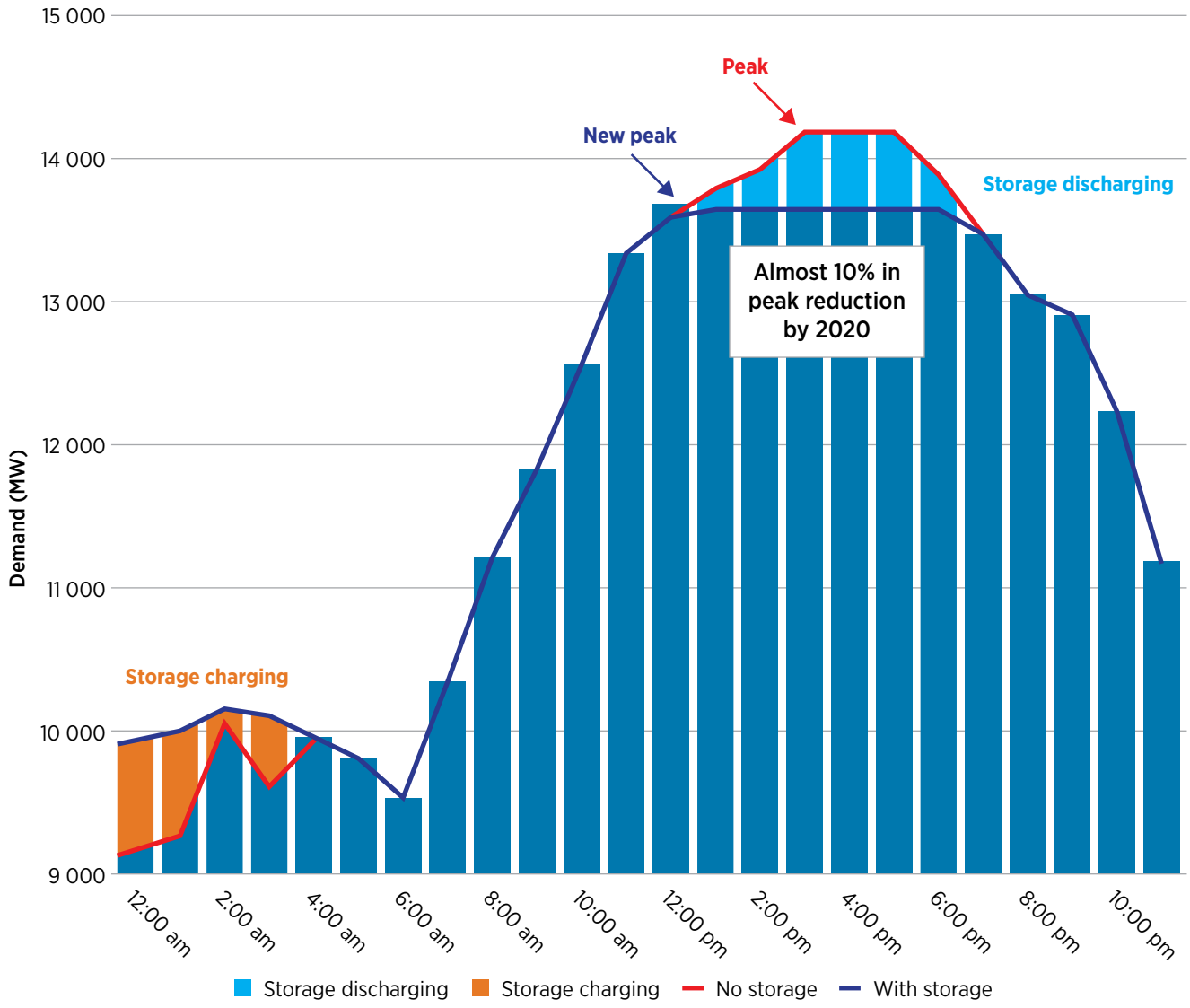
4. Storage enables savings in peaking plant investment

The previous section demonstrates how security of supply mechanisms can yield the deployment of energy storage systems to provide firm capacity. The United Kingdom has already installed storage via capacity mechanisms, while other systems such as those in Italy and Alberta have a mechanism in place, but are yet to launch an auction. This section explains the effect of installing storage to provide firm capacity, which is mainly a reduction in peaking plant investment and associated capital costs.

The peaking plant capital savings have been widely researched, for instance in the Massachusetts "State of charge" report (Customized Energy Solutions et al., 2016), where they estimate that 1 766 MW of energy storage would yield USD 2.3 billion of benefits, of which USD 1 093 million would be related to reducing peak capacity. This would defer the capital costs of peaking plants and reduce costs in the capacity market. The authors also show how the demand curve would look with and without storage (Figure 56).

A further example can be found in a report by Strategen (2017), which researches the feasibility of energy storage replacing peaking power plants in New York City. Here they identify energy storage as a very good candidate to replace old peaking plant instead of installing new natural gas generation, given its capability to maintain system reliability and reduce pollutant emissions. They provide an economic evaluation of energy storage and conclude that it is increasingly cost-competitive with new natural gas peakers in New York City and could be a viable option for the region. Additionally, they mention that some system-level benefits of storage are currently not being compensated under the New York Independent System Operator (NYISO) market design. If these benefits were monetisable, that is, if energy storage could earn revenues for them, then installing more storage would be cost-effective and could help avoid investment in additional peaking plants.

Figure 56: Demand curve with and without energy storage, Massachusetts, 2020

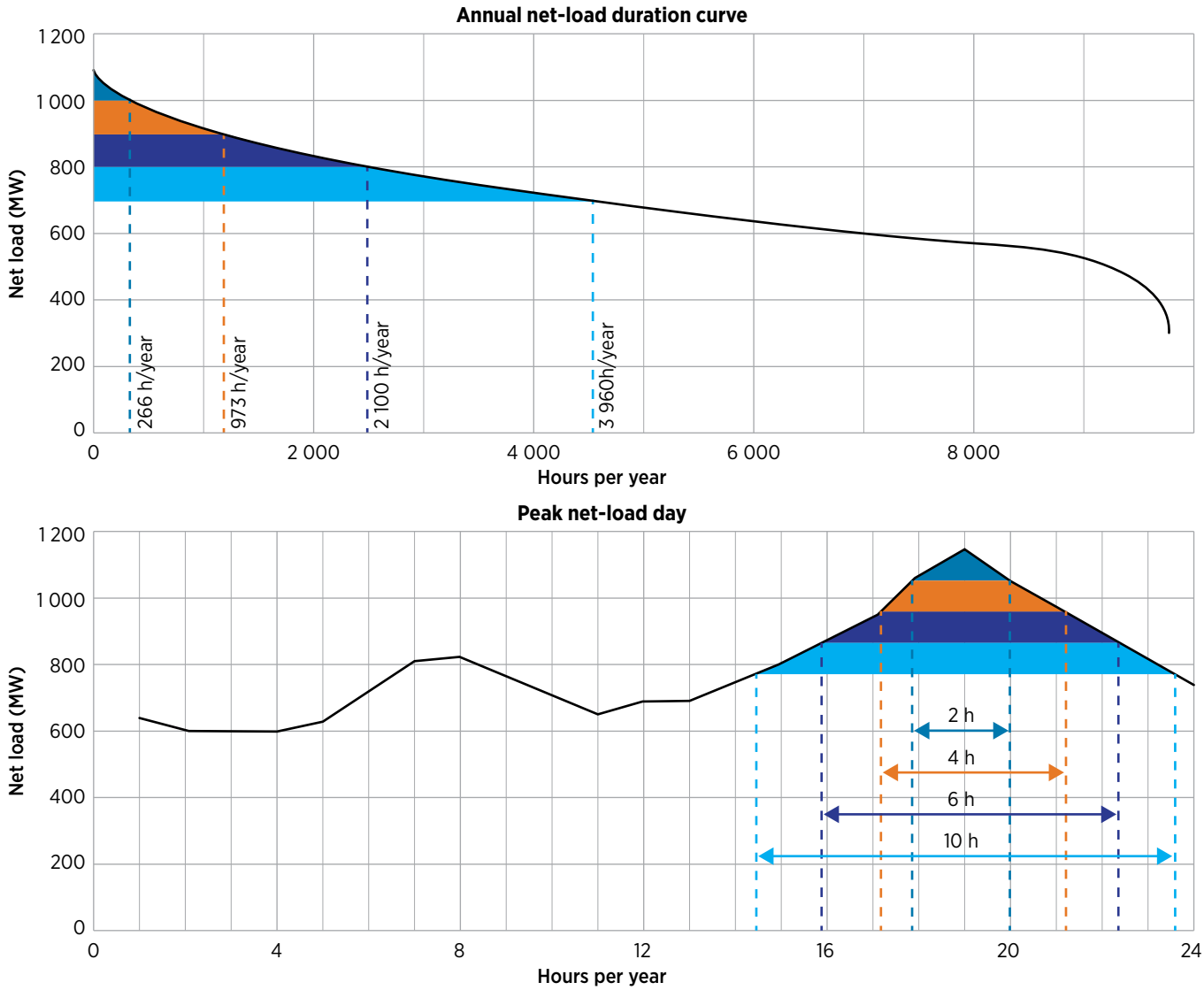


Source: Customized Energy Solutions et al. (2016).

Electricity storage can effectively replace peaking plants is when it is coupled with solar PV resources. Solar and storage constitute a firm capacity resource that could increase savings from reduced peaking plant investment. A current example is the 409 MW/900 MWh battery that Florida Power and Light is to install by 2021 to replace two natural gas plants. The plant, known as the FPL Manatee Energy Storage Center, is expected to constitute the largest battery installation in the world. The plant will charge from an existing solar plant located in Manatee County. The battery is expected to save USD 100 million for customers through avoided fuel costs and should also help to avoid 1 million tonnes of CO2 emissions (Geuss, 2019). This is a relevant case study to demonstrate how storage can avert the need for peaking plant capital investment when coupled with solar PV. In this case storage can maximise the firm capacity of solar PV and turn it into a dispatchable energy source capable of participating more easily in security of supply mechanisms. This maximises revenues in a system with predominant solar resources. Solar PV and storage must therefore be studied as a single resource given the synergies that exist between them (Denholm and Margolis, 2018).

A consideration to be taken into account in this case study is the saturation effect of peak load reduction, as explained in Stenclik et al. (2018). This effect means that the duration of storage is relevant in this application. In the United States, for instance, a battery storage system is treated as a firm capacity resource if it has a minimum four-hour duration, when it is therefore considered as a conventional thermal resource. This assumption is fine if a small amount of storage is installed to cover certain high-risk peak hours in the year. However, when storage penetration increases, the efficacy of four-hour storage in replacing peaking plants is reduced and the duration of storage must be increase (Figure 57)

Figure 57: Saturation effects of peak load reduction



Source: Stenclik et al. (2018).

5. Conclusions (Case 6: Peaking plant capital savings)

System operators have to ensure that the power system has enough firm capacity to cover peak demand at all times. With a high penetration of VRE, whose firm capacity is not straightforward, ensuring generation adequacy can be challenging and might result in overcapacity in the system. Power systems must ensure that the right price signals are always in place (via the scarcity price) or implement security of supply mechanisms to procure enough capacity and cover the demand peak.

Security of supply mechanisms might be a better option for energy storage since, among other considerations, they offer an additional revenue stream for storage. An example of storage deployed via security supply mechanisms is the UK capacity market, while other systems are also implementing capacity mechanisms where storage can participate (e.g. United States, Alberta and Italy).

Energy storage can then be used to cover the peak demand and avoid the need for investment in peaking plants. This has been proven in studies carried out on projects in Massachusetts and New York City, and another project in Florida will see the installation of the largest battery storage system in the world.

6. Further reading

Electricity storage is one of the main solutions for a renewable-powered future considered in the IRENA Innovation Landscape Report, and the redesign of capacity markets is one of the 30 innovations considered. For more information read:

IRENA (2019), "Innovation Landscape for a renewable-powered future: Solutions to integrate variable renewables", International Renewable Energy Agency, Abu Dhabi.

IRENA (2019), "Innovation Landscape Brief: Redesigning capacity markets", International Renewable Energy Agency, Abu Dhabi.

Case 7: Enabling high shares of VRE in the off-grid context

1. Challenges

Sustainable Development Goal 7 is aimed at ensuring access to affordable, reliable, sustainable and modern energy for all by 2030. With almost 1 billion of the world's population still not having access to electricity, most of whom live in rural areas, off-grid renewable energy systems represent a key solution to achieving SDG7. In particular, solar PV is highly scalable and easy to deploy anywhere, including in the most remote locations.

Where electricity is accessible, a major challenge for people living in rural areas is the reliability of supply. Many people with unreliable electricity supply suffer from constant power outages and greatly rely on expensive and polluting diesel generators as backup to the grid, even for everyday needs such as lighting.

With the rapid decline in the cost of renewable power generation technologies in recent years, the electricity sector has made substantial progress on decarbonisation. However, renewables deployment needs to be accelerated to ensure access for all by 2030. To ensure reliable 24/7 access to electricity, solar PV combined with battery storage has become the key solution in off-grid contexts and for unreliable grids, driven by technology improvements and cost reductions.

2. Solutions

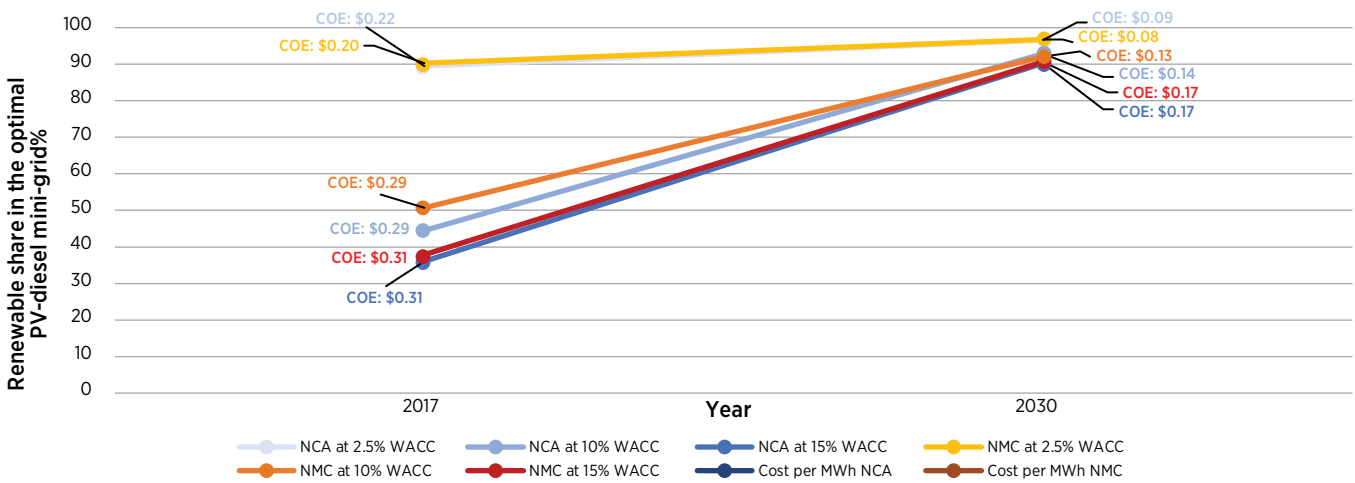
Deploying solar PV with batteries allows not only for energy to be stored and used during times when the sun is not shining, but also greater flexibility as solar PV grows to become the main source of electricity supply in off-grid and weak grid locations. This combination of technologies can be deployed at any scale and almost anywhere in the world.

In common with solar PV and wind technologies, battery storage has shown rapid declines in cost in recent years, and these are expected to continue in the future (IRENA, 2017a). With such competitive costs, and lower to come, the share of solar PV in hybrid mini-grids is expected to increase; increasing battery storage capacity can help increase the share of electricity from solar PV in mini-grids, reducing the use of diesel generators to a few percentage points.

Figure 58 shows the solar PV share in a least-cost mini-grid in 2017 and in 2030, considering two types of Li-ion batteries (nickel manganese cobalt [NMC] and nickel cobalt aluminium [NCA]). The graph has been prepared using results from energy modelling software (HOMER Pro) and input data from IRENA's latest cost report on storage (IRENA, 2017a). It shows that, in 2017, development projects with a 2.5% nominal discount rate had an optimal solar PV share of about 90% with either NCA or NMC batteries. Commercial projects in a low-risk context (10% weighted average cost of capital [WACC]) had renewable share values of 44.5% with NCA and 50.7% with NMC. The results for the optimal PV share in mini-grids in a riskier context (15% WACC), typical of off-grid locations, showed a renewable fraction of only 36% using NCA and 38% using NMC batteries.

Due to technological advancements and expected cost reductions, capital costs for battery storage are expected to decline by more than 50% by 2030, thus boosting the amount of storage that is economical to deploy in mini-grids, and consequently boosting the amount of solar PV that can be accommodated. Most importantly, the results show that in 2030, no matter the source of finance, the optimal renewable share in mini-grids is expected to be more than 90%, very different from the case today. This means that no matter the WACC at which projects are financed (2.5%, 10% or 15%), all mini-grid projects are expected to have an optimal amount of solar PV of more than 90%, thanks to PV and battery cost reductions.

Figure 58: Solar PV share in least-cost hybrid mini-grids



Note: COE = cost of energy.

3. Storage deployment in an off-grid context

There has been a rapidly increasing interest in deploying storage solutions in off-grid contexts, especially in mini-grids that are located in rural areas where there is no access to the electrical grid or on islands that rely on expensive and polluting diesel generation. This has been driven by the need to accommodate increasing amounts of solar PV, and to a lesser extent wind, to provide electricity access or displace diesel generation.

A real-life example of storage enabling large shares of solar PV to replace diesel in an off-grid context is the island of Ta'u in American Samoa, where Tesla's subsidiary SolarCity has installed a 1.4 MW PV micro-grid along with 6 MWh of Li-ion battery storage from 60 Tesla powerpacks (National Geographic, 2019). This project, which was completed within a year, provides three days of autonomy, hence reducing drastically the usage of diesel generators. American Samoa, together with many islands in the Pacific, Caribbean and Indian oceans, is transitioning from a fossil fuel-based power system to a renewables-based one. Installation of battery storage systems is a key technology enabler for the transition to renewable energy systems.

Due to the rise in operating costs for diesel systems, increased global interest is being shown in hybrid PV-diesel systems. This is especially the case for industrial applications where access to the grid is limited or unreliable. An example of such a system is the 1 megawatt peak (MWp) PV hybrid solution designed, installed and commissioned by Chemtrols Solar Pvt Ltd in June 2013 for the Alpine Knits cotton mill in Palladam, a suburb of Tirupur in Tamil Nadu, India. Previously, the mill had experienced a number of daily power outages, which are common in the state of Tamil Nadu, and hence had opted to use a 1.25 megavolt ampere diesel genset to provide reliable power supply. The mill simply accepted the excessive operational costs and emissions that resulted from the fuel consumption of the gensets. To reduce its high energy bills, the mill opted for a PV-diesel hybrid solution, installing 1 MWp of PV modules on its roof (SMA, 2013).

For the reliable operation of the PV and the genset, Alpine Knits implemented the SMA Solar Technology fuel save controller. The controller, which was mainly developed to integrate high shares of PV into diesel systems, ensures a very efficient power supply and a PV share of up to 60% (as a percentage of the installed diesel capacity). In the event of a sudden drop or major load change in the PV feed-in, sufficient spinning reserves are always present thanks to diesel generation, which is controlled and adjusted automatically.

The implementation of the PV-diesel hybrid system has allowed the cotton mill to operate with a reliable supply of electricity even when the grid fails. Approximately 60% of the total power demand of the mill is provided by solar PV during peak production hours. Apart from a reliable power supply, the mill has benefited from a reduction in operating costs as well as a reduction in CO_2 emissions. In addition to these benefits, Alpine Knits also earns renewable energy certificates (RECs), which could be traded in a price band of INR 9 300 to INR 13 400 per MWh per REC until March 2017. After this date, the Central Electricity Regulatory Commission in New Delhi proposed a price band of INR 1 000 to INR 2 500 per MWh per REC until further notice. According to Chemtrols Solar, the sale of RECs by the cotton mill results in an additional revenue of INR 20 million, or approximately USD 290 000, per annum. The example of the Alpine Knits cotton mill demonstrates how the deployment of a hybrid PV-diesel system can drastically reduce emissions and operating costs, and at the same time provide the operator with a reliable supply of electricity.

However, a hybrid system without the integration of storage can only allow renewable electricity to be generated and used during the daytime. Implementing a battery system not only allows electricity to be stored and used at night, hence resulting in further CO2 and cost reductions, but it also increases the share of renewable energy generated by the system and provides various advantageous services.


Photograph: Shutterstock

In the town of Paluan in the Philippines, Solar Philippines has installed Southeast Asia's largest mini-grid with 2 MW of PV, 2 MWh of Tesla's Li-ion storage powerpacks and 2 MW of diesel gensets as backup (Figure 59) (Kenning, 2018). The mini-grid in Paluan comprises a battery storage system that provides the locals with uninterrupted access to electricity and results in further CO2 and cost reductions. The installation has been designed to provide the town with the required supply of electricity during the day and the storage capacity allows energy to be supplied at night.

Prior to the deployment of the storage plus PV mini-grid, residents in Paluan suffered numerous brownouts and had unstable electricity supply that could last between three and eight hours a day. The mini-grid not only provides clean energy and drastically reduces the diesel consumption of the town, but it also provides the residents with stable and reliable electricity for 24 hours a day. The system shows how a mini-grid can be installed relatively easily using the renewable resources available on the island, thereby providing reliable and clean energy for the community's daily needs. Importantly, the installation was justified and funded without subsidies, proving how competitive and practical installations of solar PV with storage can be in rural areas.

The island of Graciosa, located in the northernmost part of the Azores (Portugal), is a further example of an island community that has implemented VRE with storage, drastically cutting its diesel consumption. Previously relying on 100% diesel to generate electricity for the residents, Graciosa decided to transition to renewable energy generation with a hybrid wind-PV power plant (Figure 60). This new hybrid system comprises a 4.5 MW wind farm, a 1 MWp PV array, a 3.2 MWh Li-ion battery storage system and a transmission line of 5.5 kilometres. The system is designed to achieve a renewable electricity share of approximately 65%. In December 2018, the hybrid mini-grid provided 100% renewable energy to the island for days during the final commissioning tests (Graciólica Lda, 2018; CRL, 2018).

The deployment of 3.2 MWh of storage has allowed a drastic reduction in the consumption of diesel fuel for generating electricity and Graciosa to operate the grid with very high shares of renewable energy.

Figure 59: Inspection of a solar mini grid in Mog Mog, Ulithi atoll, Yap State, FSM

Source: IRENA/E.Taibi

Figure 60: 60 kW solar mini-grid in Ulithi high-school, Yap State, FSM

Source: IRENA/E.Taibi

4. Conclusions (Case 7: Enabling high shares of VRE in the off-grid context)

Many rural areas and islands are still heavily dependent on fossil fuels such as diesel for electricity generation. In many such locations, the supply of electricity is not reliable and many people only have access to electricity for certain hours of the day, while those with the economic means resort to diesel generation for backup power. At current costs for solar PV and battery storage systems (and with further cost reductions expected), the use of renewables is a viable alternative to fossil fuels for electricity generation in rural areas and islands and has become the least-cost solution, in addition to being the most environmentally sound.

To deploy mini-grids on islands or in rural off-grid areas, battery storage systems are key to balancing the variability of resources such as wind and solar PV and to shifting the electricity generated at times of excess supply to times where demand would otherwise exceed supply. This is the key value proposition for storage in such applications: enabling very high shares of VRE to be reached in mini-grids by eliminating the need for any synchronous generation and decoupling electricity demand from VRE supply.

Further benefits of implementing battery storage systems in an off-grid context include: reduced environmental impact (local emissions, global emissions, fuel leakages), reduced dependency on price-volatile imported fuels, and increased energy independence. In addition, battery systems with grid-forming inverters can provide all the necessary services to the grid, including black start capability, frequency and voltage control, and reserves to cater for the uncertainty of solar PV and wind forecast errors. The emergence of grid-forming inverter technologies, often linked to battery systems, enables the power system to completely switch off any form of conventional, so-called synchronous, generation and provide all the necessary services to the power system. While this is still a matter of research in large continental grids (e.g. MIGRATE 2020 project),[43] at mini-grid level (from a few watts to tens of megawatts) this is proven technology, with over a decade-long track record of reliable operations in some of the most remote and environmentally demanding conditions.

The case studies discussed in this chapter further highlight how implementing more storage capacity in mini-grids can help drastically reduce fossil fuel consumption and increase the share of VRE. This aids the transition from 100% diesel to 100% renewable electricity generation in off-grid areas, with off-the-shelf technologies already available and at competitive cost.

43 www.h2020-migrate.eu.

5. Further reading

Renewable mini-grids are one of the 30 innovations considered in the IRENA Innovation Landscape Report. For more information read:

IRENA (2019), "Innovation Landscape Brief: Renewable mini-grids", International Renewable Energy Agency, Abu Dhabi.

Case 8: Behind-the-meter electricity storage

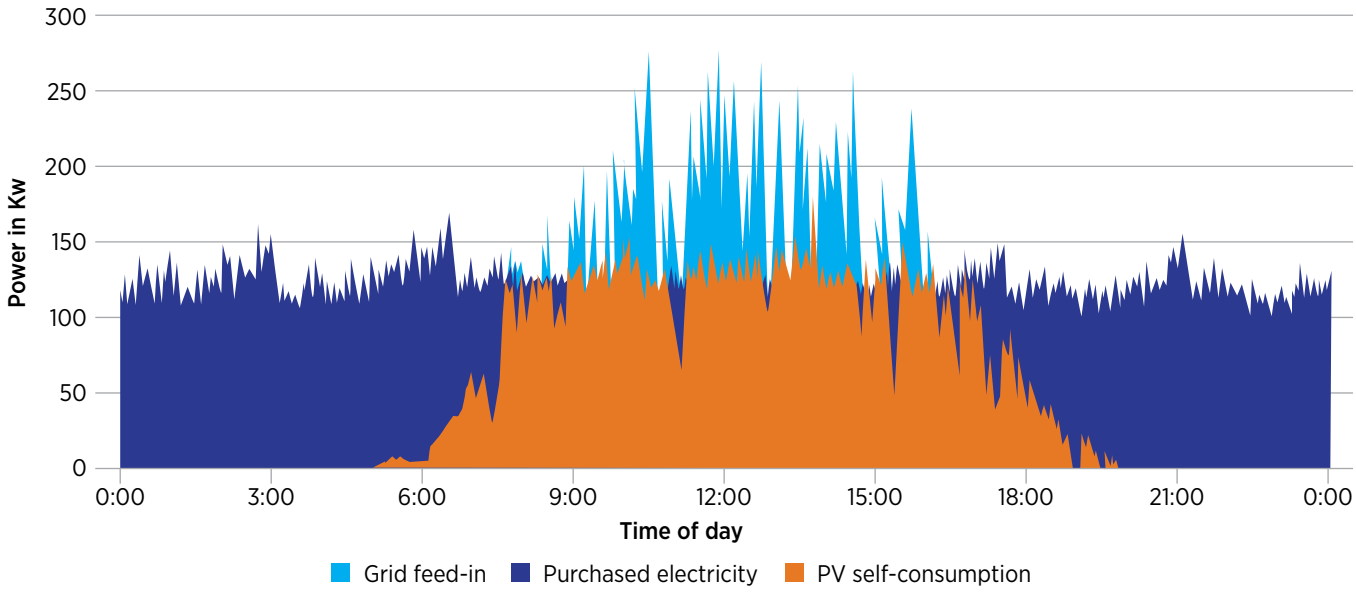
1. Challenges for self-consumption of VRE

Power systems worldwide are undergoing a deep transformation. Systems that traditionally had a centralised structure with large thermal and hydro generating units are shifting towards a more complex and decentralised system. The increasing penetration of renewable energy, the expansion of markets and the deployment of information and communications technologies (ICT) in the power sector are enabling the shift of generation towards smaller units connected to the distribution system and forming what is referred to as the smart grid. In this new grid paradigm, self-consumption of renewable energy at consumer level is one of the main innovations that can change drastically how the power system is structured and operated.

Self-consumption of renewable energy can be defined as electricity generated from renewable energy sources not injected into the distribution or transmission grid or instantaneously withdrawn from the grid, but instead consumed by the owner of the power production unit or by associates directly contracted to the producer (Dehler et al., 2017). Given the steep reduction in the cost of renewable energy (IRENA, 2018c), some consumers are finding it economically and technically feasible to install their own generation, and self-consumption is therefore starting to become a widespread concept. From the different renewable energy sources, solar PV is the most common for self-consumption given its low costs and modularity, among other features. Small wind turbines, although not widespread yet, have also been designed to be used for self-consumption (Enair, 2019).

The main challenge for self-consumption of renewable energy is that solar PV and wind are variable resources and their production does not follow the consumer's demand. Thus, in some periods there will be an excess of energy while in others demand will not be met. For this reason, customers cannot solely rely on VRE to cover their demand. The most common solution to this has been to install, for instance, a solar PV panel to cover demand during the day, and at the same time have a connection to the electricity grid to draw electricity in case of shortages or to feed the grid with excess solar PV generation that would otherwise be curtailed. This is shown in Figure 61.

Figure 61: Demand and generation in a self-consumption system



Source: SMA Solar Technology (2019).

Under this scenario consumers are not totally independent and still rely on the electricity grid to cover their demand. If the objective is to gain independence from the electricity grid (off-grid system) or to maximise the economic benefit of the electricity fed into the grid, other solutions must be found. In this regard, electricity storage (e.g. a battery) could provide significant value to the owner of the decentralised renewable energy generation system (e.g. a rooftop PV), as well as to the electricity grid.

2. Solution: Behind-the-meter electricity storage

Electricity storage is capable of absorbing excess energy that cannot be used at a particular moment and making it available for use at a later stage when required. From a self-consumption perspective, electricity storage can be coupled with rooftop solar PV so that the excess of electricity during the day can be absorbed and used during the night, when the sun is not shining. This type of electricity storage is usually referred to as behind-the-meter (BTM) storage because it is located downstream of the connection point between the utility and the customer.

Benefits for the consumer

The main benefit of BTM storage is to maximise self-consumption of renewable energy. This means that the storage system absorbs any excess energy and uses it to cover demand when solar PV production is not available. In this case, if the storage system cannot cover demand, electricity can be still drawn from the grid. Other benefits of BTM storage according to IRENA (2019d) are also:

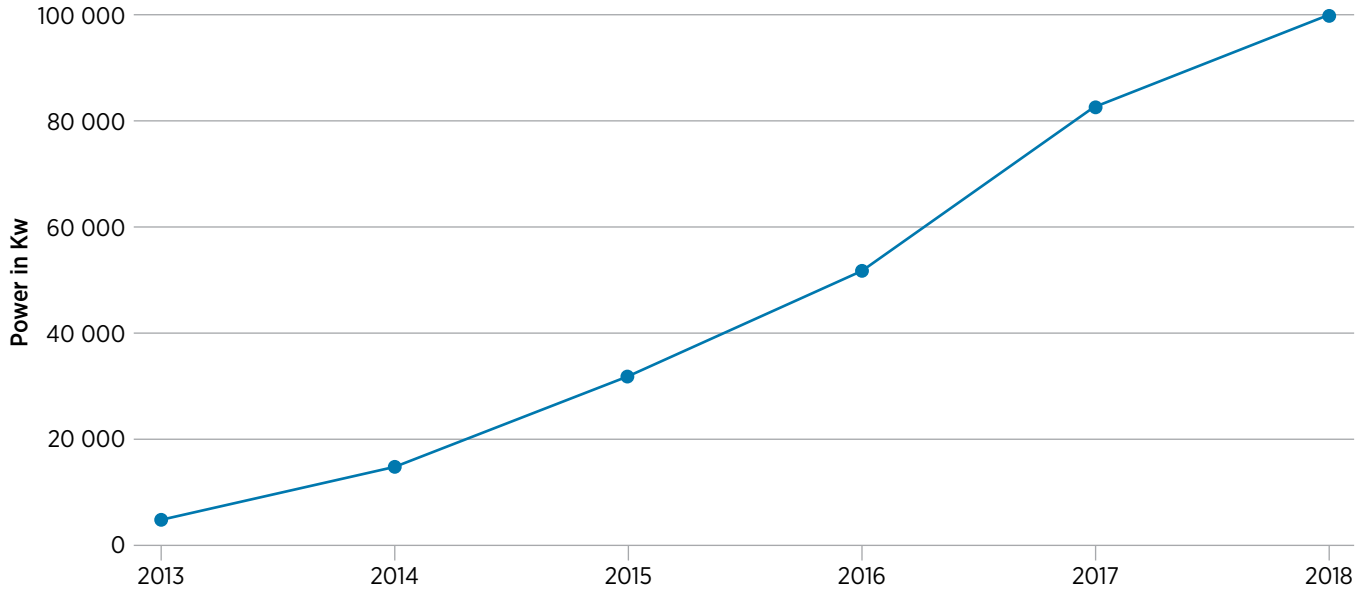
- Reducing the consumer's electricity bill by absorbing electricity when there is an excess of VRE generation or when electricity prices are low, and selling the absorbed energy to the electricity grid during periods when prices are high.
- Reducing demand charges, which are usually based on the consumer's highest electricity usage requirement .
- Providing backup power and increasing energy resiliency for the consumer.

Benefits for the system operator

If the consumer is connected to the electricity grid, BTM battery storage could also have benefits for the system operator. IRENA (2019d) shows that the main benefits of BTM storage for system operators are:

- Providing flexibility through frequency regulation and energy shifting (see the cases "Operating reserves" and "Energy arbitrage").
- Deferring network investment (see the case "T&D investment deferral").
- Deferring peaking plant investment (see the case "Peaking plant capital savings").

Figure 62: Household battery storage systems in Germany, 2013–18



Source: Rathi, A (2018).

3. BTM battery storage deployment and real examples

The installation of BTM storage has been a popular option in many countries worldwide and continues to grow year on year. For example, in Germany the number of residential battery systems installed exceeded 100 000 by summer 2018 (Figure 62) and this number is expected to double by 2020 (Parkin, 2018).

Another example of increasing installation of BTM storage can be found in Australia where in 2017 21 000 household battery systems were in place. Australia is expecting this number to grow in the coming years, with the goal of achieving one million installed household battery systems by 2025. For the moment, the federal government is planning to commit AUD 200 million to incentivise the installation of 100 000 new household battery systems. The proposed programme would grant consumers AUD 500/kWh if they decide to install a battery system up to 4 kWh, hence a maximum grant of AUD 2 000 per system is possible (Martin, 2018).

BTM battery storage projects that have been providing benefits to both the consumer and system operators are presented in more detail in IRENA (2019d), including:

- Poway Unified School District's 6 MWh BTM battery storage system. This school district in California expects savings of around USD 1.4 million over 10 years, with the main application being lower charges for power consumption (Engie Storage, 2018).

- Green Mountain Power has installed 2 000 Tesla Powerwall 2 units in its customers' premises in Vermont, United States, to provide backup power and support the grid. These systems cost consumers USD 1 500 upfront or USD 15 per month, and the utility expects consumers to benefit from savings of USD 2–3 million over the programme lifetime. As for the grid benefits, the installed batteries helped to cover Vermont's peak demand in July 2018 via peak shaving and saved the utility USD 500 000 (Brooks, 2018).

- Eneco, a utility in the Netherlands, started CrowdNett, which is a virtual power plant of BTM battery storage systems. Apart from increasing self-consumption and yielding bill savings for consumers, these batteries can participate both in the spot and ancillary services markets, yielding benefits to the grid as well (Eneco, 2016).

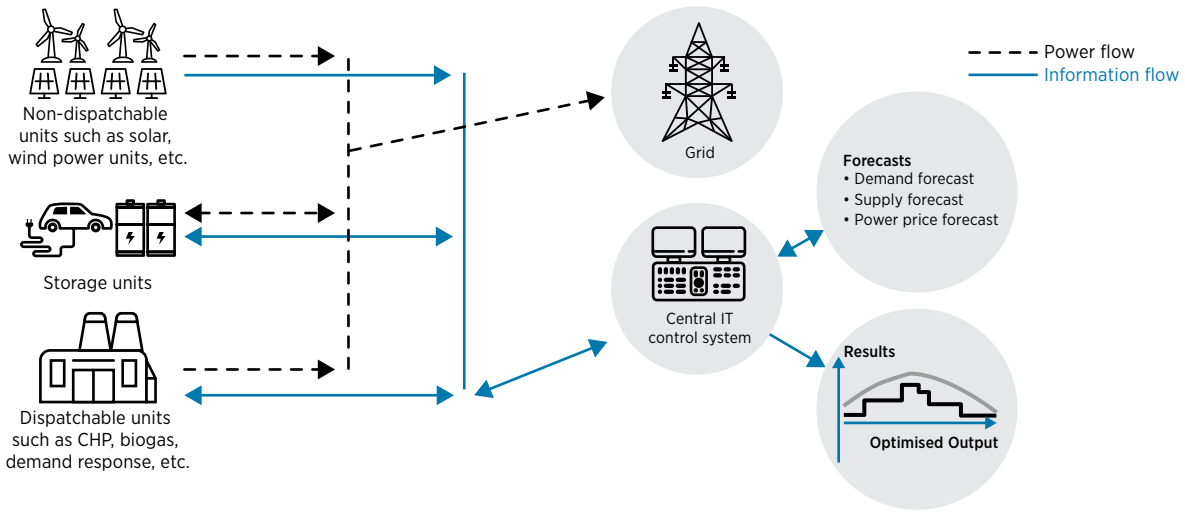
4. Key enablers of BTM energy storage

Certain enablers in the power system could increase the deployment of BTM storage. These are briefly described below with some practical examples.

Aggregators

The role of aggregators and the value they can provide to BTM storage should be noted. Aggregators are new market participants that operate a virtual power plant, which is an aggregation of dispersed distributed energy resources with the aim of enabling these small energy sources to provide services to the grid (IRENA, 2019c). Figure 63 is an overview of how an aggregator works.

Figure 63: Overview of an aggregator



Note: CHP = combined heat and power.
A central IT control system or a decentralised energy management (DEMS) sends an optimised schedule to the dispatchable distributed energy resources.
Source: IRENA (2019c).

Aggregators allow enhanced participation of BTM storage in the different electricity markets, help decrease the marginal cost of power and optimise investment in power system infrastructure; however, they require a proper regulatory framework and advance metering infrastructure in order to exploit their full potential. Examples of storage aggregators include:

- Eneco CrowdNett, as already introduced in the previous section.
- STEM, which is a California-based start-up that uses artificial intelligence and BTM storage to create a virtual power plant and reduce the cost of electricity for commercial consumers by providing different services, such as energy arbitrage (Stem, 2019).
- sonnenCommunity BTM Aggregation Model, which is a German aggregator from the battery company Sonnen allowing consumers to participate in grid services (Sonnen, 2019).

Time-of-use tariffs

Another important enabler for BTM storage is time-of-use (ToU) tariffs, which are also enablers of demand response. Time-of-use tariffs are time-varying tariffs that are determined according to the power system balance or short-term wholesale market price signals (IRENA, 2019e). These allow consumers to adjust their electricity consumption (including BTM storage) to reduce their energy costs.

ToU tariffs allow consumers to see when electricity prices are high or low, suggesting optimal times for charging a battery. There are different forms of ToU tariffs (IRENA, 2019e): static ToU pricing, real-time pricing, variable peak pricing, and critical peak pricing. Countries that have adopted ToU tariffs include Italy (static ToU tariff), Spain and Sweden (real-time pricing) and France (critical peak pricing).

High prices indicate a profitable time to discharge to the grid, thereby earning revenue from the gap between low-price charging and high-price discharging. To do this, however, net billing schemes are required.

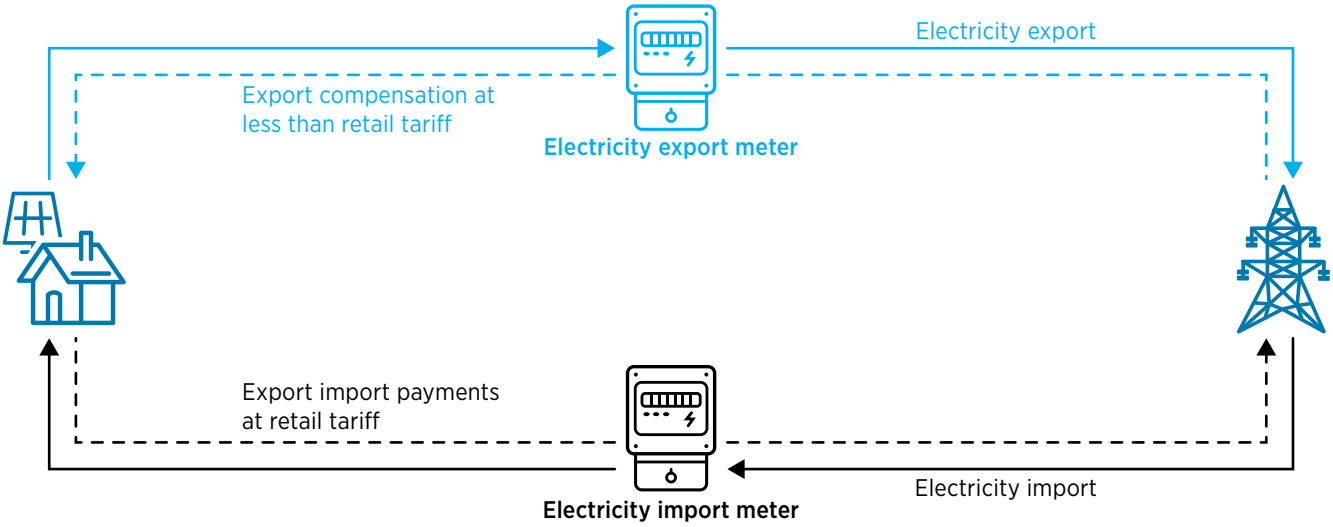
Net billing schemes

In order to obtain enough revenues to make the BTM battery a profitable investment, the battery needs to charge when prices are low (with ToU tariffs as explained above) and discharge when prices are high, so that the price differential generates sufficient revenues. To make this happen, traditional net metering schemes are no longer valid. Under net metering the total energy balance is calculated, and a total remuneration is paid or received after multiplying this balance by a specific price.

For storage to benefit from the price differential, one option is a net billing scheme, as explained by IRENA (2019f). Under net billing, compensation is based on the value of the kWh consumed or injected in the grid; it therefore allows the consumer to pay low prices when charging and receive high prices when discharging. Figure 64 shows the flow of electricity payments and electricity in a net billing scheme. Some countries have already implemented this kind of scheme in order to incentivise self-consumption.

In Italy, self-consumption is regulated by the "Sistema Efficiente di Utenza" (SEU), which sets the requirement to qualify as a self-consumption resource and benefit from specific advantages (exemption from payments or charges) (Sani, 2016). Additionally, if the resource is renewable and lower than 200 kilowatt peak, self-consumption resources such as storage can be subject to the "Scambio sul posto", which is a type of net billing

Figure 64: Schematic depicting flow of electricity and payments in a net billing scheme



Source: IRENA (2019f).

scheme that reimburses part of the bill for electricity consumed from the grid based on the excess of energy sold to the grid (GSE, 2016).

Other countries with net billing schemes are Mexico, Chile, Indonesia, Portugal and Germany.

Other enablers

Other enablers that incentivise BTM deployment are (IRENA, 2019d):

- The regulatory framework, in particular a liberalised wholesale electricity market without price caps (e.g. NYISO).
- Advanced metering infrastructure.
- Better generation forecasting.

5. Conclusions (Case 8: Behind-the-meter electricity storage)

In recent years the traditional grid paradigm has been shifting towards the smart grid, where consumers are allowed to use their own renewable energy and interact directly with the grid. In this context, to maximise self-consumption and benefit the consumer and the grid, BTM electricity storage such as batteries can be a critical resource. BTM can, on the consumer side, reduce electricity bills and demand charges and provide backup power, while on the grid side, provide flexibility and defer investment in the network and peaking plants.

BTM storage is already being deployed, for instance, in Germany where installations exceeded 100 000 in summer 2018, or in Australia, which in 2017 had 21 000 household batteries in place. There are also many specific BTM storage installations that have provided significant savings to the respective customer; for example, the Poway Unified School District's 6 MWh BTM storage systems is expected to save USD 1.4 million over 10 years.

A consistent and well-designed regulatory framework is needed to keep incentivising BTM storage deployment. Such a framework has to allow: a) the participation of aggregators, which can increase the value of BTM storage by providing services to the grid as a virtual power plant; b) ToU tariffs that will indicate the most economical times for storage to charge from the grid; and c) net billing schemes, which will increase the revenues that BTM storage can obtain by charging to and drawing from the grid.

6. Further reading

BTM batteries, artificial intelligence and big data, aggregators, ToU tariffs and net billing schemes are some of the 30 innovations considered in the IRENA Innovation Landscape Report. For more information read:

IRENA (2019), "Innovation Landscape Brief: Behind-the-meter batteries", International Renewable Energy Agency, Abu Dhabi.

IRENA (2019), "Innovation Landscape Brief: Aggregators", International Renewable Energy Agency, Abu Dhabi.

IRENA (2019), "Innovation Landscape Brief: Artificial intelligence and big data", International Renewable Energy Agency, Abu Dhabi.

IRENA (2019), "Innovation Landscape Brief: Time-of-use tariffs", International Renewable Energy Agency, Abu Dhabi.

IRENA (2019), "Innovation Landscape Brief: Net billing schemes", International Renewable Energy Agency, Abu Dhabi.

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