

Electricity Storage Valuation Framework:

Assessing system value and
ensuring project viability

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Electricity Storage Valuation Framework

Assessing system value and
ensuring project viability

Part 1. Why storage valuation matters

Part 2. Using power system models to assess value and viability

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

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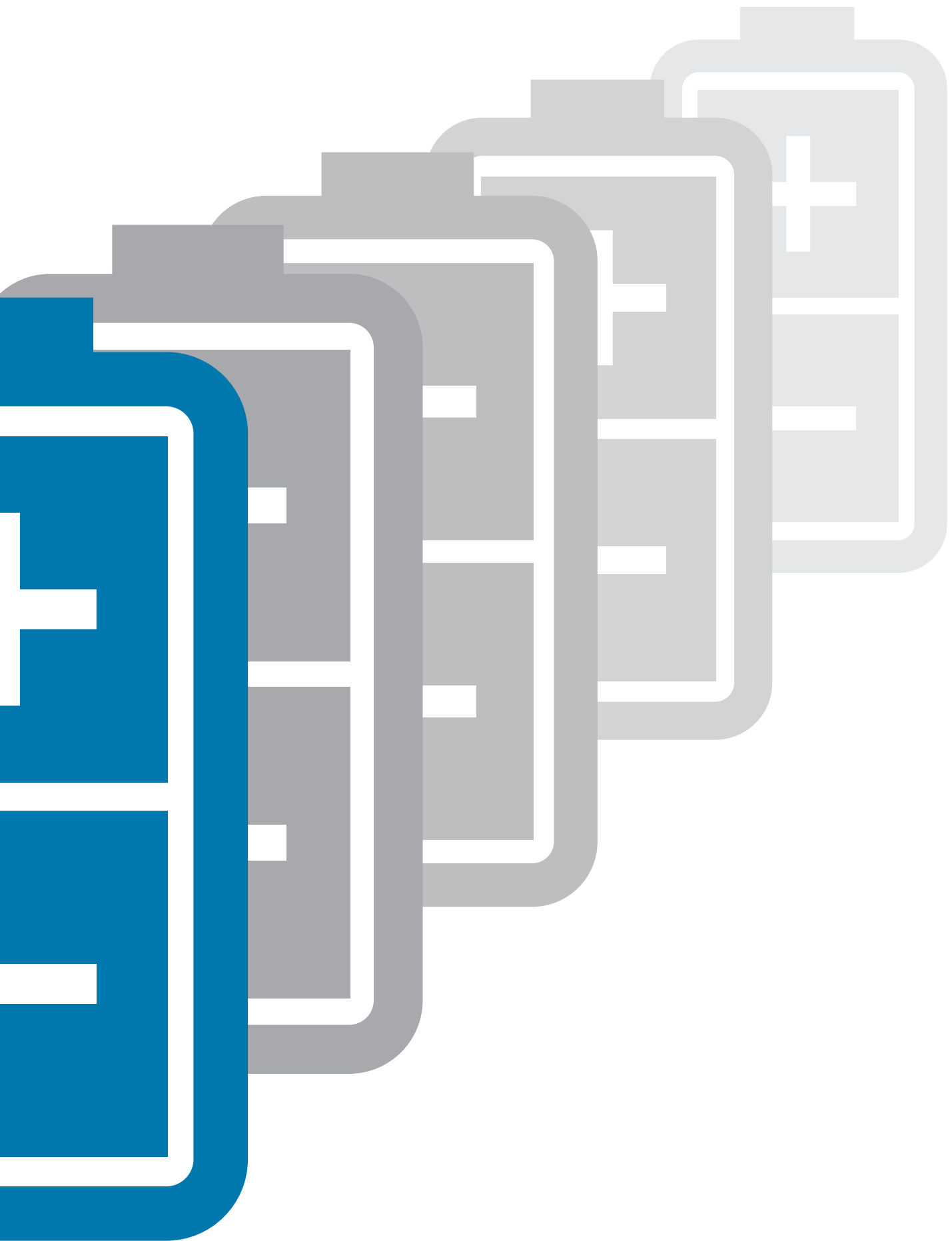
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Abbreviations

AC	alternating current
AEMO	Australian Energy Market Operator
APS	Arizona Public Service
BTM	behind the meter
CAES	compressed air energy storage
CAISO	California Independent System Operator
CAPEX	capital expenditure
CMP	Central Maine Power
COE	cost of energy
C-rate	charge (or discharge) rate of a battery
CSP	concentrated solar power
DAM	day-ahead market
DoD	depth of discharge
DSR	demand-side response
EFR	enhanced frequency response
ERCOT	Electric Reliability Council of Texas
ESS	energy storage system
ESVF	Electricity Storage Valuation Framework
EV	electric vehicle
FCAS	frequency control ancillary services
FCR	frequency containment reserves
FERC	Federal Energy Regulatory Commission
FFR	fast frequency response
FIP	feed-in premium
FIT	feed-in tariff
FOM	fixed operational and maintenance (costs)
FRD	flexible ramping down
FRP	flexible ramping product
FRU	flexible ramping up
HPR	Horndale Power Reserve
IRENA	International Renewable Energy Agency
IRR	internal rate of return
ISO	independent system operator
ITC	investment tax credit
kg	kilogram
kW	kilowatt
kWh	kilowatt hour

L	litre
LFP	lithium ferrophosphate, a type of battery chemistry
Li-ion	lithium ion
LMP	locational marginal price
LTO	lithium titanate, a type of battery chemistry
mBtu	million British thermal units
MISO	Midcontinent Independent System Operator
MW	megawatt
MWh	megawatt hour
MW/h	megawatt per hour
NaNiCl	sodium nickel chloride, a type of battery chemistry
NaS	sodium sulphur, a type of battery chemistry
NCA	lithium nickel cobalt aluminium, a type of battery chemistry
NMC	lithium nickel manganese cobalt, a type of battery chemistry
NPV	net present value
NYISO	New York Independent System Operator
OCGT	open-cycle gas turbine
OPEX	operating expenditure
O&M	operation and maintenance
PCS	power conversion system
PHES	pumped hydro energy storage
PV	photovoltaic
REC	renewable energy certificate
REE	Spanish electrical network (Red Eléctrica de España)
RoCoF	rate of change of frequency
RR	replacement reserves
RTM	real-time market
SOC	state of charge
SRMC	short-run marginal cost
T&D	transmission and distribution
ToU	time of use
VOM	variable operational and maintenance (costs)
VRB	vanadium redox battery, a type of flow battery
VRE	variable renewable energy
VRLA	valve-regulated lead acid, a type of battery
V2G	vehicle to grid
W	watt
Wh	watt hour
ZBB/ZnBr	zinc bromine battery, a type of flow battery



Executive summary

Renewable energy technologies have expanded rapidly in recent years because of steep cost reductions, innovation and policy support. The ongoing transformation of the power sector introduces new challenges that require changes in the way that policy makers, regulators and utilities plan, manage and operate the power system. The rapid expansion of renewable electricity calls for a more flexible energy system to ensure that a power system with large shares of variable renewable energy (VRE) resources can be operated reliably and cost-effectively.

With its unique capabilities to absorb, store and then reinject electricity, electricity storage is seen as a prominent solution to address a number of technical and economic challenges of renewables integration. **Electricity storage** can provide a wide range of services that support **solar and wind integration** and address some of the new challenges that the variability and uncertainty of solar and wind introduce into the power system. In a market setting, when allowed to participate in the wholesale market, storage can consume or feed in electricity in response to price signals, in particular increasing demand when prices are very low – or even negative. While **negative prices** could be a sign of inflexibility in the system, storage can prevent such phenomena from happening by consuming electricity and being paid to do so.

When coupled with solar photovoltaic (PV), storage can prevent the **cannibalisation of revenues** during the middle hours of the day,¹ increasing the profitability of solar PV and consequently creating the opportunity for more solar to be deployed. Solar PV generation can exceed electricity demand during the middle of the day; storage can absorb part of this electricity and reinject it at later stage, effectively **reducing curtailment** due to overgeneration or grid constraints. It can do this whether in a market or a vertically integrated setting.

Electricity storage services help to address the challenges of solar and wind variability

In addition, electricity storage can participate in capacity and ancillary services markets, **offering grid services** like provision of **primary and secondary reserves** as well as **firm capacity**. Indirectly storage can support cost reduction, **deferring the need for generation and transmission capacity** by reducing the need for peaking plants and easing line congestion. When connected behind the meter, electricity storage can support integration of distributed renewables and the active participation of prosumers in demand management, with resulting reductions in average household electricity bills. A key element is that storage can efficiently provide multiple services simultaneously, thereby **stacking revenues** for greater profitability.

Different storage technologies are intrinsically more suited to providing certain services rather than others. For instance, **batteries** have proven to be very **rapid in responding** to signals (e.g. set points from the system operator). This opens the way for new system services that have a higher value than conventional ones (e.g. one unit of fast frequency response can replace multiple units of primary reserve), effectively calling for a revision of grid services to capture the full value of new storage technologies.

When **large volumes** of electricity need to be shifted from one time to another (e.g. later in the day, week or month), **pumped hydro** has historically been the main technology to achieve this. Pumped hydro may therefore see a renaissance in solar and wind-dominated power systems, where new technologies such as variable speed pumping can provide additional system services in addition to simply bulk arbitrage.

Overall, electricity storage could play a key role in facilitating the next stage of the energy transition by enabling higher shares of VRE in power systems, accelerating off-grid electrification and indirectly decarbonising the transport sector. However, the **system value of storage** is often poorly accounted for in electricity markets, resulting in so-called **“missing money”** where market revenues for investors are insufficient to make projects viable, causing sub-optimal deployment of electricity storage. **In vertically integrated settings**, however, the **same entity can capture the full value of storage**, including savings in both production cost as well as investment, provided that the right incentives are in place to explore the potential of storage to reduce the cost of supply.

¹ Maximum generation from PV takes place when the sun is at its highest point – depressing electricity prices at this time. As additional PV further reduces prices during the middle hours of the day, more PV deployment leads to less revenues for PV generators, as most of their generation takes place during the hours with the lowest price.



The Electricity Storage Valuation Framework (ESVF) designed by the International Renewable Energy Agency (IRENA) and presented in this report aims to guide the development of effective storage policies for the integration of variable renewable power generation. The ESVF and its accompanying modelling methodology describe how to assess the value of electricity storage to the power system and how to create the conditions for successful storage deployment.

Report structure

This report describes IRENA's ESVF and its detailed methodology for valuing electricity storage. The report is organised into three separate parts:

Part 1 addresses **power system decision makers, regulators and grid operators**, aiming to give them with an overview of the process of valuing electricity storage in power systems. It provides an outline of the ESVF, describing its components and the sequence of steps that it uses to quantify the benefits of electricity storage and assess project viability under the existing regulatory framework. This part also describes the services that electricity storage can provide for the integration of VRE resources and identifies a number of storage uses to support VRE integration.

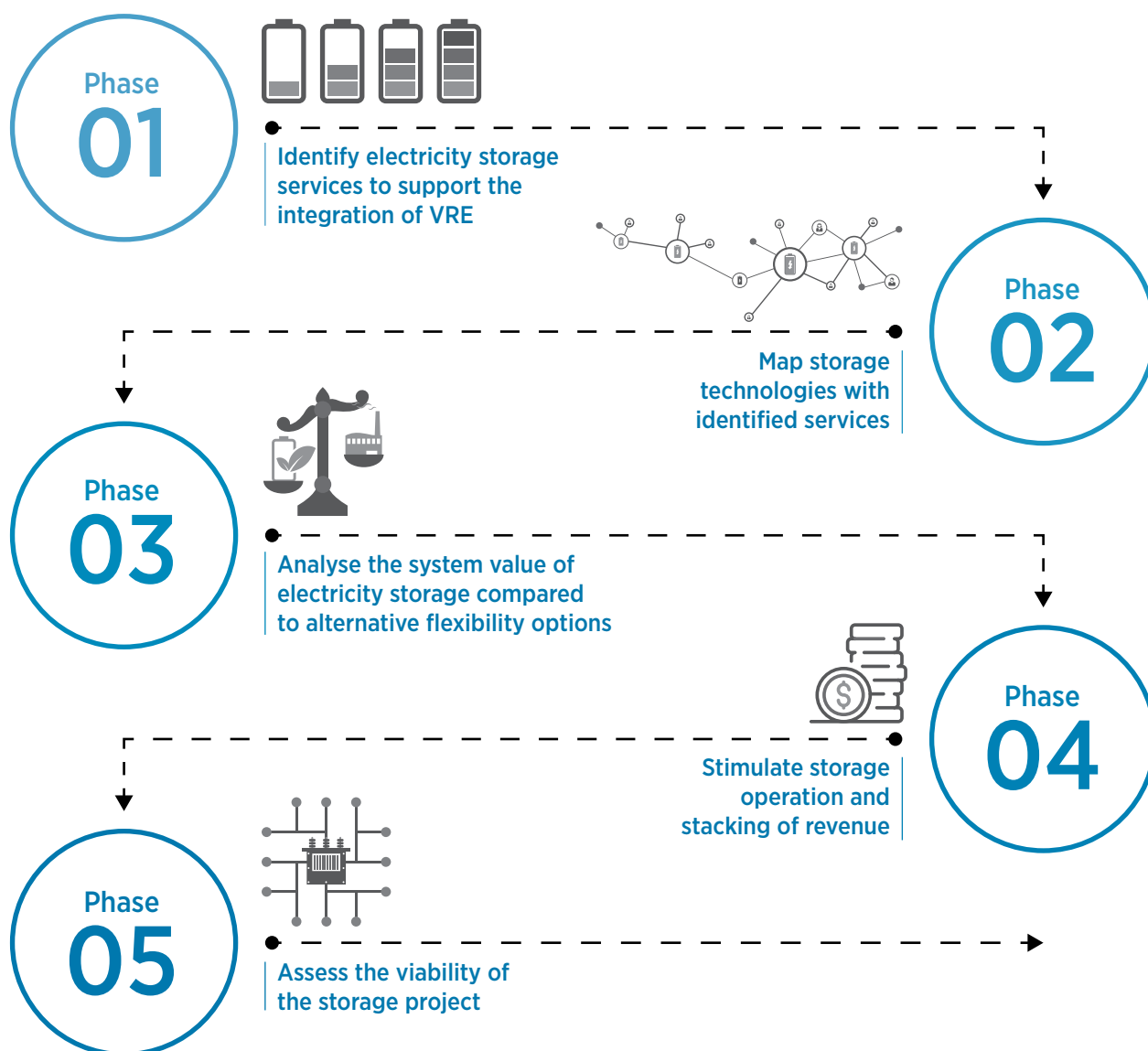
Part 1 also considers the role of the regulatory framework in supporting the development of storage projects that are demonstrated to be of net positive benefit to the power system, but may not see adequate revenues at the project level to justify being built. It allows the comparison of different measures by their effectiveness in supporting

the deployment of storage projects that are worthwhile pursuing (i.e. projects that cost less than the value they provide to the system).

Part 2 of the report 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 electricity storage valuation studies. Electricity storage valuation studies have recently been developed in support of a number of regulatory reforms. The methodology provided in Part 2 can be used for future studies, to provide consistency among them. Inputs and outputs for the various phases of the ESVF are discussed, including how to use power system modelling tools in each phase of the analysis. Particular attention is given to identifying and valuing benefits from the introduction of increasing amounts of electricity storage into the power system, and assessing the suitability of the regulatory framework to the deployment of the amount of storage projects that can provide value to the system.

Part 3 presents **eight real-world cases** of storage use, corroborated by examples of cost-effective storage deployment based on one main use and often supported by additional revenues derived from other uses. This part also highlights storage projects' ability to stack multiple revenue streams to reach commercial viability. These concrete examples are structured according to the following logical sequence: a) how such cases 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.

Figure: Electricity Storage Valuation Framework



Summary of report structure

Report Title	Type of content	Format	Target audience
Part 1: Framework overview	Overview of the process of valuing electricity storage in power systems	Brief report	Power system decision makers, regulators and grid operators
Part 2: Using power system models to assess storage value and viability	Detailed description of the ESVF methodology	Detailed report	Power system experts and modellers
Part 3: Real-world cases of storage use in power systems	Eight selected cases	Small briefs, one per case	Policy makers, energy planners, general public



Part 1: Framework overview

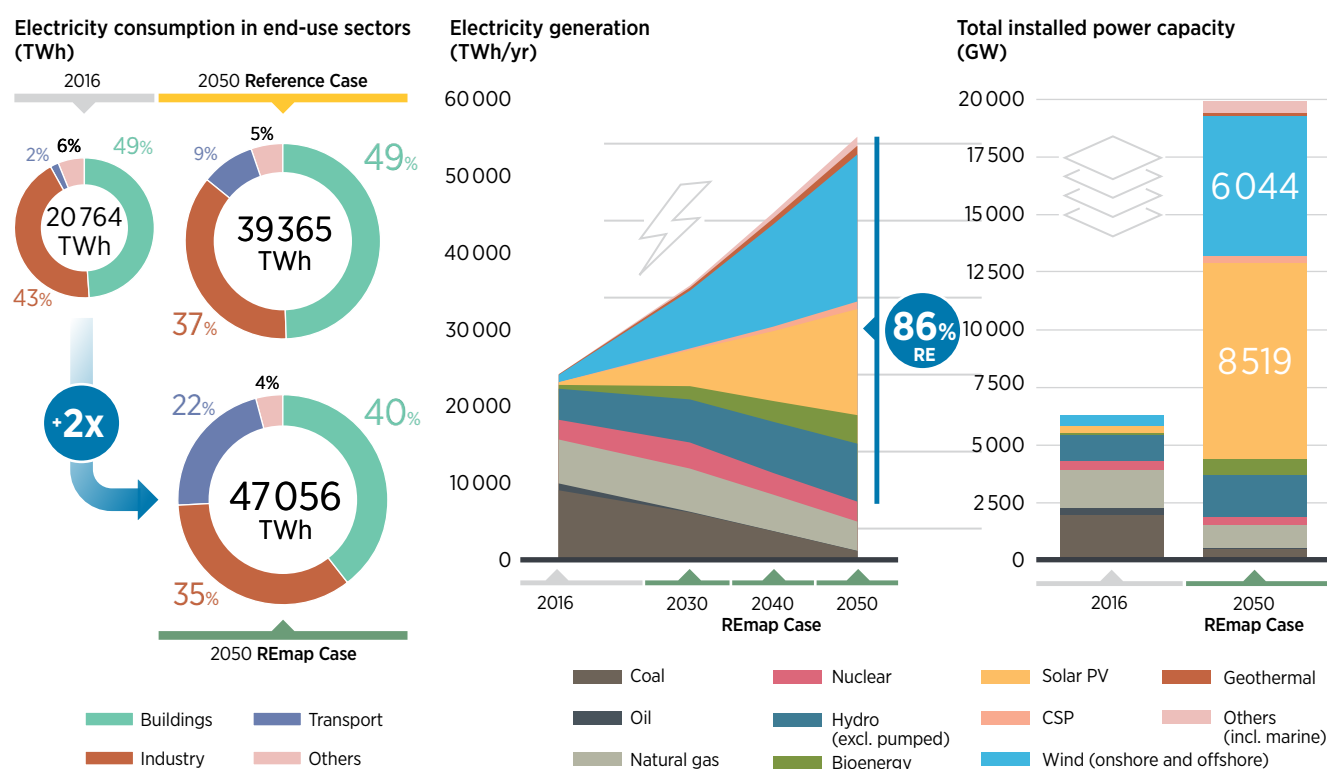
1. Introduction

Electricity storage refers to technologies that store electrical energy and release it on demand when it is most needed. The storage process often involves conversion of electricity to other forms of energy and back again.² With its unique ability to absorb, store and then reinject electricity, electricity storage³ is seen as a key solution for addressing the technical challenges associated with renewables integration alongside other solutions (e.g. more flexible demand, accelerated ramping of traditional power plants). Consequently, storage is garnering increasing interest in the power sector and is expected to play a key role in the next stages of the energy transition.

By enabling higher shares of variable renewable energy (VRE) in the system, storage capacity accelerates off-grid electrification and indirectly helps to decarbonise the transport sector.

Based on recent analysis by the International Renewable Energy Agency (IRENA, 2019a), the renewable share of global power generation is expected to grow from 25% today to 86% in 2050. The growth is especially strong for VRE technologies – mainly solar photovoltaic (PV) and wind power – with an increase from 4.5% of power generation in 2015 to around 60% in 2050. Furthermore, almost half of PV deployment could be achieved in a distributed manner in the residential and commercial sectors, in both urban and rural locations (IRENA, 2019a) (Figure 1).

Figure 1: Electricity generation mix and power generation installed capacity by fuel, REmap case, 2016–50

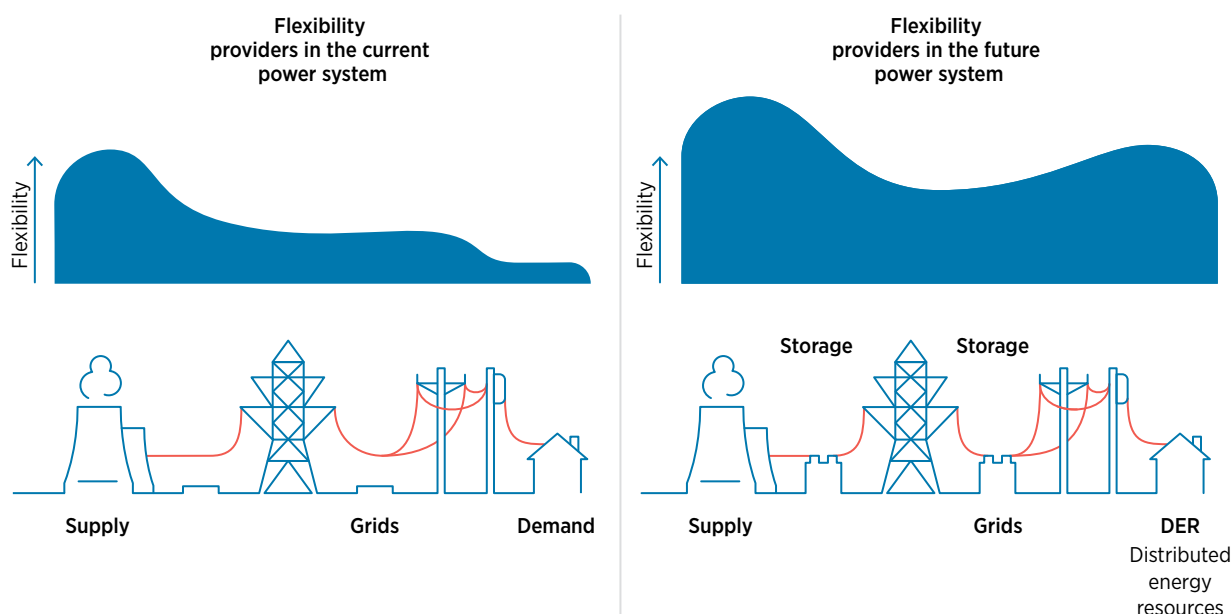


Note: IRENA's REmap case includes the deployment of low-carbon technologies, based largely on renewable energy and energy efficiency, to generate a transformation of the global energy system that limits the rise in global temperature to well below 2°C above pre-industrial levels. The assessment considers the renewable energy potential assembled from the bottom up, starting with country analysis done in collaboration with country experts, and then aggregating these results to arrive at a global picture; CSP = concentrated solar power; RE = renewable energy.
Source: IRENA (2019a).

² As in the case of pumped hydro where electricity is used to lift water to higher altitudes (converted to potential energy); when electricity is needed water is released to spin the blades of a hydro turbine and produce electricity. Examples of other electricity storage technologies include batteries, flywheels and compressed air energy storage (CAES).

³ This report refers to all energy storage technologies that can absorb and reinject electricity (i.e. batteries, flywheels, pumped hydro, CAES etc.).

Figure 2: Traditional flexibility providers (left) versus emerging flexibility providers (right)



Source: IRENA (2019b).

As renewable technologies mature, policy makers, regulators and utilities are confronted with new challenges related to planning, managing and operating the power system. The rapid expansion of renewable resources prompts the need for a more flexible energy system to ensure that variable resources can be integrated into the power system reliably and effectively.

Traditionally flexibility has been provided by conventional thermal generation with high ramping capabilities, low minimum loads or short start-up times, such as open-cycle gas turbines. However, to integrate very high shares of VRE, flexibility should be harnessed in all parts of the power system to minimise the total cost of providing flexibility (Figure 2). Electricity storage together with other mitigation measures (for example demand response, flexible generation, and smart transmission and distribution networks) could enable the integration of solar and wind power at very large scales (IRENA, 2018a, 2019b).

However, the pace at which electricity storage needs to be deployed in each of these cases varies depending on progress in the energy sector's transformation, the economics of alternative technologies that can provide similar or alternative solutions and progress in electricity storage costs and performance.⁴

The main barriers to large-scale storage deployment are:

- a. **Cost and technological maturity.** Battery costs are declining fast while technical parameters such as degradation rates and energy density keep improving. Deployment of batteries – both stationary and in electric vehicles (EVs) – is currently picking up; they are expected to play a key role in increasing flexibility in the energy sector, although in energy terms pumped hydro remains by far the largest source of electricity storage (IRENA, 2017a).
- b. **Difficulty for storage owners to monetise value.** There remains a lack of clarity around the monetisation and fair allocation of benefits of storage among stakeholders. This is due to the complex nature of power grids and dynamic interaction among system elements. Each power system has its own physical structure, electricity demand and, in the case of competitive environments, electricity market design and regulatory framework, meaning that no single solution fits all cases. Use of sophisticated tools and development of appropriate methodologies are needed to effectively guide policy makers on how to best develop appropriate policies to support monetisation of storage benefits among owners and stakeholders in general (IRENA, 2017a).

⁴ In deregulated markets, barriers can arise due to regulatory frameworks and electricity market design not being adjusted to compensate storage for the value it provides to the system.

The Electricity Storage Valuation Framework (ESVF) as presented in this report is a continuation of IRENA's previous work on the role of energy storage in facilitating VRE integration (IRENA, 2015a).⁵ The ESVF is designed to be used to identify the value of electricity storage to different stakeholders in the power system. It allows stakeholders to analyse both the value and challenges of implementing electricity storage systems. The framework considers: a) the value electricity storage brings to the power system; b) ways to optimally utilise electricity storage; and c) an approach to ensuring that the monetisable revenues for the identified amount of storage are higher than costs, to ensure deployment and reduction of total system cost.⁶

The ESVF addresses the first of these by identifying the services electricity storage can provide. Values are assessed by comparing the cost of operating the power system with and without electricity storage. The framework also describes a method to identify electricity storage projects in which the value of integrating electricity storage exceeds the cost to the power system. Because the value of electricity storage is realised throughout the power grid, often the project owner may not be able to earn revenues for all of the services the project is providing. This makes it difficult for the developer to economically justify the deployment of the electricity storage system. The ESVF can be used to support development of policies to support monetisation of the benefits of electricity storage based on their system value and fair allocation of such benefits among stakeholders. This report includes several recommended policy measures to provide incentives and compensation for the development of cost-effective electricity storage systems. These policy measures can be considered and applied on the basis of the results of the analysis.

More specifically, the **ESVF aims to address** the following questions:

- What services can storage provide to help integrate more VRE into the power system? What other peripheral services does the same storage provide?
- Which storage technologies can provide these services? What are the associated costs?
- How does storage compare with other alternative flexibility measures, such as demand response, more flexible generation or even stronger transmission networks, in effectively reducing total system costs?
- For the services that storage can cost-effectively provide, how should storage projects be deployed to realise the optimal benefits? Assuming optimal operation, would a project be financially viable under a specified market setting?
- Is there a missing money problem between the value storage provides to the system and the value realised by the storage owner? If yes, what are best policy recommendations to bridge the gap?
- How can analysis through a systematic approach support policy development to effectively answer the above questions?

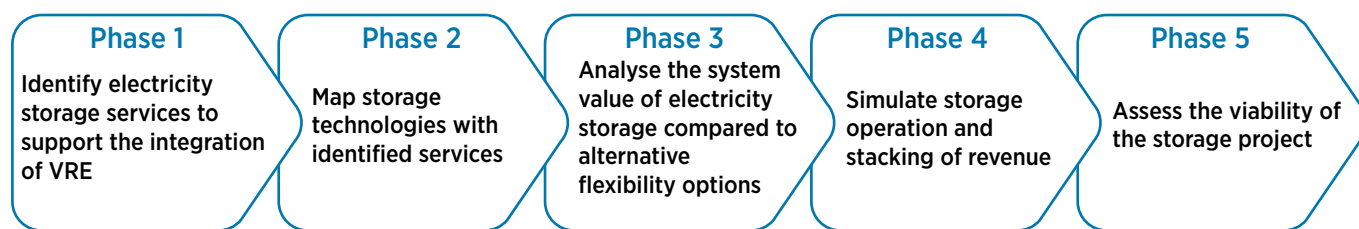
The framework **answers these guiding questions** in a sequence of five phases (Figure 3):

1. In **Phase 1** of the framework, the services that electricity storage can provide to integrate more VRE into the power system are identified. Categorisation of electricity storage services is partly based on previous IRENA work on electricity storage (see Box 1 and Box 2) (IRENA, 2015a; 2017a).
2. In **Phase 2** of the framework, the attributes of a variety of storage technologies are scored to rank their suitability to providing the services identified in Phase 1. This phase helps prevent the analyst from making the wrong choices for storage at the beginning of the modelling process.
3. In **Phase 3**, electricity storage is valued for its effectiveness in providing the identified services compared to alternative options such as energy efficiency, demand response and new fossil-fuelled power plants. The various services electricity storage provides at the system level eventually amount to a number of economic benefits of both an OPEX and a CAPEX nature that need to be estimated.
4. In **Phase 4**, the framework analyses the actual operation of a storage project, assuming the project is a price-taker under the market prices simulated in Phase 3. In this phase, the project revenue received is maximised by combining the various services the project can provide. This applies mainly in deregulated environments.
5. In **Phase 5**, the framework accounts for the revenue of the storage project over its lifetime, determines whether such revenues are sufficient to deem the storage project financially viable, and if not, how to identify possible remedies. The output of this final phase is a project-level cost and benefit analysis, where the cost refers to the costs of building and operating a storage project and the benefit refers to the combination of project-level and system-level benefits attributable to the project. In this phase, the result should be that monetisable revenues are adjusted to be higher than costs yet lower than the system value of the project.

⁵ See Box 1.

⁶ Total system cost in power systems planning refers to the total cost of physical infrastructure additions and operating a power system over the period of a study. It is often split into operating expenditure (OPEX) and capital expenditure (CAPEX) elements. The main component of OPEX is the cost of fuel to generate electricity. The main CAPEX component is the annualised investment costs over the period of the study.

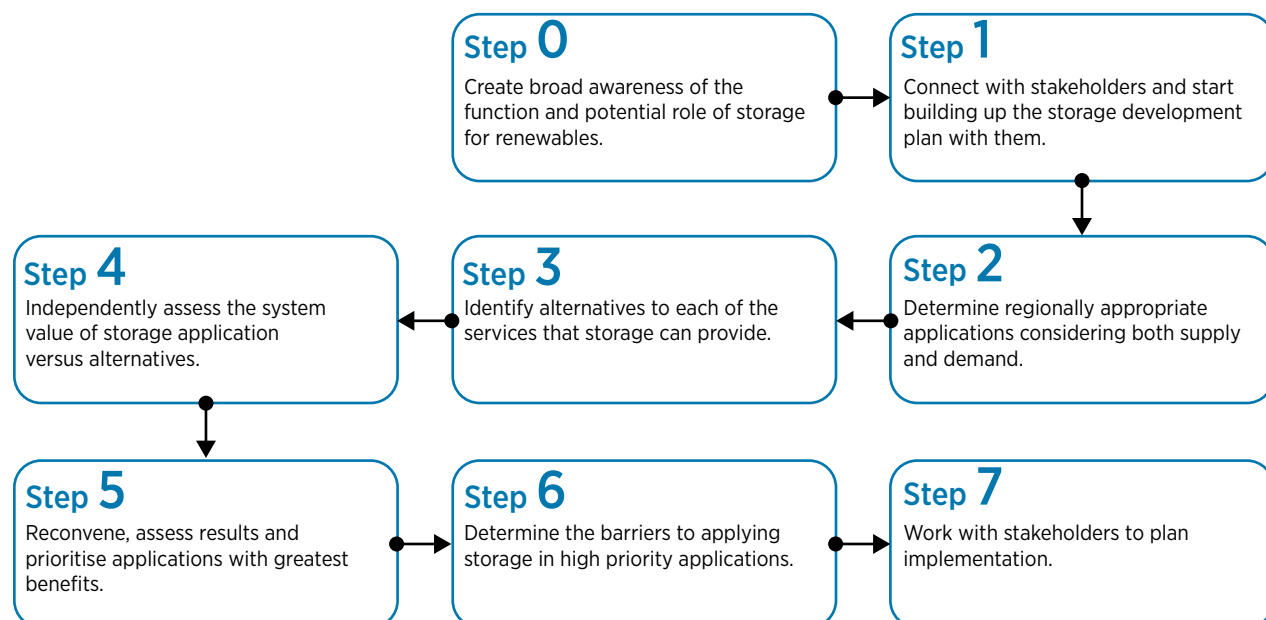
Figure 3: Electricity storage valuation framework: Five phases



Box 1: Renewables and electricity storage: A technology roadmap for REmap 2030

In June 2015 IRENA released “Renewables and electricity storage” (IRENA, 2015a), a report intended to provide a broad roadmap for developing electricity storage. This roadmap, based on a combination of literature reviews,

studies and findings from stakeholder workshops, highlighted priority areas for storage deployment, noted key areas for international co-operation and set out a framework to monitor progress.



This electricity storage roadmap identified 14 action items that were subdivided over 5 priority areas. These areas are:

1. **System analysis**, which helps to assess the role of storage in the power sector and is required by all countries.
2. **Storage on islands and in remote areas**, which is the most immediate area where electricity storage can support renewable energy deployment.
3. **Consumer-located storage**, which is relevant for countries expecting a high share of rooftop solar PV systems in the power sector.

4. **Generator-located storage**, which is important for countries in categories 1 and 3.

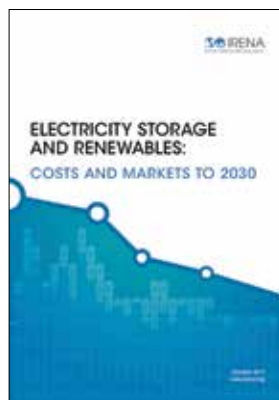
5. **Storage in transmission and distribution grids**, which is relevant for countries making the transition to power systems based on renewables but with limited power system flexibility.

The present report aims to address the priorities that IRENA identified in 2015 by developing the IRENA ESVF with a methodology to systemically assess the value of electricity storage and to engage and guide policy makers. The figure in this box shows the steps identified in the 2015 report for engaging and guiding stakeholders in developing energy storage policies for renewables. The present report provides a framework and a methodology to address steps 3–6 in the process.

Box 2: Electricity storage and renewables: Cost and markets to 2030

The electricity storage roadmap launched by IRENA in 2015 identified that two of the most important elements to be considered when assessing the economics of electricity storage are costs and value. In October 2017 IRENA launched the report “Electricity storage and renewables: Cost and markets to 2030” (IRENA, 2017a) in order to analyse the current and future costs of electricity storage.

Some of the main findings of this report are that the rapid deployment and commercialisation of new battery storage technologies have led to rapid cost reductions, notably for lithium-ion batteries. However, battery electricity storage still offers enormous deployment and cost-reduction potential. By 2030 the total installed costs could fall by between 50% and 60%, driven by optimisation of manufacturing facilities, better combinations and reduced use of material.



Apart from costs, the report also maps the different services that storage can provide to the grid and the main parameters of different battery storage technologies. A tool* was also made available online to perform a quick analysis of the approximate annual cost of electricity storage for different technologies in different applications.

This IRENA report covers half of the most important elements needed to economically assess electricity storage: the costs. To analyse the value of electricity storage in different power systems and complement the 2017 costing report, IRENA has developed the ESVF being described in the present report.

* Download the tool here: <https://irena.org/publications/2017/Oct/Electricity-storage-and-renewables-costs-and-markets>.

The ESVF has been designed as an instrument to inform policy making on the basis of detailed and complex analysis. Such analysis requires the use of a) a large amount of data, and b) appropriate optimisation tools. An analyst wishing to apply the ESVF will need to choose between relevant modelling tools with different capabilities and costs, and at the same time develop models/study cases that are both representative of reality (i.e. assumptions are reasonable, data are accurate) and practical (i.e. do not require unreasonably large amounts of data, have reasonable running times).

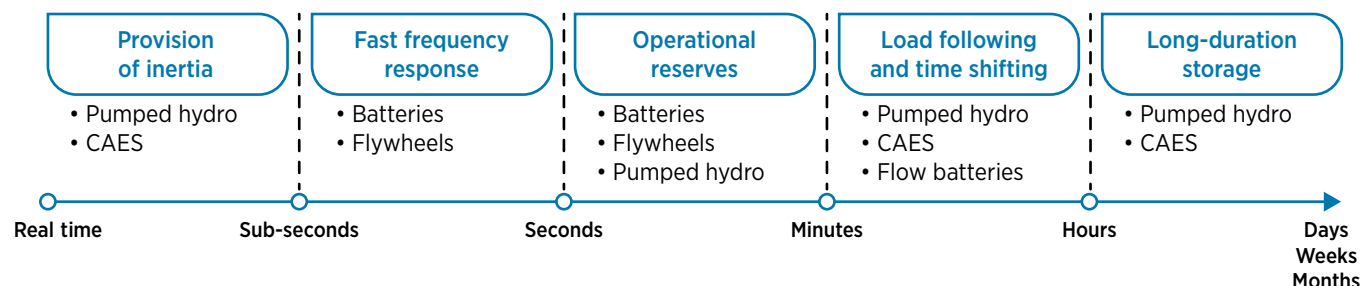
2. The role of electricity storage in VRE integration

Since the first quarter of the 20th century electricity storage, mainly in the form of pumped hydro, has been used to provide a wide range of grid services that support the economic, resilient and reliable operation of power systems. The great majority of global electricity storage capacity deployed up to the present day is pumped hydro due to its favourable technical and economic characteristics (IRENA, 2017a). Over the last hundred years, the electricity storage industry has continued to evolve and adapt to changing energy and operational requirements and advances in technology.

In addition to pumped hydro, a number of electricity storage technologies with varying costs and technical affinity for providing specific services have emerged and are currently at different stages of maturity and deployment. Such technologies include, for example, solid batteries, flow batteries, flywheels and compressed air energy storage (CAES). The various services electricity storage can potentially offer to support grid operations have often been grouped under energy services, ancillary services, transmission and distribution infrastructure deferral and congestion relief, and customer energy management services (Sandia National Laboratories, 1993, 1994, 2010; EPRI and US DOE, 2003; CAISO, 2007; DOER and MassCEC, 2016; ENTSO-E, 2016; EASA and EERA, 2017) (see Figure 6 below and Part 3 of this report, which provides examples of applications of electricity storage for eight different cases).

Recent developments have greatly increased interest in electricity storage. These include advancements in storage technologies and reductions in storage costs (for lithium-ion batteries in particular), the development of liberalised electricity markets and markets for ancillary services, challenges in building new transmission and distribution infrastructure, the enabling role that storage can play in solar and wind replacing diesel generators in an off-grid context, and the need for solutions to integrate the large amounts of VRE being deployed in power systems.

Figure 4: System services that electricity storage can provide at varying timescales



Electricity storage is expected to play a critical role in facilitating the integration of VRE into power systems and the energy transition more generally (IRENA, 2018a, 2019b). Integrating high shares of VRE is challenging due to its inherent characteristics. More specifically, variability and uncertainty related to solar and wind resources pose technical challenges for the process of balancing supply and demand, which in turn increases the need for system flexibility. Increasing system flexibility requires a range of measures, with storage being one of them. Others include flexible generation, demand-side management, smarter and stronger transmission and distribution networks, and sector coupling (e.g. hydrogen production from renewable energy⁷ and vehicle-to-grid flexibility) (IRENA, 2018a, 2019b). As explained in more detail in other parts of this report, the ESVF is designed to compare electricity storage against alternatives considering both technical suitability to providing the intended service and cost-effectiveness.

Integration of VRE has direct impacts on system operations as it affects the magnitude of grid services needed as well as the timing and operational profile of each service. The impacts of VRE are characterised by a range of timescales that extend from sub-seconds (for example, when a cloud passes over a PV plant in a small power system) to years (the lead time of new transmission lines to ease congestion). Thus, to be effective for a specific application a storage technology needs to have the appropriate technical characteristics, namely response time, power capacity and energy capacity (Denholm et al., 2010) as well as synchronous inertia capabilities. The latter is very important in the context of VRE integration, as very high shares of non-synchronous VRE generation can undermine system stability without the use of appropriate measures.

At the shortest timescale (sub-seconds) certain storage technologies, such as pumped hydro, can provide inertia as a first line of defence in case of sudden loss of generation and can reduce a system's dependence on thermal generators to limit the rate of change of frequency. From sub-seconds to seconds, electricity storage (mostly batteries, but also in specific applications flywheels) is

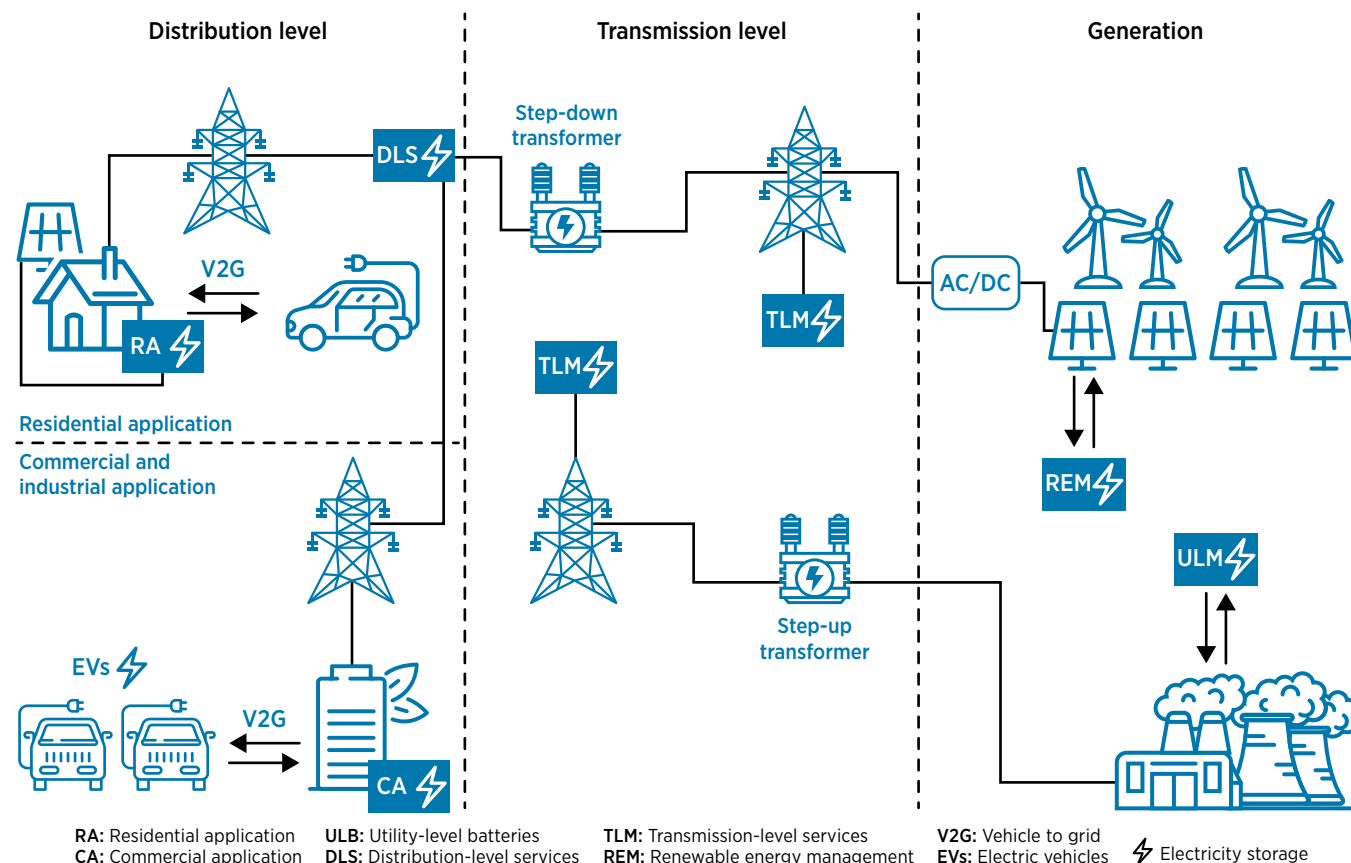
suitable for providing fast frequency response, which is currently being implemented as a service in some power systems (e.g. United Kingdom). At a timescale of seconds to minutes, storage has been used mainly for the provision of operational reserves (mainly batteries, flywheels and pumped hydro). From minutes to hours pumped hydro, CAES and flow batteries can be used for load following and time-shift of energy (energy arbitrage), and from hours to days, weeks or even months electricity can be stored in long-term electricity storage,⁸ which is necessary at very high VRE penetration (Figure 4).

Notably, while the ESVF can be used to compare costs and benefits of electricity storage against other flexibility alternatives at a system level (Phase 3 of the framework), full implementation of the ESVF (Phases 1 to 5) provides insights specific to electricity storage; in other words, the ESVF is not designed to provide policy recommendations for alternatives to electricity storage.

The services that electricity storage can provide depend on the point of interconnection in the power system. For example, when connected to the grid at the transmission level, electricity storage can support increasing shares of VRE (as explained above), participate in electricity market bidding to buy and sell electricity, and provide ancillary services at the various timescales relevant to technical capabilities of each technology. When connected at the distribution level, electricity storage can provide all of the above services and in addition can be used to provide power quality and reliability services at the local substation, defer distribution capacity investment, and support integration of distributed renewable energy. It can also be connected to other generation facilities, allowing for higher price capture, provision of grid services and at the same time savings on connection costs. Finally, electricity storage can be placed behind the meter (Figure 5) to support a customer in increasing PV self-consumption, thereby reducing electricity bills (where time-of-use demand-side management schemes exist), improving power quality and reliability, and potentially enabling participation in energy management, wholesale and ancillary services markets through aggregators (EPRI and US DOE, 2013; RMI, 2015; IRENA, IEA, REN21, 2018).

⁷ The framework focuses only on electricity storage options. Specific sector-coupling options like hydrogen production (seasonal storage of electrofuels), heat pumps and electric boilers (thermal storage) are not addressed in this report.

⁸ Although the framework is about electricity storage, power-to-hydrogen and power-to-heat are likely to be key for the provision of long-duration energy storage, with hydrogen being a large-scale storage option with the potential to go back to electricity (although inefficiently).

Figure 5: Grid applications of energy storage

Physical location and operational mode (coupled with generators or standalone), along with the regulatory environment and market structure under which electricity storage operates, greatly affect the type of analysis needed to estimate both system-wide and project-wide benefits of electricity storage. These considerations are explained in more detail in Phase 3. For example, electricity storage can be operated as a standalone unit or co-located with generation facilities, e.g. solar PV and wind farms. In the case that storage is co-located with a PV farm, rather than being a standalone unit it is an asset of a “hybrid power plant”.⁹

Electricity storage can mitigate the impact of VRE variability and uncertainty simply by providing grid services. The California Independent System Operator (CAISO) describes how storage can, for example, bid to supply ancillary services by providing frequency regulation and operating reserves to restore frequency imbalances related to VRE uncertainty, or by providing load-following services bridging the gap between real-time unit commitment and real-time dispatch (NERC and CAISO, 2013). Storage can be used to shift the time of VRE delivery by essentially charging when wind is blowing (in many but not all cases, wind production is higher at night-time when electricity prices are low) and

discharging during peak hours to maximise revenue. Similarly, it can potentially increase the capacity credit of VRE by allowing it to participate in capacity markets and potentially defer the need for conventional capacity.

Electricity storage can also be used to support integration of VRE by reducing variability and generation forecast error and improving power quality. Potential cost savings, for example, can result from a reduction in penalties imposed by the operator where there is a restriction on maximum ramp induced by generators, or from avoiding penalties related to unbalancing (failing to provide the amount of energy bid into the market). In addition, with appropriate mechanisms in place, the VRE/storage owner can offer system-wide benefits by providing area regulation (Sandia National Laboratories, 2010). Notably, in a vertically integrated utility, storage should ideally be installed where its value to the system is the highest,¹⁰ while in liberalised markets there might be an incentive for generators or consumers to install storage to maximise their revenues, which might not translate into the highest system value for that given amount of storage. In specific settings (e.g. South Australia and Hawaii) auctions calling for combined solar PV and storage have been used to deploy “system-friendly” VRE projects.

⁹ The ESVF is designed to assess the value of electricity storage as standalone plant only.

¹⁰ In reality utilities do not always operate in a way that maximises system benefit; this can happen due to technological conservatism, outdated regulations, lack of proper planning capacity etc.

Finally, the maximum project value from electricity storage is obtained when the operation is co-optimised to provide multiple services.¹¹ Numerous studies have used data from electricity markets that confirm that investing in electricity storage for just one service, e.g. for arbitrage, frequently does not pay back the investment. However, when it provides additional services, for example a variety of ancillary services in parallel with arbitrage, and these multiple services are monetised, then profits are greatly improved (Nikolakakis and Fthenakis, 2018; Drury, Denholm and Sioshansi, 2011; Sioshansi et al., 2009; Salles et al., 2017; Teng et al., 2015; Zakeri and Syri, 2016). The ESVF described in this report puts emphasis on the need to optimise storage operation for multiple services, stacking different types of potential benefit to assess the optimal value.

3. Methodology

The ESVF is a guide for decision makers to identify the value of storage on an electricity grid with increasing VRE penetration, exploring a variety of possible applications and mechanisms to make storage projects viable. Notably, the ESVF is mostly useful for assessing the value of storage to the power system as a whole. It allows for comparison of storage deployment costs, while identifying a) optimal amounts of additional storage to minimise total system cost; b) viability of storage projects based on the existing regulatory framework and a set of possible uses; and c) regulatory measures that might facilitate deployment of storage, at a cost not exceeding system-level benefits.

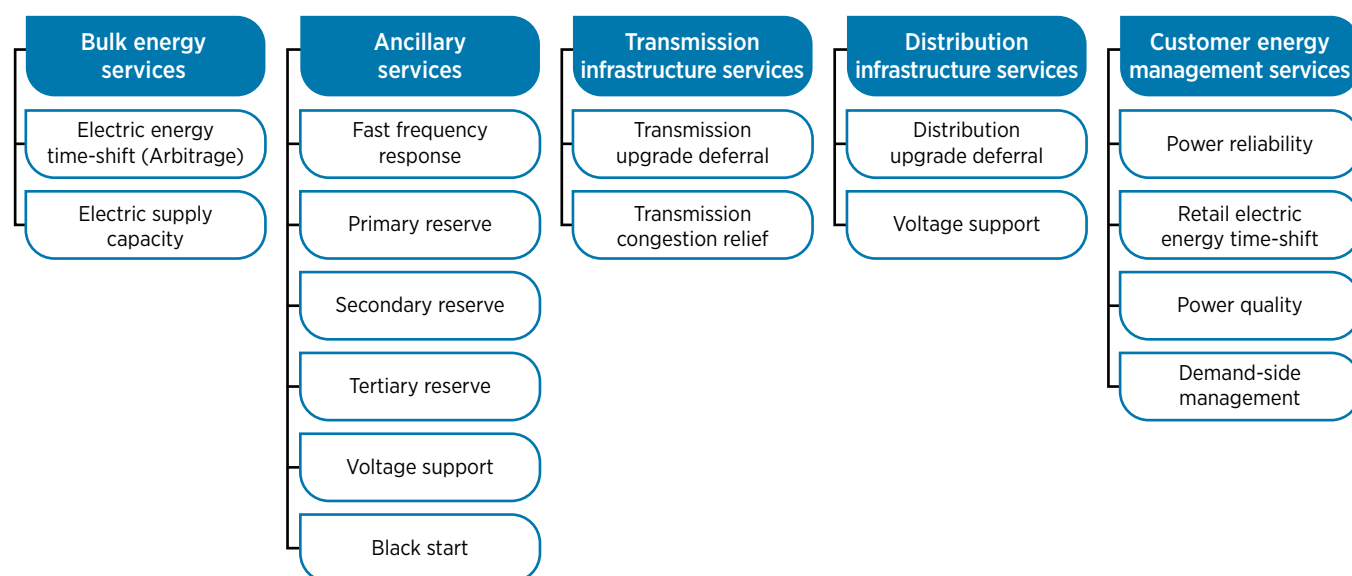
The ESVF starts in Phase 1 by highlighting the services from storage that are relevant to VRE integration in a specific context (e.g. country, plan, regulatory framework). Such services can subsequently be grouped together to strengthen project viability. Based on this, a mapping of the technologies best suited to provide such services is performed, giving a tentative ranking by applicability (Phase 2). Phase 2 aims to prevent the analyst from making unsuitable choices for storage at the beginning of the modelling process. These two phases can be conducted in a simple analytical environment (e.g. spreadsheet), while the following phases require modelling tools capable of performing optimisation.

Phase 3 requires a dispatch of the power system to assess the value of storage. This is complemented by a least-cost investment phase to compare storage with alternative flexibility options. Once the optimal amount of storage and other flexibility measures are identified, a set of data in Phase 3 (for example electricity prices) can be used to simulate storage operation in Phase 4. This phase shifts the focus from system-level to storage-focused analysis, by taking the outputs of Phase 3 as inputs and reoptimising storage dispatch to maximise the revenues from multiple services that storage can provide. Finally, these revenues are compared with system value from Phase 3 in the final phase of the ESVF, Phase 5. In this last phase, project viability is assessed by looking at the gap between monetisable revenues and project cost. This allows the comparison of alternative regulatory measures to solve the missing money problem often associated with new technologies, which were not considered when the market they are entering was designed. More detailed discussion about the phases of the ESVF follows below.



Photograph: Shutterstock

¹¹ Apart from the stacking of multiple services, there is the value of “dual participation”, which is applicable to behind-the-meter storage and means the value of behind-the-metre storage in providing both grid services and individual services (i.e. to the household in which it is located).

Figure 6: Electricity storage services and their relevance to renewable power integration

Phase 1: Identify electricity storage services supporting the integration of VRE

Phase 1 of the framework identifies the services that electricity storage can provide to integrate more VRE into the power system. The list of services, as presented in Figure 6, is based on studies that categorise electricity storage options according to their ability to support grid services, that is, to release energy, provide firm capacity, defer the need for investment, support customer energy management and directly support integration of VRE (EASAC, 2017; EPRI and US DOE, 2013; Southern California Edison, 2013; EASA and EERA, 2017).

From the services presented in Figure 6, the following are recognised as contributing to VRE integration in either direct or indirect ways (although their value and definition varies from country to country depending on grid infrastructure and market design): wholesale energy time-shift, energy supply capacity, fast frequency response, primary and secondary reserves,¹² frequency regulation, transmission and distribution upgrade deferral, capacity investment deferral, retail energy time-shift and power reliability (including supporting voltage through reactive power injection, possibly black start services). For example, behind-the-meter storage can support both integration of distributed energy sources and active participation of prosumers in overall energy management (RMI, 2015). However, in order for its full value to be realised, the operator of the distribution system needs to have a more active role and prosumers need to be able to participate in the various energy markets through a number of schemes, as in the case of the aggregators (IRENA, 2019b).

As noted in Section 2 above, electricity storage can indirectly provide secondary services in parallel to its originally planned primary role. Thus, the contribution of electricity storage to facilitating VRE integration might be indirect. For example, a standalone pumped hydro unit performing services such as electricity arbitrage (buying electricity when it is cheap to sell when its value is high), fast load following, frequency response or provision of inertia, could also be reducing VRE curtailment at the same time. Similarly, a CAES unit co-located with VRE and having as its primary role maximising the profit of the hybrid plant (for example via provision of firm capacity, energy arbitrage and ramping control) could also indirectly defer the need for peak capacity and reduce the need for ancillary services.

Service identification is a one-time¹³ exercise to define the types and specifications of services that storage can provide, so that the methodologies to evaluate the cost-effectiveness of storage can be developed. Phases 3 and 4 might need to be repeated to extract valuable insights. Moreover, a significant portion of storage value is expected to come from deferral of other investments, such as peaking plants or transmission and distribution (T&D) investment, especially in systems where electricity demand is growing or where VRE constitutes a significant share of electricity generation.

Such considerations are discussed in more detail in the explanation of Phase 4. The ESVF allows the feasibility of multiple value streams to be assessed. The services electricity storage can provide, as detailed in Phase 4, are grouped into cases. In each case, electricity storage will provide a combination of services; each service in the

¹² The terminology around ancillary services varies in different parts of the world.

¹³ As new technologies and services are developed over time, mapping of storage technologies is subject to change in the future. However, it only needs to be assessed once at the beginning of a storage valuation exercise for a given project.

case must be compatible with the others so that double counting is avoided. To construct a case, a storage asset's primary function is often considered first, while other services are secondary. For example, electricity storage can perform energy arbitrage, but the same asset could reserve some capacity to provide other types of service at the same time, such as primary reserve. The provision/ allocation of services is the subject of optimisation in Phase 4.

Phase 2: Mapping of storage technologies with identified services

The storage services identified in the previous phase are complemented by a comprehensive analysis of the technical and commercial parameters of prevailing electricity storage technologies to determine those suitable for each service. In this phase, scores are assigned to different technologies by weighting technical attributes against their relevance in specific applications, and the resulting matrices are used to evaluate how suitable a specific technology is in a certain application. The outcome of this phase is a ranking of storage technologies based on their technical affinity to provide the services defined in Phase 1.

Based on IRENA (2017a), the key techno-economic parameters of selected electricity storage technologies are considered, as listed in Table 1.

Depending on the application for which the technology is considered, the parameters should be weighted according to their importance for each application. After this, each technology can then be scored in terms of its suitability for each application, by calculating a weighted average of the ranking of each techno-economic parameter for that application.

Table 1: Techno-economic parameters for electricity storage suitability assessment

Technical
Efficiency (AC-to-AC) (%)
C-rate minimum
C-rate maximum
Maximum depth of discharge (%)
Maximum operating temperature
Safety (thermal stability)
Economic
Storage CAPEX (USD/kWh)
Power converter CAPEX (USD/kW)
Development and construction lead time
Operating cost (USD/kWh)
Energy density (Wh/kg)
Energy density (Wh/L)

Notes: AC = alternating current; kW = kilowatt; kWh = kilowatt hour; Wh/kg = watt hour per kilogram; Wh/L = watt hour per litre.

Phase 3: Analyse the system value of electricity storage compared to alternative flexibility options

One of the goals of the ESVF is to assess electricity storage against other flexibility options. Typically, this happens in Phase 3 of the framework. While electricity storage is a key technology to decarbonise the energy system (Sisternes, Jenkins and Botterud, 2016; IRENA, 2018a), there might be specific cases where it is not competitive against alternatives. In Phase 3 electricity storage is valued both for its effectiveness in providing identified services and its economic attractiveness compared to alternative options. Alternative technologies could be, for example, other flexibility sources like demand response and flexible generation, or even enhancement of the transmission network (the latter would require a model that optimises transmission together with generation). The comparison is performed through a combination of least-cost capacity expansion optimisation and production cost modelling.

Capacity expansion optimisation is a methodology widely used to identify long-term least-cost pathways in the power sector through appropriate optimisation tools and relevant inputs. The objective of the analysis is to identify the least-cost investments that meet the projected profile of electricity demand (current or future demand) of a power system subject to technical and applicable policy constraints.

While capacity expansion software estimates operational costs, it will not usually be able to do so within a timeframe representative of real-time operations (i.e. modelling system operation at the sub-hour level as in the case of intraday markets and sub-hourly dispatch). For that reason, the simulation within the capacity expansion software is integrated with production cost simulation software, to estimate accurately the operational costs of a power system. Production cost optimisation is a computational method to simulate the unit commitment and economic dispatch of the generation fleet of a power system over time steps of an hour or less.

Optimisation of investment needs to consider a number of real-world constraints, as in the case of policy goals (e.g. CO₂ targets), fuel availability and system reliability (i.e. any changes in the physical structure of the system should not compromise system reliability). The basics of power system optimisation are discussed in detail in IRENA (2018a). In addition, IRENA has developed an open-source tool, called the IRENA FlexTool, capable of performing both capacity expansion and production cost optimisation with a focus on power system flexibility. The FlexTool is also capable of comparing electricity storage with other flexible options as in the case of EVs, electric boilers, heat pumps and hydrogen production (IRENA, 2018b).

The ESVF's approach to estimating the system-wide value of storage comprises the following steps:

- **Step I:** To identify optimal investments, electricity storage is considered together with alternative technologies (such as energy efficiency, demand response, new transmission and peaking power plants) in a least-cost capacity expansion optimisation. Production cost simulations are needed for an accurate estimation of the value and optimal amount of storage, as well as the costs of storage to the system over the period of study (one or multiple years).¹⁴
- **Step II:** Step I above is repeated with storage removed from the available options (the alternative technologies mentioned in Step I are included). The capacity expansion analysis will provide a set of alternative solutions to serve system needs. Production cost simulation is used to estimate operational costs accurately.
- **Step III:** A comparison of total system costs from Steps I and II gives the total system value of storage over the period of study. Phase 3 will only deploy electricity storage if this is beneficial for the system; the difference compared with the “no new storage” scenario is deemed to be the benefit of adding electricity storage to the system.

In general, the main types of benefits that can be estimated by following the methodology proposed above relate to cutting OPEX costs and lowering CAPEX investment needs. These factors are outlined in Table 2.

1. **Savings in CAPEX** from deferring the need for alternatives (including peak capacity, demand response and transmission infrastructure). Savings in CAPEX are estimated by comparing the results of capacity expansion optimisation between the “with storage” and “without storage” scenarios.
2. **Savings in OPEX.** OPEX reductions can be estimated using the results of the production cost models. Typical production cost models are capable of isolating various OPEX types, namely fuel costs (including start-up costs), variable operation and maintenance (O&M) costs, reliability costs (i.e. cost of unserved energy), VRE curtailment costs (depending on market setting) and, when applicable, the cost of emissions.¹⁵ In high VRE scenarios, the main cost reductions come from fuel savings. Table 2 categorises the various storage benefits according to whether they are OPEX or CAPEX in nature.

Deployment of electricity storage can additionally bring a number of indirect cost savings to the system and society in general. These could relate to system reliability (e.g. when storage provides inertia to the system) or even system security (e.g. when storage supports penetration of renewables and as a result energy independence, as in the case of countries that lack natural resources). These might be difficult to quantify. More detailed discussion about quantifiable benefits of electricity storage and other issues related to the complexities of modelling and scenario development follows in Part 2.

Table 2: Electricity storage benefits from Phase 3

OPEX	Reducing costs for producing electricity, including fuel consumption, variable O&M, and start-up and shutdown costs, by: • Replacing energy generation during peak • Replacing load-following cycling thermal generation • Replacing other sources of ancillary services • Reducing congestion • Increasing VRE penetration.
CAPEX	Reducing the cost of capital investment by: • Deferring the need for peaking capacity • Improving the capacity factor of VRE (less VRE capacity needed to achieve climate goals) • Deferring the need for T&D capacity.

¹⁴ Even if storage is no better than the alternatives, this does not mean it brings no value to the system. It simply means alternative solutions can perform the needed services at less cost. In addition, even if storage is not used in system-level capacity expansion, its project-level value might be positive (for example, if appropriate market structures to support storage exist). However, in that case further exploration of policies to support storage deployment based on its system-wide value would serve no purpose.

¹⁵ Additional types of social costs, such as health impacts related to specific types of pollutants, can also be considered in the analysis.

Phase 4: Simulate storage operation and stacking of revenues

Phase 4 of the framework analyses the actual operation of a storage project, assuming the project is a price-taker under the system-marginal prices obtained from simulations in Phase 3. In this phase, the revenue that the storage project receives is maximised by combining the various services the project can provide. In reality, very large electricity storage participating in energy markets has the potential to affect prices; thus, the results of Phase 4 represent a marginal project beyond the scenario in Phase 3 used to extract system-marginal prices.

This phase of the ESVF therefore assesses the revenue streams that electricity storage can bring to a project owner under specific market settings. A wide range of project-level benefits and costs of electricity storage depend on the market and regulatory environment surrounding the system of interest. Again, for this type of exercise dispatch simulation software (i.e. production cost software) is used for the analysis. However, the objective of the analysis is different from the previous step. Instead of **minimising** total system costs, the model rather **maximises** profits of a specific electricity storage project within the overall optimal storage portfolio resulting from Phase 3, under the assumptions below.

While in the previous step the charging and dispatching of the electricity storage device was decided on the basis of the needs of the whole system, in this case the decisions of the project are based on its individual economic interest. While in vertically integrated environments the two objectives coincide, in liberalised power markets the results are likely to be different and the focus is on privately owned storage systems participating in wholesale energy (and ancillary services) markets.

The model in this phase ignores the physical infrastructure of the remaining system, focusing solely on the storage project. In simplified terms, the model assumes that the remaining system's behaviour is unchanged, as the individual project is not able to influence key system variables. Examples of such variables are a) market prices of electricity, b) prices for provision of different types of grid services, c) the shape of net demand, d) reliability indicators, and e) dispatch of all other generators, including VRE. Such an approach (or model) is called a price-taker model. Re-dispatching the full system to realise the maximum benefit of the storage unit alone is challenging, as different pools of assets use different profit-maximisation algorithms.¹⁶

The choice of different long-term future scenarios affects project-level profits. This is because when electricity storage exists in a power system, it contributes to reducing the gap between peak and valley prices (because electricity storage time shifts low-cost electricity towards peak periods). The more storage that is integrated, the larger the smoothing effect on prices,¹⁷ which affects profitability when participating into electricity markets (Drury, Denholm, and Sioshansi, 2011; Nikolakakis and Fthenakis, 2018). Similarly, the system-level price of reserve provision depends on reserve requirements and on the capacity available to provide reserves, which again depends on the available storage portfolio. The system price of reserves drops as the level of storage increases.¹⁸

Using the inputs from the no new storage case (Step II above) provides insight into the value of storage during the early stages of storage deployment. Results represent the viability of a project under the assumption the situation continues for long period of time (i.e. there will be neither large-scale deployment of storage nor other significant changes to the physical structure of the system). Thus, if further storage is deployed, the longer-term economic viability of the project is uncertain, as in reality revenues could decrease (for example if VRE deployment stalled). The assumption is that if the amount of storage identified in the earlier stages of the framework is the actual amount that is expected to be deployed, the results of this phase will be reasonably accurate.

The model used to simulate project-level revenues needs to incorporate a number of typical services offered by storage in electricity markets. Examples include the following:

Energy arbitrage: This involves making a profit from charging the device when electricity prices are low and selling it when electricity prices are high. Depending on its technical characteristics a storage device can participate in either day-ahead or intraday markets, or both. Such bulk energy services are usually provided by electricity storage that has both large capacity and slow discharge time (such as pumped hydro and CAES), reducing the gap between peak and valley prices (because electricity storage time-shifts low-cost electricity towards peak periods). To simulate benefits from electricity arbitrage, a time series of system-wide electricity prices is needed representing operation of the generation mix identified from the previous step, Phase 3. When the price-taker model assumes perfect foresight of electricity prices, there is a risk of overestimating the value of energy arbitrage.

¹⁶ This is because the objective function of the optimisation needs to be the maximisation of storage profits subject to technical constraints (i.e. balancing supply and demand, start-up time constraints, ramping constraints etc.). If the whole system was participating in the production cost simulations with the above objective, all system assets would be dispatched with a goal of maximising the benefits to the storage project, not the benefits to the system. However, this is not representative of real-world operations.

¹⁷ This is one of the main reasons that energy arbitrage alone is not a viable long-term revenue stream for energy storage. As the storage capacity increases, the potential for profiting from arbitrage decreases.

¹⁸ The required level of reserves also depends on the uncertainty in the system introduced by VRE sources such as solar and wind power. The higher the solar and wind deployment, the larger the operating reserve requirement, which contributes to increased need for reserves.

Modern algorithms allow the uncertainty of electricity prices to be accounted for and can be used for improved results (Krishnamurthy et al., 2018; Salles et al., 2017).

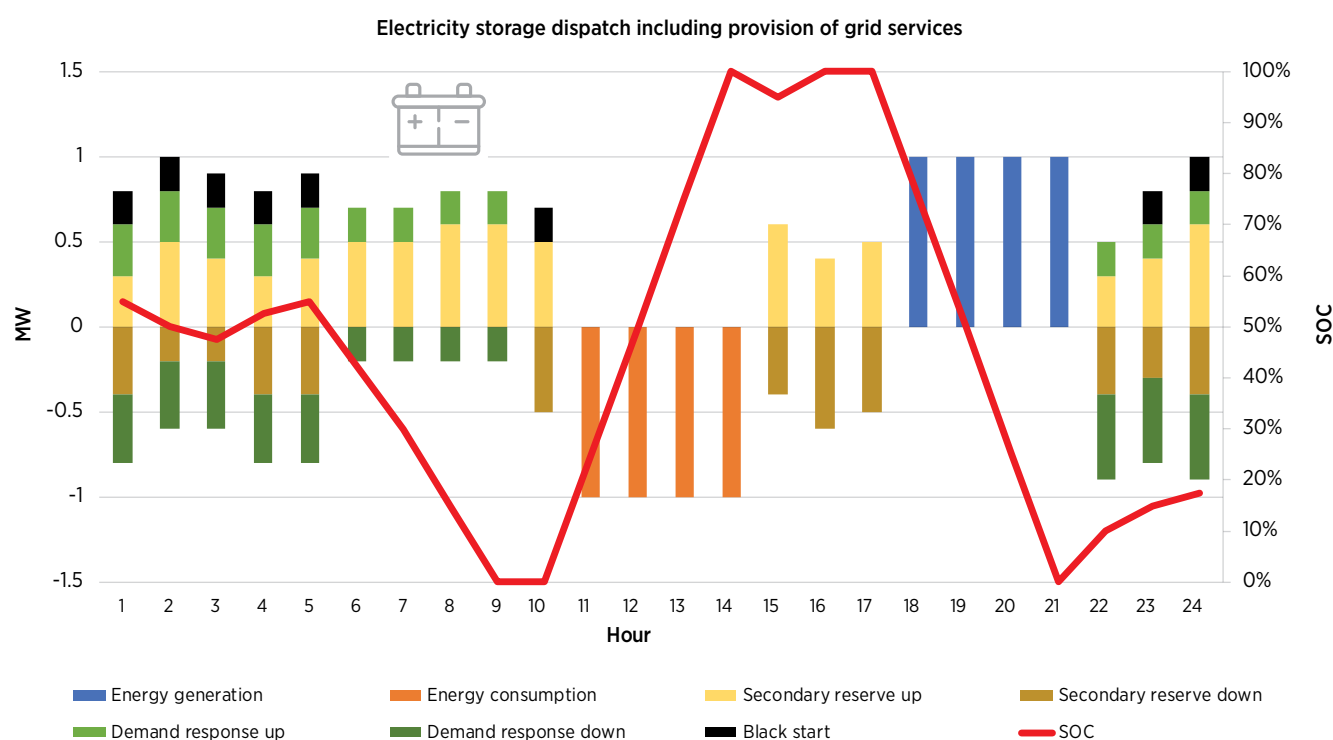
Finally, when not coupled with VRE, electricity storage charges up with electricity from various other types of generators. However, in a system with high proportion of VRE, electricity prices will be low during hours with high VRE penetration and essentially storage will mostly be contributing to smoothing out the net load. At low VRE levels (and potentially at higher VRE levels as well), electricity storage providing energy arbitrage could be contributing to increasing the capacity factor of cheap coal power plants and their energy share in the mix, as their lack of flexibility is compensated by storage flexibility.

Provision of ancillary services: These comprise a set of operational services whose primary role is to ensure reliable operation of the grid under both a) normal conditions and b) contingencies. The terminology, types and role of ancillary services vary around the world. For example, discussion around ancillary services in the United States and Europe can be found in NREL (2013) and Holttinen et al. (2012) respectively.¹⁹ Payment for ancillary services can be based on capacity procured, electricity produced or both depending on the case. Payments for various services need to be input in the model.²⁰

Ancillary services usually comprise frequency regulation, black start support and voltage control. Black start and voltage control cannot be explicitly modelled using dispatch tools and thus cannot be assessed using the ESVF. Electricity storage can simultaneously provide multiple services. For example, storage providing both energy arbitrage and operational reserves can potentially withhold some of the capacity that could be used for arbitrage if the payment is high enough. However, simulating actual utilisation of storage in ancillary services markets can be challenging.

Utilising the system-marginal prices from Phase 3, the various services a storage project can provide can be optimised to maximise the revenue the project receives. As a result of the optimisation, the hour-to-hour (or intra-hour) dispatch of the electricity storage project and stacking of its various revenue streams can be visualised. Figure 7 shows the type of output from storage service stacking that can be expected from Phase 4. In this illustration, the entire capacity of a 6 megawatt-hour (MWh) electricity storage facility is used to shift VRE from hours 11–14 to hours 18–21.

Figure 7: Illustrative output from Phase 4



Note: SOC = state of charge.

¹⁹ This report uses terminology most relevant to European countries.

²⁰ For example, payment for providing ancillary services in Ireland can be found in: www.eirgridgroup.com/site-files/library/EirGrid/Ancillary-Services-Statement-of-Payments-and-Charges-2017-2018.pdf.

Phase 5: Assess the viability of storage projects: System Value vs Monetisable Revenues

The system-wide benefits of storage can only be realised if the storage project is deemed viable, meaning that there are enough revenue streams to reward project developers/owners for their investment. Unfortunately, some system benefits cannot be monetised or are not directly attainable by the project owner. Therefore, in many cases there is insufficient incentive for a prospective project developer to go ahead.

Comparing calculated system benefits from Phase 3 with the project owner's potential revenue streams for the set of services optimised in Phase 4 can be instructive. The electricity prices derived from the simulations in Phase 3 are used here to calculate the revenue streams for an electricity storage project.

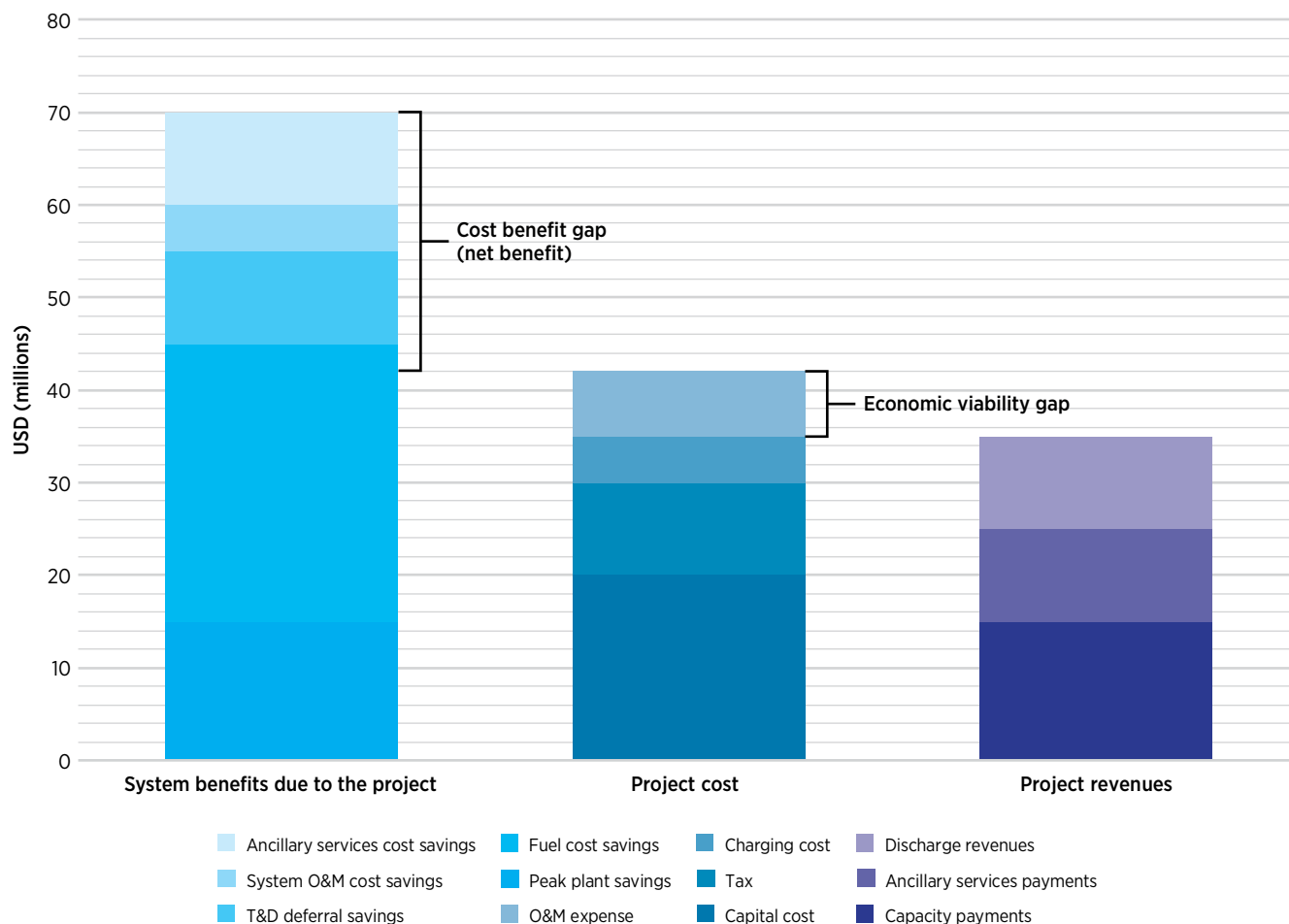
The outputs represent the revenue streams available to a storage project owner alongside the associated system benefits. If the revenue streams available to the project owner are not enough to cover the cost of the storage project, but the system benefits attributed to this project outweigh the cost, stakeholders can use the results of this analysis to identify the most beneficial uses and to consider methods to incentivise their deployment.

The output of this final phase is a project-level cost and benefit analysis. Cost refers to the cost of building and operating a storage project under a specified case. Benefits refer to both system level (non-monetisable) and project level (monetisable) benefits.

The benefits are categorised as monetisable or non-monetisable. If the total benefits exceed costs, but monetised benefits are less than costs, it means that the project developers do not have enough economic incentive to build this project even if it has a benefit-to-cost ratio of greater than one. In this case, policy intervention would be needed to enhance the overall social good.

Figure 8 shows an example of the outcome from a project feasibility model. In this particular example, although the system benefits outweigh the costs, the monetisable benefits 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 high storage capital costs or unfavourable market mechanisms.

Figure 8: Illustrative output from Phase 5



4 Recommendations

4.1 Recommendations for different storage stakeholders

A framework must be developed that both compensates storage providers for the value they can provide to the system and is in line with wider policy objectives. Various policy measures can be implemented to ensure that electricity storage projects are sufficiently compensated to be deployed, yet not overcompensated (RMI, 2015). Policy recommendations that may be relevant for regulators, vertically integrated utilities, the research community and electricity storage developers are listed below.

For electricity storage developers

As IRENA's latest costing report on storage suggests (IRENA, 2017a), by 2030 total installed costs for battery storage could fall by 50% to 60%. Electricity storage developers have a variety of market-specific business models available to make a viable case for their projects. An example of a business model for distributed storage is that of aggregators. As IRENA's "Innovation landscape brief on aggregators" (IRENA, 2019c) highlights, aggregators can operate a diverse pool of distributed energy resources, including storage, creating a sizeable capacity similar to that of a conventional generator. This allows them to participate in different markets and therefore monetise revenue streams otherwise not accessible to individual, small-scale storage projects. Collaboration, in particular with regulators and utilities, is vital to highlight the benefits that electricity storage can provide to the system and discuss which business models could help accelerate electricity storage deployment.

For vertically integrated utilities

Vertically integrated utilities may want to consider upgrading their planning tools and run open multi-stakeholder consultations to allow rate designers, planners and grid operators to work together to capture electricity storage's full range of capabilities. Other recommendations for utilities include having updated and expanded modelling of storage in integrated resource plans, updating procurement processes for the performance or services required, as opposed to technology-specific requirements (which might preclude storage), and exploring new ownership models for electricity storage (ESA, 2017).

Most power systems worldwide are based on a vertically integrated utility structure where capturing the full value of storage is potentially more straightforward, compared to a more complex deregulated environment where issues such as ownership structure of storage assets and the missing money issue are a major concern. In an environment where generation, storage and grid assets are owned by the same entity, such entities can capture the full value of storage for the system, provided this is accounted for correctly. This framework aims to support such valuation process, as well as providing insights for both vertically integrated and unbundled settings.

For regulators

A key recommendation for regulators is that of eliminating barriers to electricity storage participation in energy, capacity and ancillary services markets (for instance, see FERC, 2018). An example of barriers could be the reserve duration requirement, which could be too long for many storage systems, or the minimum capacity to participate in the ancillary services market, which could be too large for some storage systems. An option in this case would be to design a new product where storage could participate to provide its full value.

Another option is to explicitly include storage among the various technology options or to eliminate technology-based discrimination in ancillary services markets. An important feature of storage is its ability to stack revenues from providing multiple services; however, in some cases the regulatory framework does not allow it to do so (for instance, this has been addressed in California with Decision 18-01-003 in Rulemaking 15-03-011 [CPUC, 2018], which allows stacking of T&D reliability with generation services).

A further option for regulators is that of creating markets that are able to capture the full value of storage, such as the performance-based regulation implemented by the PJM for fast frequency response (IRENA, 2017b). For more information on fast frequency response and other examples of implementation of storage cases, please see Part 3 of this report. Another possible recommendation for regulators is that of requiring utilities and transmission/distribution system operators to use a least-cost and standardised methodology that compares electricity storage providing a full range of stacked services against incumbent technologies. This should apply across all planning processes – including distribution planning, transmission planning and resource planning.

The regulatory frameworks for storage exhibit fundamental differences depending on its classification as demand or generation and on which stakeholders are allowed to own storage assets.

For behind-the-meter storage, a careful review should be conducted of how to provide monetisable revenue streams to consumers that invest in storage, as lack of price signals often makes the case for behind-the-meter storage unviable (for more information see dedicated chapter in Part 3).

Regulatory innovation is essential to accommodate higher shares of VRE using storage. A particular example of this is in Japan, where as opposed to the transmission system operator procuring ancillary services directly, some utilities require larger PV projects to use battery storage to meet grid frequency requirements and thus control their feed-in of electricity. A clear example of this is the 38 megawatt (MW) Tomakomai solar PV project located on the northern Japanese island of Hokkaido.

The PV plant has a battery that was one of the world's largest at the time of its construction in 2017: a circa 20 MW/10 MWh lithium-ion battery. The sole purpose of the storage system is to meet the frequency requirements of the local energy utility, Hokkaido Electric Power Company (IRENA, 2019b).

For the research community

A key recommendation for the research community is to develop and validate appropriate tools and detailed methodologies to perform storage valuation as described in this report (Part 2 in particular). Objectives may include, for example, increasing the time resolution of tools (e.g. hourly to sub-hourly), ensuring that chronology is preserved, or capturing how storage value decreases with increasing amounts of storage. Moreover, of utmost importance is modelling future scenarios and potential technical and economic impacts to inform policy makers and regulators in their decision making.

4.2 Policies and regulations to support cost-effective storage deployment

There are two ways to improve the economic feasibility of storage projects: a) by compensating project developers using various policy incentives to make up for the economic viability gap, or b) by improving existing market mechanisms to increase the monetisable benefits available to storage in order to reduce the gap.

Policy incentives: Policy incentives to make up for the economic viability gap of electricity storage projects can be similar to those that have been used to support VRE deployment in its early stages of development. These include:

- **Feed-in-tariffs (FITs):** To encourage deployment of VRE projects, many governments pay a fixed price per kWh, irrespective of wholesale electricity market prices, for electricity generated from renewable resources. A FIT can also be a policy measure to incentivise deployment of storage for VRE integration. The electricity generated from a combined VRE and storage asset is paid a fixed price, or the feed-in rate, reflective of the higher value to the system that a combined VRE plus storage project can provide compared to VRE only.
- **Feed-in-premiums (FIPs):** In this particular scheme, the electricity generated from a combined VRE and storage asset is sold on the electricity spot market, and the producers are offered a premium that is above the market price. The FIP can either be fixed (independent of the market price) or sliding (varying depending on the market price) and should be reflective of the value of the services provided in addition to the energy.
- **Capacity payments:** Periodic payments to the project owner for its contribution to system adequacy (for instance, by avoiding the need for investment in peaking plants) support project viability with a predictable revenue stream, especially when the wholesale energy and ancillary services prices are too volatile to make a storage project financially viable. For example, the California Public Utility Commission requires the utilities to procure capacities with a monthly payment under contract to ensure there are enough resources in the market for competitiveness and reliability purposes.²¹ However, depending on how capacity mechanisms are designed, they might be detrimental to storage projects by reducing price volatility and remuneration for flexibility from such assets.
- **Grants:** Grants are used to reduce the capital costs of the storage asset. This policy measure can be specified as a percentage of the capital costs. Rebates such as the Self-Generation Incentive Program (SGIP) in California, focusing on behind-the-meter storage, are a widely applied form of grant.
- **Peak reduction incentives:** To reduce demand peaks, some jurisdictions have demand response programmes to incentivise load reduction. Storage can be used to reduce load during system peak hours. The project owner is only paid the peak reduction revenue when the storage asset happens to reduce load during the system peak hours. In the case where a consumer tariff is linked to the maximum demand, storage can provide significant savings by reducing the capacity charge component of the tariff.
- **Investment tax credits (ITCs):** If most of the electricity used to charge the storage asset comes from VRE, the project can be made eligible for ITCs. Many ITC structures have a VRE-charging threshold above which the project can capture ITCs. For example, if the charging threshold is 80%, the project is eligible for ITCs only when more than 80% of the charging electricity comes from VRE. An ITC is defined as a percentage of total CAPEX if the storage asset charges solely from VRE. If less than 100%, but more than the threshold percentage, of electricity comes from VRE, the ITC is pro-rated based on the percentage of charging electricity. The ITC benefits are usually distributed over a number of years. This is a US-specific example of current regulatory options where storage support is linked directly to renewables. It might not be ideal to replicate it as-is elsewhere, as it might lead to over-incentivising storage.

21 See the latest rules on such contracts, called resource adequacy contracts, from CPUC, "Proposed Decision Refining the Resource Adequacy Program", 21 November 2018, <http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=243570563>.

- **Accelerated depreciation:** This policy measure enables depreciation of the storage asset at an accelerated rate to receive tax benefits. Many such policy constructions have a defined depreciation rate, or other standard rates such as double-depreciation or a modified accelerated cost recovery system (MACRS).

Market mechanisms: Existing electricity market settings have typically been designed to balance supply and demand, separating generators and load as distinct entities. In electricity storage, the roles of generating and consuming electricity overlap, making it difficult for storage to fit into existing market frameworks, unless it is treated differently at different points in time, specifically as a load while charging and a generator while discharging. Consequently, regulatory and market barriers to the full utilisation of electricity storage remain in many markets (Gissey, Dodds, and Radcliffe, 2018; Sandia National Laboratories, 2013).

Because the participation rules and market mechanisms differ from region to region, solutions that fit every local situation are hard to devise. However, modifying rules to allow electricity storage to fully participate in the electricity markets is critical to realising the system benefits that electricity storage can provide, and to ensuring sufficient monetisable revenues for storage projects to be viable.

In a landmark ruling in February 2018, the Federal Energy Regulatory Commission (FERC) in the United States required the regional grid system operators under its jurisdiction to revise their tariffs to establish mechanisms that recognise the physical and operational characteristics of electricity storage, to facilitate its participation in the markets. FERC Order 841 (FERC, 2018) sets requirements for such participation models.

To comply, the storage resource must:

- Be allowed to provide all capacity, energy and ancillary services that it is technically capable of providing.
- Be able to set the wholesale market clearing price.
- Have appropriate physical and operational characteristics.
- Be able to manage its own state of charge (UtilityDive, 2018).

Grid operators under FERC jurisdiction are currently finalising their proposed responses to comply with the FERC order, with implementation of the revised market rules scheduled for December 2019. In the European Union, the role of electricity storage in facilitating VRE integration was officially recognised in the Electricity

Market Design Directive where new rules were formally adopted in May 2019. Improvements in the directive aim to reduce barriers to energy storage; it mandates non-discriminatory and competitive procurement of balancing services and fair rules in relation to network access and charging (European Commission, 2019; Norton Rose Fulbright, 2019).

5. Conclusions

Why storage valuation matters

Electricity storage technologies are a critical enabler for integrating large shares of VRE into power systems, facilitating the acceleration of the energy transition through rapid and scalable deployment and efficient provision of ancillary services, with the ability to be located virtually anywhere in the grid. VRE generators are increasingly co-deploying storage to maximise the profitability of their generation assets (e.g. increasing capture price, accessing ancillary services revenues). Similarly, customers are installing behind-the-meter storage to reduce their electricity supply cost, often in conjunction with rooftop PV; such assets, if aggregated, can provide valuable additional services to the grid.

Electricity storage deployment is currently taking place in all parts of the grid and by a multiplicity of stakeholders. The ESVF presented in this report is intended to support regulators and other stakeholders in the use of modelling tools to assess the system value of electricity storage in a power system and assess the monetisable revenues of storage projects under an existing regulatory framework. The results can be used to support policy makers in understanding whether there is a “missing money issue” to be addressed and in developing appropriate frameworks to ensure the efficient deployment of storage to facilitate the energy transition.

The overview of the ESVF in Part 1 is intended to provide power system decision makers, regulators and grid operators with an understanding of how to value and, where appropriate, support the deployment of electricity storage in the grid system.

Part 2 describes specific details of the ESVF methodology, including a methodology to carry out the analysis: the type of modelling tools necessary, information flow between phases, proposed model structure, step-by-step instructions on how the benefits are calculated, and expected inputs and outputs of the phases are discussed in detail.

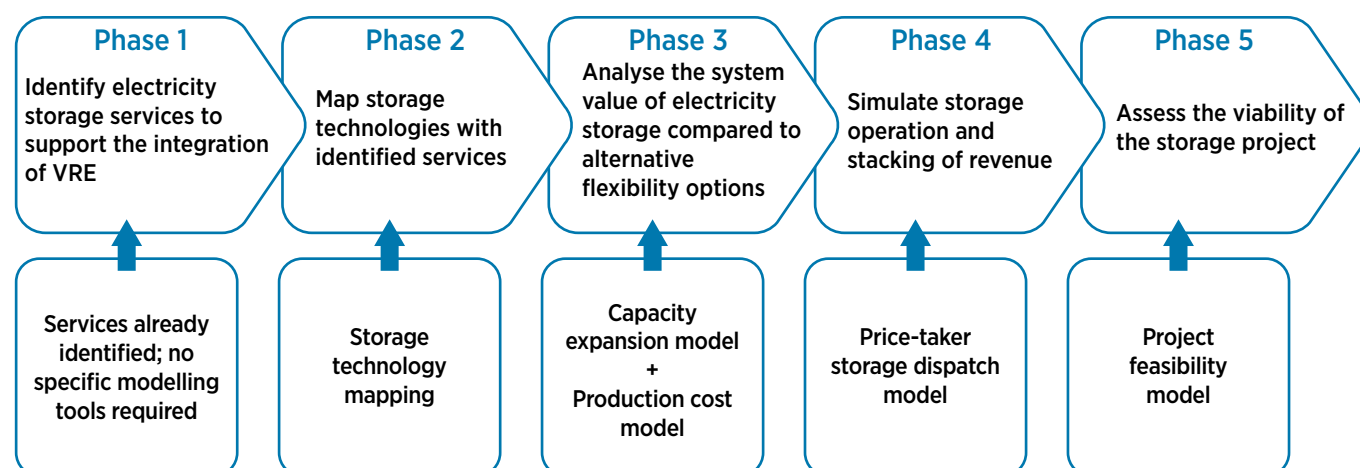
Part 2 is intended for a technical audience to examine the logic of the framework’s methodology and then adopt it for electricity storage project cost-benefit analysis using the necessary power system modelling tools.



Part 2:

Using power system models to assess value and viability

Figure 9: ESVF phases and the types of models used



1. Introduction

Part 2 of this report aims to support analysts apply the Electricity Storage Valuation Framework (ESVF). The ESVF has a number of phases that require expert use of advanced optimisation models. The following sections explain which types of models are needed and how interested stakeholders and analysts can use them to complete the analysis. To implement the ESVF, several different types of models must be used to carry out the analysis (Figure 9).

Phase 1 of the framework identifies the services that electricity storage can provide to integrate more variable renewable energy (VRE) into the power system. No specific modelling tools are required for this phase.

Phase 2 requires inputs from storage technology experts in determining the suitability of various technologies for different countries. No specific types of models are recommended; instead, the information can be collated in a spreadsheet to show the attributes and scoring criteria applied to each technology to reflect their suitability in providing the services.

In **Phase 3** a capacity expansion model is utilised to optimise the capacity of storage and any alternative technologies. The phase then requires multiple iterations of production cost model runs to evaluate and optimise the benefits of having storage in the electric power system.

In **Phase 4** a price-taker storage dispatch tool is used to optimise the storage operation to realise maximum possible multiple stacked benefits. As an output from the dispatch tool, the hourly (or sub-hourly if data are available) operation of the storage should be accessible for further analysis. This tool is useful mostly for project developers in liberalised power systems with an electricity market; in other situations the stacked benefits of storage can be drawn from the production cost model in Phase 3.

In **Phase 5** a project feasibility model should be used to study the costs and monetisable revenues for storage project owners. This model should help identify the cases where the benefits to the system of a specific storage project exceed costs, but monetisable revenues for the projects are not enough to cover the costs, preventing projects from being deployed.

In these cost-effective cases, a variety of regulatory options should be considered to ensure that cost-effective projects are deployed. Policy makers and regulators can then use the results of this analysis to identify the economic viability gap and devise appropriate incentives so that projects that are seen to be worthwhile at the system level are sufficiently compensated at the project level to move forward. This is particularly relevant in the case of a liberalised market.

In liberalised markets storage can be owned by a variety of entities, in conjunction with generation, consumption or as a stand-alone market participant. This scenario requires assessing the value that such storage can provide to the system and adjusting the regulatory framework to ensure that such projects will be realised. A variety of mechanisms exists to achieve this; the main objective of this phase of the framework is to verify that the different models of storage ownership can access enough monetisable revenues to ensure their deployment, not exceeding the value they provide to the system or the amount of storage above which its marginal cost exceeds its marginal value.

This aspect is particularly relevant as for some services the value of storage decreases rapidly, with an oversupply of storage reducing monetisable revenue streams for all storage projects and the risk of making all projects become less profitable until at one point they become unviable. In the case of vertically integrated environments, utilities are sometimes willing to accommodate independent project developers and thus a similar approach can be used to ensure project developers are sufficiently remunerated.

The information flow in Phases 3–5 of the ESVF (those that require modelling), as well as that between phases, is presented in Figure 10.

Figure 10: Information flow between modelling-based phases of the framework (Phases 3–5)

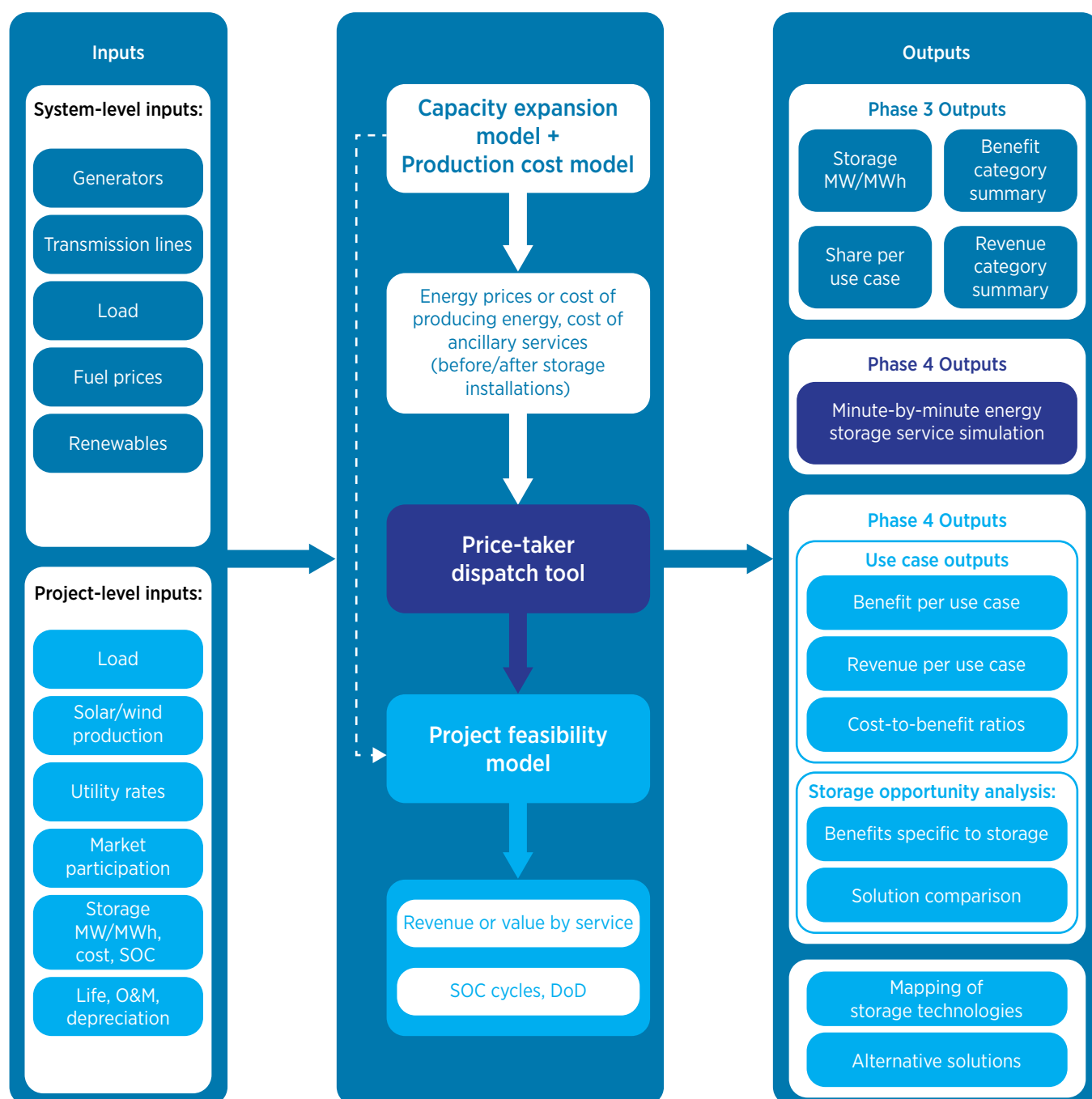


Figure 11 shows an example of the outcome from a project feasibility model in Phase 5. In this example, although the system-wide benefits outweigh the storage costs, the monetisable benefits are less than the costs, making the project economically infeasible for the project developer/owner. The difference between the cost and the monetisable benefit, or the economic viability gap, if greater than zero, could be due to high storage capital costs or unfavourable market mechanisms. In this specific example, compensating storage for offsetting the need for peaking plant capital investment would be sufficient to make storage projects viable, something that can be, for example, achieved with a capacity market in which storage is allowed to participate.

2. Methodology

Phase 1: Identify electricity storage services supporting the integration of VRE

As mentioned previously, all the services that electricity storage provides in supporting the integration of VRE are identified in Phase 1. Figure 12 shows the variety of services that have been identified by past analyses, with the red boxes representing those services that are quantifiable within this framework. For this phase, no specific modelling tools are required.

Figure 11: Economic viability gap identified in the project feasibility analysis

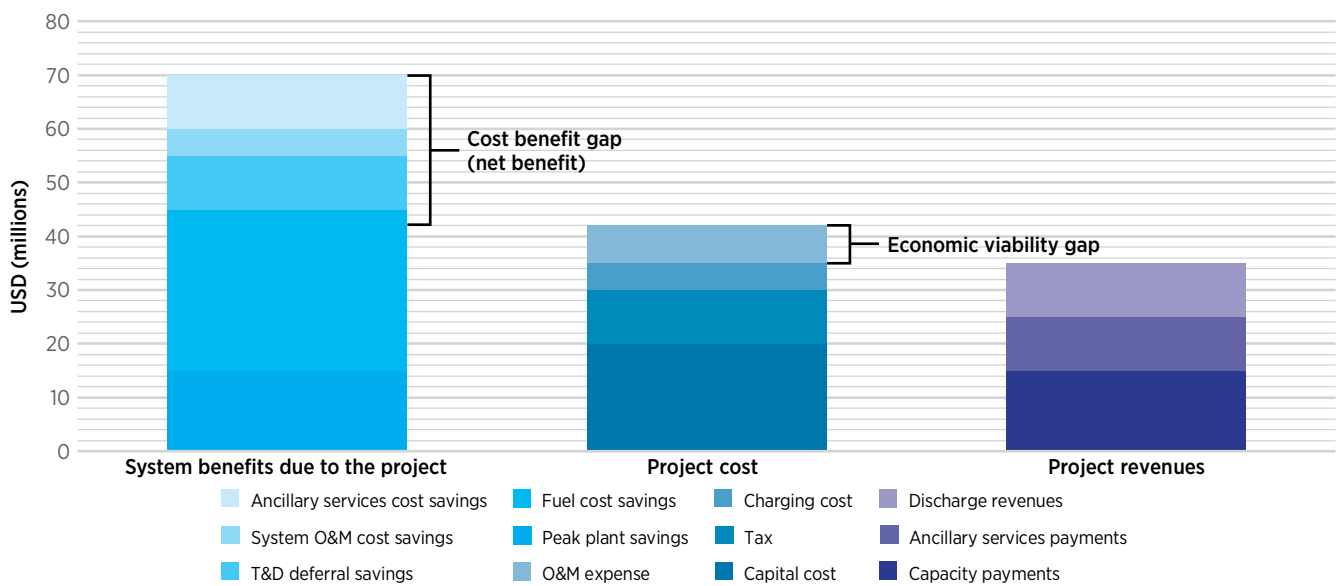
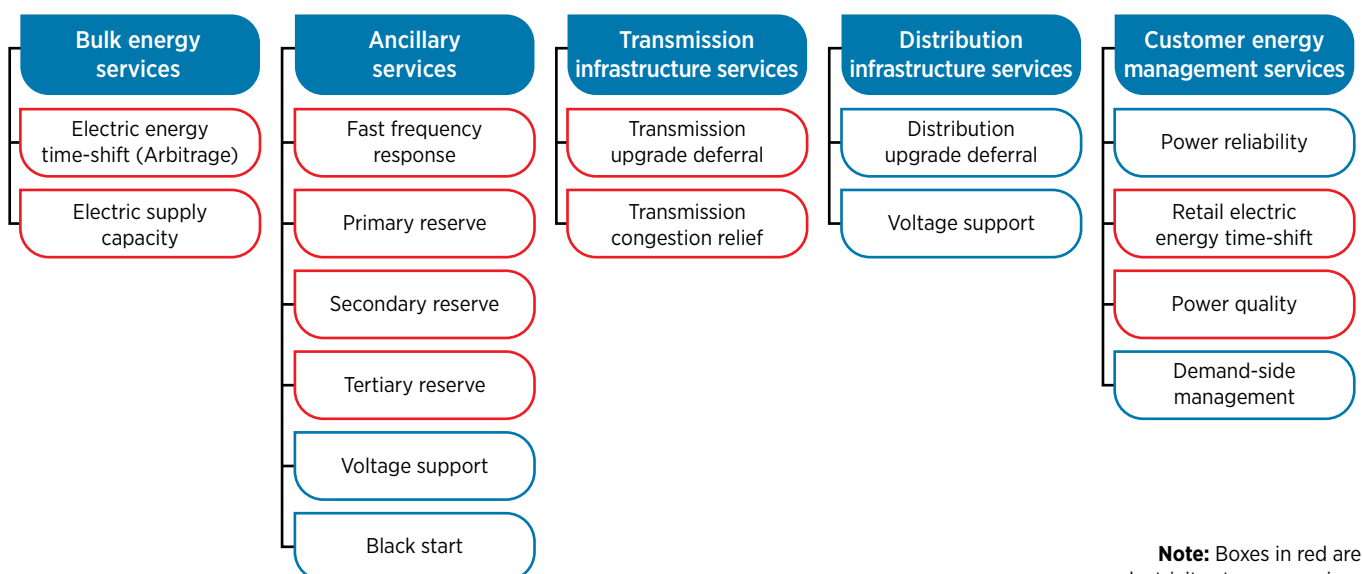


Figure 12: Quantifiable electricity storage services



Note: Boxes in red are electricity storage services that are quantifiable within this framework.

Phase 2: Storage technology mapping

In Phase 2 of the ESVF, an overview of the suitability of different storage technologies for various applications must be established. The method described below ranks storage technologies based on various technical and commercial parameters for each service. A list of suggested storage technologies for consideration can be found in Table 3.

Table 3: Storage technologies for consideration

Mechanical storage	Pumped hydro storage CAES Flywheels
Lead-acid batteries	VRLA
High-temperature batteries	NaNiCl NaS
Flow batteries	Vanadium flow ZnBr hybrid flow
Lithium-ion batteries	NMC NCA LFP LTO

Notes: CAES = compressed air energy storage; LFP = lithium ferrophosphate; LTO = lithium titanate; NaNiCl = sodium nickel chloride; NaS = sodium sulphur; NCA = lithium nickel cobalt aluminium; NMC = lithium nickel manganese cobalt; VRLA = valve-regulated lead acid; ZnBr = zinc bromine.

Methodology

Step 1: Assigning competitive scores to technologies

The suggested storage technologies are listed based on various technical and commercial parameters (see Figure 13):

- Technical parameters: AC-to-AC efficiency, rate of charge, rate of discharge, energy density, power density, minimum C-rate,²² maximum C-rate, depth of discharge (DoD), maximum operating temperature, and safety as indicated by thermal stability (where applicable).
- Commercial parameters: storage capital expenditure (CAPEX), power conversion system capital expenditure (PCS CAPEX), years required for project development and construction, operating costs, operating life, and maturity of technology.

Sample default values for these attributes can be found in IRENA's costing analysis (IRENA, 2017a), but the values can also be adjusted based on country-specific or project-specific information. Sample values are presented in Figure 13.

²² C-rate is a measure of the ratio between the power rating and the energy rating of a storage device. A 1C rate means that at full power, the storage will be depleted in 1 hour. A 2C rate = 30 minutes for the device to be completely discharged, while C/2 = 2 hours for a full discharge, and so on.



Photograph: Shutterstock

Figure 13: Sample default values for storage technology mapping

Parameters	VRLA	Pumped Hydro	CAES	Flywheels	NMC	NCA	LFP	LTO	NaS	NaNiCl ₂ (Zebra)	ZBB	VRB
Technical												
Efficiency (AC-to-AC) (%)	81%	80%	64%	85%	92%	92%	86%	96%	81%	85%	72%	72%
C-Rate min	C/10	C/20	C/10	1C	C/4	C/4	C/4	C/4	C/8	C/8	C/8	C/8
C-Rate max	2C	C/6	C/4	4C	2C	1C	2C	10C	C/6	C/6	C/4	C/4
DOD (%)	50%	90%	40%	85%	90%	90%	90%	95%	100%	100%	100%	100%
Max. Operating Temperature (°C)	50	NA	NA	NA	55	55	65	65	NA	NA	50	50
Safety (Thermal Stability)	High	NA	NA	NA	Medium	Low	High	High	Medium	Medium	Medium	High
Commercial												
Storage Capex (\$/kWh)	226	21	48	2 656	339	284	466	880	436	323	696	268
Development & Construction (Years)	0.25	5	3	1	0.5	0.5	0.5	0.5	0.5	0.5	1	1
Operating Cost (\$/kWh)	3	2	1	80	8	8	8	6	8	8	15	11
Energy Density (Wh/L)	75	1	4	110	470	410	410	410	220	215	45	42.5
Power Density (W/L)	355	NA	NA	7 500	5 050	5 050	5 050	5 050	140	210	13	2
Life (full equivalent cycles)	500	20 000	20 000	>100 000	3 500	1 500	3 500	10 000	5 000	3 500	4 000	10 000
Maturity of Technology	M	M	C	EC	C	C	C	EC	C	D	EC	EC

Notes: kg = kilogram; kW = kilowatt; kWh = kilowatt hour; L = litre; VRB = vanadium redox battery; W = watt; Wh = watt hour; ZBB = zinc bromine battery.

Sources: Customized Energy Solutions (CES) market expertise for “Development and Construction”, data sheets of key manufacturers for “C-Rate”, “Max. Operating Temperature” and “Life” and IRENA (2017a) for the rest.

A sample exercise to assign competitive values follows:

Based on the values of technical and commercial parameters, competitive scores of 1 to 5 can be assigned to each parameter, with 5 representing the best score and 1 representing the worst (see Table 4). For some parameters, such as efficiency, DoD, operating costs, and life, relative merits are not difficult to recognise. Thus, a 5 can be awarded to the technology that is most efficient or has the deepest DoD cycle, lowest operating costs, or longest life.

For other parameters:

- Scores for C-Rate are based on the maximum output power possible for a technology. For example, a 10 MWh LFP battery can output power at 20 MW (=2C) with an appropriate power conversion system, whereas a 10 MWh CAES will most likely be designed for a discharge time of 4 hours or more which corresponds to C/4. The C-Rate score for LFP is therefore higher.
- Scores for initial capital costs, length of development and construction, space required, and maturity of technology can be found in past analyses (IRENA, 2015a; Lazard, 2017; E3, 2017; HECO, 2016). These factors may change from country to country and the scores should therefore be adjusted as appropriate.

Table 4: Sample look-up table for competitive score

Score	5	4	3	2	1
Technical					
Efficiency	> 95%	86.25–95%	77.5–86.25%	68.75–77.5%	< 60%
C-rate	1C and above	C/2–1C	C/4–C/2	C/8–C/4	C/8 and lower
DoD	> 95%	86.25–95%	77.5–86.25%	68.75–77.5%	< 60%
Commercial					
Initial capital cost	< USD100/kWh	USD100–325/kWh	USD325–550/kWh	USD550–775 / kWh	> USD1 000/kWh
Development and construction	6 months and less	6–16.5 months	16.5–27 months	27–37.5 months	4 years and longer
Operating cost	Lowest of all technologies				Highest of all technologies
Space required	> 500 Wh/kg	382.5–500 Wh/kg	265–382.5 Wh/kg	147.5–30 Wh/kg	< 30 Wh/kg
Life	Longest of all technologies				Shortest of all technologies
Maturity of technology	Mature	Commercialisation	Early Commercialisation	Demonstration	Prototype

Based on the scoring criteria in Table 4, a sample of scores for various technologies is shown in Figure 14.

Figure 14: Example of competitive scores for storage technologies

Parameters	VRLA	Pumped Hydro	CAES	Flywheels	NMC	NCA	LFP	LTO	NaS	NaNiCl2 (Zebra)	ZBB	VRB
Technical												
Efficiency	● 3.4	● 3.2	○ 1	● 3.7	● 4.6	● 4.6	● 3.9	● 5	● 3.2	● 3.7	● 2.1	● 2.1
C-Rate	● 5	● 2	● 2	● 5	● 5	● 4	● 5	● 5	● 2	● 2	● 2	● 2
DoD	○ 1	● 3	● 3	● 4	● 4	● 3	● 4	● 4	● 3	● 3	● 5	● 5
Commercial												
Initial Capital Cost	● 4.7	● 4.4	● 4.3	● 2	● 3.8	● 4.1	● 3.4	● 2	● 3.5	● 3.9	● 2.3	● 3.2
Development & Construction	● 5	○ 1	● 2.1	● 4.7	● 5	● 5	● 5	● 4.7	● 4.7	● 4.7	● 4.2	● 4.2
Operating Cost	● 4.9	● 4.9	● 5	○ 1	● 4.7	● 4.7	● 4.7	● 4.7	● 4.6	● 4.6	● 4	● 4
Space Required	○ 1.5	○ 1	○ 1	● 2.3	● 3.3	● 3.3	● 3	● 3.3	○ 1.3	○ 1.2	○ 1.2	○ 1
Life	○ 1.1	● 5	● 5	● 5	○ 1.3	○ 1	○ 1.4	● 3.6	● 2.1	○ 1.6	● 3.6	● 4.4
Maturity of Technology	● 5	● 5	● 4	● 3	● 4	● 4	● 4	● 3	● 4	● 2	○ 1	● 2

Step 2: Assigning weightings to parameters for applications

Next, a set of weightings is applied to each parameter under different applications. Depending on the application, some parameters are more important than others. Figure 15 shows an illustrative example of how the table of weightings for each parameter could look. As mentioned, these weightings are only illustrative and are not for unquestioned use in storage valuation exercises. For each valuation exercise the weightings should be adjusted based on the specific projects, technologies, regulatory framework and market settings.

Weightings must be adjusted for each project, technology, regulatory framework and market setting

Figure 15: Example of illustrative parameter weightings for different applications

	Renewable Shifting	Renewable Smoothing	Flex Ramping	Ancillary Services	T&D Deferral	Reactive Power Management	BTM Power Management
Technical							
Efficiency	10%	10%	10%	10%	5%	10%	10%
C-Rate	0%	15%	0%	15%	0%	0%	5%
Usable SOC	10%	10%	10%	10%	10%	10%	10%
Commercial							
Initial capital cost	40%	30%	40%	30%	30%	30%	30%
Development and construction	5%	5%	5%	5%	20%	5%	5%
Operating cost	10%	10%	10%	10%	10%	10%	10%
Space required	5%	0%	5%	0%	10%	15%	15%
Life	10%	10%	10%	10%	5%	10%	5%
Maturity of technology	10%	10%	10%	10%	10%	10%	10%
	100%	100%	100%	100%	100%	100%	100%

Notes: The total weighting in each column should be 100%; T&D = transmission and distribution.



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Step 3: Applying suitability matrix

The competitive scores for different technologies and the weightings for the applications together provide an overall picture of how suitable each technology is for each application. However, the combination of scores and weightings of parameters are often insufficient because they could vary depending on the specific case. To avoid the complexity of providing competitive scores and weightings for each technology and each case, a suitability matrix is used. The suitability matrix provides

an opportunity to adjust the weighted score further. For example, lead acid batteries are cost-competitive, but are less suitable for high C-rate uses such as VRE smoothing or primary/secondary reserve. While technically a lead acid battery system can be designed to provide VRE smoothing or primary/secondary reserves, its usable SOC is a limitation unless the cost increases significantly. To capture such cases, the suitability matrix is applied on top of the results from the competitive scores and parameters weightings for each application. A sample of default values in a suitability matrix is shown in Figure 16.

Figure 16: Example of suitability matrix for different applications

Parameters	VRLA	Pumped Hydro	CAES	Flywheels	NMC	NCA	LFP	LTO	NaS	NaNiCl2 (Zebra)	ZBB	VRB
Renewable Shifting	☯ 0.8	● 1.0	● 1.0	☯ 0.3	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0
Renewable Smoothing	☯ 0.8	☯ 0.3	☯ 0.3	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0	☯ 0.3	☯ 0.3	☯ 0.3	☯ 0.3
Flex Ramping	☯ 0.8	● 1.0	● 1.0	☯ 0.5	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0
Ancillary Services	☯ 0.5	☯ 0.3	☯ 0.3	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0	☯ 0.3	☯ 0.3	☯ 0.3	☯ 0.3
T&D Deferral	● 1.0	● 1.0	● 1.0	☯ 0.3	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0
Reactive Power Management	● 1.0	☯ 0.3	☯ 0.3	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0	☯ 0.3	☯ 0.3	☯ 0.3	☯ 0.3
BTM Power Management	● 1.0	○ 0.0	○ 0.0	☯ 0.3	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0	● 1.0

Note: BTM = behind-the-meter.



Photograph: Shutterstock

Application ranking

The weighted average competitive scores for each technology and for each case are calculated by multiplying the competitive scores, weighting and suitability matrices in Steps 1 to 3. Technologies are then ranked based on their weighted average score for a given case, with 1 being the most suitable for a specific application, 10 the least suitable. Rankings can be shown as a heat map of how suitable each technology is for each case (see Figure 17 and Figure 18). A green colour denotes most suitable technologies while red shows less suitable ones. The top-ranked technologies are used in the subsequent project feasibility analysis phase of the ESVF. Please note that values in this section are purely indicative, and they have to be adjusted case by case when performing the analysis depending on the system, the technologies and other specific conditions.

Phase 3: System value analysis

The next phase of the ESVF is to conduct a system-level analysis to calculate the total economic benefit of building storage assets in a given power system. The baseline is built by selecting a starting system, either being an existing system or a future plan. This will be the reference point for assessing the potential for storage deployment to reduce total system cost. Electricity demand is an input in this type of analysis together with others (such as fuel and capital investment costs) needed to assess the total cost of the plan. If the analysis is intended to estimate the value of storage at the present time, the current demand is given. Alternatively, the same approach can be followed to assess the long-term benefits of storage by supplying some future level of demand (either assumed or deduced from a top-down or bottom-up model, fed with relevant data and assumptions), effectively developing a future long-term scenario. The analysis will then calculate the optimal amount to be built based on a combination of capacity expansion least-cost optimisation and production cost modelling.

Figure 17: Example of weighted scores

Parameters	VRLA	Pumped Hydro	CAES	Flywheels	NMC	NCA	LFP	LTO	NaS	NaNiCl2 (Zebra)	ZBB	VRB
Renewable Shifting	2.81	3.97	3.68	0.71	3.80	3.79	3.56	3.23	3.39	3.35	2.76	3.29
Renewable Smoothing	2.96	0.95	0.87	3.26	4.00	3.81	3.82	3.62	0.82	0.80	0.69	0.81
Flex Ramping	2.81	3.97	3.68	1.41	3.80	3.79	3.56	3.23	3.39	3.35	2.76	3.29
Ancillary Services	1.98	0.95	0.87	3.26	4.00	3.81	3.82	3.62	0.82	0.80	0.69	0.81
T&D Deferral	3.88	3.32	3.31	0.75	4.04	4.01	3.86	3.47	3.55	3.46	2.94	3.33
Reactive Power Management	3.43	0.91	0.84	2.85	3.75	3.71	3.52	3.36	0.79	0.77	0.66	0.77
BTM Power Management	3.62	-	-	0.71	3.93	3.86	3.70	3.43	3.17	3.10	2.57	2.95

Figure 18: Example of application ranking

Parameters	VRLA	Pumped Hydro	CAES	Flywheels	NMC	NCA	LFP	LTO	NaS	NaNiCl2 (Zebra)	ZBB	VRB
Renewable Shifting	10	1	4	12	2	3	5	9	6	7	11	8
Renewable Smoothing	6	7	8	5	1	3	2	4	9	11	12	10
Flex Ramping	10	1	4	12	2	3	5	9	6	7	11	8
Ancillary Services	6	7	8	5	1	3	2	4	9	11	12	10
T&D Deferral	3	9	10	12	1	2	4	6	5	7	11	8
Reactive Power Management	4	7	8	6	1	2	3	5	9	10	12	11
BTM Power Management	4	11	11	10	1	2	3	5	6	7	9	8

Note: 1 = best; 10 = worst.

The system-level analysis as proposed in the ESVF can be used to study standalone electricity storage systems. In standalone operation, a storage unit could be (for example) a utility-owned asset (in regulated environments) or operate independently under a specific market setting. In the first case, storage offers system services to the whole utility and storage CAPEX costs should be compared to utility-wide benefits from storage. If there is a net benefit for the utility, then investing in storage makes economic sense for the utility and there is no need to apply Phase 4 of the framework.

In the case of an independent power provider, Phase 4 of the framework can be used to assess if an independent operator could make a profit operating storage independently. Similarly, in a market environment, the system-wide benefits of storage need to be compared with the potential revenue streams a market can offer. A comparison of the two cases is not enough to conclude whether investing in storage makes sense. The financial viability of a project depends on project valuation analysis that compares CAPEX and operating expenditure (OPEX) costs and revenues.

A further comparison with system-wide benefits gives additional insights, particularly on whether policy interventions are needed to better support storage deployment.

The ESVF can be used to estimate the system-level benefits of behind-the-meter storage by aggregating the storage capacity within the distribution network to the level represented by the capacity expansion and production cost models (i.e. zonal, nodal level). The system-wide benefits of storage at the distribution level are similar to those of storage deployed on the high-voltage network, although the range of services that can be provided is wider at the distribution level.

Capacity expansion optimisation

Capacity expansion optimisation is a method used to assess the optimal combination of investments in the power sector. Depending on the tool capabilities, such investments could include renewables, energy efficiency, demand response, electricity storage and peaking power plants, as well as sector-coupling options to reduce total system investment and operating costs. The analysis should start from the existing system and take into account the cost of additional investments in electricity storage and flexibility alternatives. The outputs are additional investment in technologies a) where electricity storage is not available, and b) where electricity storage is available, as well as the amount of storage capacity needed. Table 5 shows types of user inputs, variables and constraints for incorporation into the objective function to be minimised.

Table 5: Parameters used in optimising the capacity for alternative technologies

	User input	Variables	Constraints
Peaking generators (open-cycle gas turbines and diesel generators)	- Capital cost (USD/kW) - VOM (USD/MWh) - FOM (USD/kW year) - Fuel cost (USD/mBtu) - Heat rate (Btu/kWh)	- New capacity - Generation	Operational range
Energy efficiency	- Capital cost (USD/kW) (cost increases with deployment) - Maximum investment - Energy savings per investment	- Investment - Energy savings	- Maximum investment - Energy savings proportional to investment
Demand-side flexibility	Capacity cost (cost increases with deployment)	- Equipment investment - Demand response exercise (up and down)	Maximum capacity
VRE	- Capital costs (USD/kW) - Capacity factor profile	- Capacity - Generation	- Resources - Maximum capacity
Electricity storage	- Capacity costs (USD/kW) - Capacity costs (USD/kWh)	- Power and energy capacities - Inventory	- Inventory - Maximum capacity (power and energy)

Notes: FOM = fixed operational and maintenance VOM = variable operational and maintenance.

Production cost modelling

Using the results from the capacity expansion optimisation (optimised capacities of various technologies), the next step is to perform production cost modelling to minimise the total cost of operation with and without electricity storage. Production cost models can co-optimize the actual dispatch and allocation of operational reserves of a given generation fleet at a time step representative of real-time operations (from 1 hour to seconds) considering various real-world constraints.

Such constraints include transmission constraints, unit constraints (as in the case of ramping constraints, operational range and minimum up and down times), policy constraints (as in the case of a carbon cap or carbon pricing) and system constraints (as in the case of a non-synchronous penetration limit). The cases to be optimised are based on the results of the capacity expansion assessment (with and without electricity storage).

Production cost modelling in the system-level assessment of electricity storage is used for the following two reasons:

- To obtain a more accurate assessment of OPEX. Capacity expansion models assess OPEX at a time step much longer than 1 hour.²³ As a result, capacity expansion software returns only an approximation of production costs. After the capacity mix has been optimised, production cost models are used to verify and improve the assessment of OPEX.
- To assess operational benefits of electricity storage. Capacity expansion models are not capable of assessing the operational benefits of flexible assets in the system due to their limited temporal granularity. Capturing the actual operational benefits of electricity storage is challenging due to its fast response times compared to other technologies. The finer the temporal resolution of a capacity expansion model, the higher the accuracy of the results. Capacity expansion models can be used only to give an approximation of the capacity (power and energy) of electricity storage needed. The power capacity resulting from the capacity expansion optimisation is used as an input in a subsequent step where production cost modelling is used to improve the assessment of electricity storage needed in the system through an iterative process intended to find the optimal duration of electricity storage.

The process should start with short-duration storage (0.5 hours or less), and gradually increase the duration to find the least-cost solution. While there might be one optimal amount of electricity

storage capacity, in practice the storage portfolio will comprise an array of various durations from 0.5 to 8+ hours. To provide firm capacity, which is a large piece of the value of storage, longer-duration storage will be needed. For some markets this is 4 hours – others provide capacity value for shorter durations and some require longer. This might require another type of analysis that considers the saturation effects of storage for peak load reduction (Stenlik et al., 2018)

The steps to calculate the benefits to the power system are as follows (see also Figure 19):

Step 1:

Capacity expansion optimisation: electricity storage and flexibility alternatives, such as energy efficiency, demand response, renewable energy and conventional power plants, are used to meet load growth of the system. Alternatives can also include sector-coupling options such as electric vehicles, electric boilers, heat pumps and hydrogen production from renewables.

The analysis should optimise the capacity of each resource with the objective of minimising the sum of capital and operational costs for the system (total system cost). This step calls for an appropriate tool, capable of optimising storage size (both power and energy). Available tools vary in terms of granularity, technical focus and practicality, and tool selection should be made considering the characteristics of the power system to be studied and data availability. For example, if the value of storage needs to be assessed at the zonal/nodal level then available tools should be capable of modelling transmission.

In addition, a study focusing on electricity storage should use capacity expansion optimisation software capable of simulating time steps as short as possible. IRENA has recently developed and made available to the public a tool capable of sizing and dispatching electricity storage, mostly applicable for high-level analysis. The IRENA FlexTool can be used for system-level analysis (both capacity expansion and production cost simulations) (IRENA, 2018b). The capacity expansion optimisation is performed twice: first, without electricity storage to set the baseline (or the “no new storage”) case; and then with electricity storage added to set the “with new storage” case. The differences in the capacity mix of the two cases are used to assess CAPEX-related benefits.

Step 2:

Run a production cost model based on the baseline system to estimate operational costs.

²³ Many capacity expansion software tools use load duration curves as inputs, which are broken down in a number of blocks of varying duration.

Step 3:

Run another production cost model on the “with new storage” case, with a power rating from capacity expansion optimisation in Step 1 and an energy rating the same as the power rating (C1).

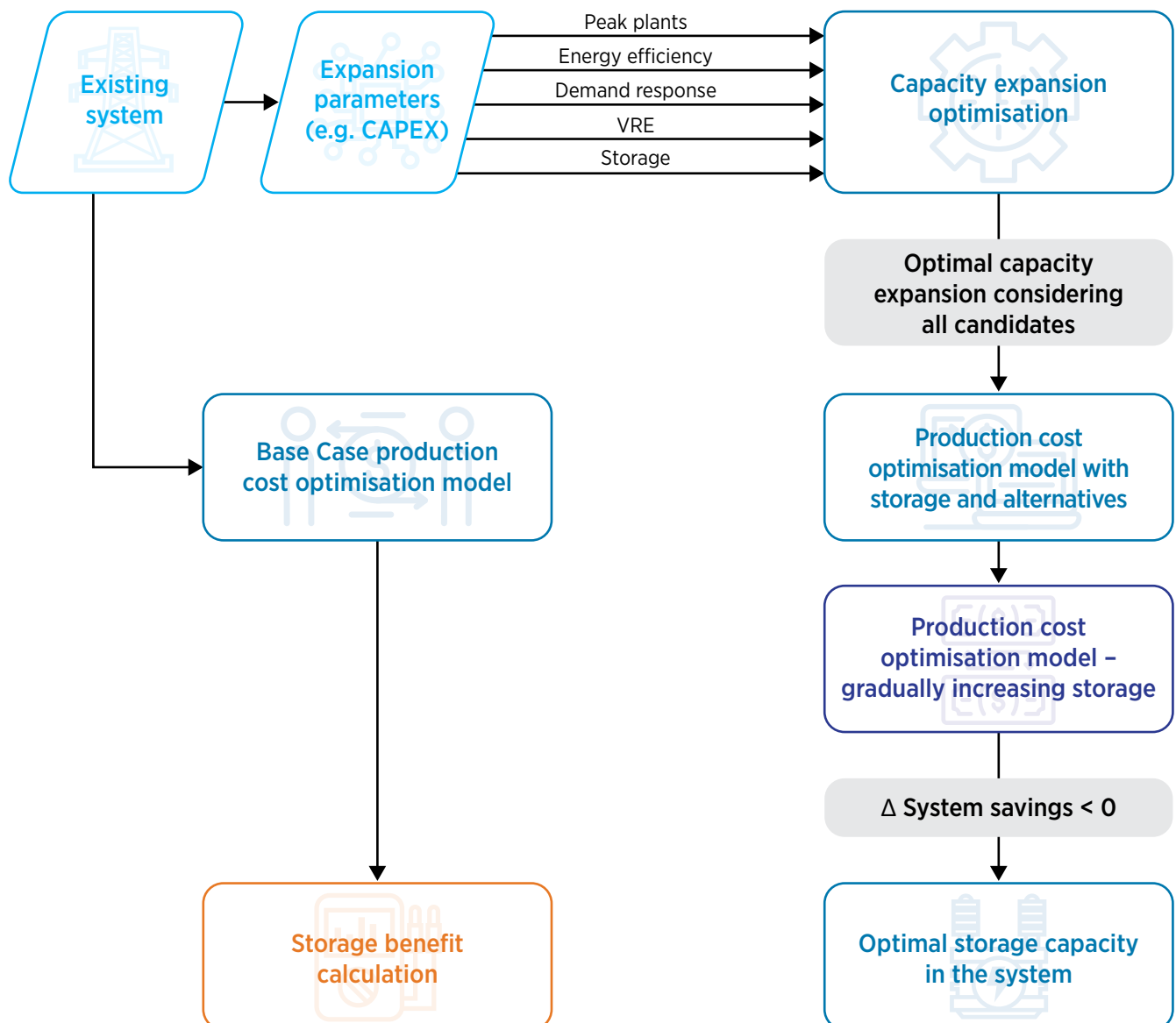
Step 4:

Gradually increase the energy capacity (duration) of electricity storage; run the production cost model with each increase to find out the optimal electricity storage duration that minimises the production cost. Stop increasing storage capacity when the cost of adding storage exceeds production cost reduction (when total system cost would start increasing by adding more storage capacity).

Step 5:

Compare the production costs between Steps 2 and 4 and analyse the benefits of storage including potential benefits from ancillary services cost reduction. Such benefits result from a) more efficient dispatch of units, since conventional generators will have more available capacity after storage takes on ancillary services, and b) deferring the need for conventional capacity (this can be quantified through capacity expansion optimisation assuming the formulation of the problem considers the need to withhold capacity for ancillary services).

Figure 19: Calculation steps in system value analysis



Electricity storage benefits for the power system

As described in the previous sections, a comparison of the “no new storage” and “with new storage” cases can be made to assess CAPEX- and OPEX-related benefits of electricity storage on the power system.

In this section, the benefit categories are defined with qualitative discussion of the cost components. Power system optimisation models allocate the OPEX- and CAPEX-related costs to new investments and power system operation. However, some OPEX and CAPEX elements might be difficult to separate and quantify, as explained below.

CAPEX-related costs are usually straightforward to both quantify and separate. For example, when running a capacity-expansion exercise, the transmission capacity needed to supply either current or future demand can be identified. Running the exercise with electricity storage might defer the need for some of this transmission capacity. The CAPEX related to this deferred transmission capacity is the related benefit. Similarly, electricity storage can offer a variety of ancillary services that would otherwise be provided by conventional generators. Deployment of electricity storage increases the capacity levels available from conventional generators, thus potentially deferring the need for new capacity. The formulation of the capacity expansion models should allow these aspects of CAPEX-related benefits of ancillary service provision to be captured (Li et al., 2017). Similarly, electricity storage could defer the need for peak capacity by providing load following and shifting the timing of electricity production.

However, quantifying distribution-related CAPEX benefits is not straightforward. The difficulty relates to the practical difficulties of representing a power system at the distribution level using capacity expansion software. Similarly, OPEX-related benefits of electricity storage are hard to estimate at the distribution level, and in most cases storage capacity is aggregated for modelling purposes to the level that can be captured by the model/software. To accurately assess CAPEX- or OPEX-related benefits at the distribution level, a different approach from the one used in the ESVF is needed, potentially using network models (Zobaa et al., 2018; Joshi, Pindoriya and Srivastava, 2018; Li et al., 2018).

With regard to estimating OPEX-related savings, a straightforward comparison of production cost modelling results, between the “baseline” and “with new storage” cases, can be used to assess total fuel cost-related savings.

The total amount of fuel cost savings due to electricity storage depends on the combined effect of the various functions of electricity storage. They relate to a more economic electricity dispatch of generating assets due to electricity storage contributing energy and ancillary services. More specifically, fuel cost-related savings can result from:

- Reducing the cycling of thermal generators, which leads to a) a lower number of start-ups and b) reduced hours of operation at partial loading (which negatively affects thermal efficiency).
- Replacing expensive thermal generators during peak hours.
- Replacing flexible thermal generators for provision of load following.
- Replacing thermal capacity for provision of ancillary services. This leads to a more efficient system-wide dispatch through a) increased availability of thermal capacity for energy services, and b) dispatch of electricity storage for frequency regulation.
- Supporting penetration of renewable energy at the expense of thermal generation.
- Reduced grid operational expenditure through transmission congestion relief.
- Additional OPEX-related cost savings are:
 - Reduced VOM costs for thermal generators.
 - Reduced CO₂ emissions (where carbon pricing is present there are direct benefits).
 - Cost savings due to reduction in VRE curtailment levels.

Even though estimation of total fuel-related (and non-fuel related) OPEX savings is straightforward, further separation into individual components is either challenging or even practically impossible through the use of optimisation modelling. This is mainly due to the complex and dynamic interaction of system elements – any effort to disaggregate costs would require the introduction of additional scenarios to obtain only an estimate of additivities.

Table 6: Storage benefits categorised as quantifiable and non-quantifiable

Quantifiable benefits	Benefits more difficult to quantify
OPEX-related benefits - Total fuel cost savings due to a more economic dispatch resulting from a combination of factors (i.e. storage replacing fossil-fuelled generation and provision of ancillary services) - Start-up cost savings (note that start-up cost savings are part of fuel saving costs) - VRE curtailment savings - VOM savings - Reduced CO2 emissions (where carbon pricing is present there are direct benefits).	OPEX-related benefits - While estimating total fuel savings is straightforward, breaking them down into separate quantifiable categories is difficult. The following elements of total fuel cost savings cannot be easily separated: - Replacing costly energy generation during peak hours - Supporting penetration of renewables at the expense of fossil-fuelled generation - Replacing fast-responding thermal capacity used for provision of load following and other ancillary services - Reduced grid operational expenditure through transmission congestion relief - Reducing cycling of thermal generators. - Provision of ancillary services - Actual dispatch of primary and secondary reserves - Voltage support - Black-start savings.
CAPEX-related benefits - Deferring the need for peaking capacity - Transmission capacity deferral savings - In some cases, deferring the need for other flexibility alternatives (e.g. heat pumps or electric boilers).	CAPEX-related benefits Distribution network capacity deferral savings

Table 6 above categorises electricity storage benefits as directly quantifiable and difficult to quantify. Benefits in the first column can be quantified with optimisation models, while those in the second column are more difficult to capture with optimisation models, as they tend to be very location-specific, market-specific or requiring other modelling methodologies. More detailed discussion about individual storage benefits follows.

A. Reduced cost of producing electricity

The reduced cost of producing electricity is manifested in the production cost models as reduced fuel costs, reduced VOM costs, and reduced start-up and shutdown costs.

Electricity storage changes the cost of producing electricity in several ways:

- By fulfilling demand during peak hours with low-cost electricity stored during off-peak hours.** In a grid system with increasing penetration of VRE, the grid operator can store electricity during times of abundant VRE generation – usually

periods with low electricity prices – to be used later. This displaces more expensive peak generation resources such as oil, reducing prices during peak hours, and avoids potential price spikes related to scarcity events. In a vertically integrated system structure where a cleared market price is not calculated explicitly, the cost of supplying electricity is lowered for the same reasons.

Figure 20 illustrates how electricity storage reduces peak load and therefore the cost of electricity during peak hours. In the top panel, load in a scenario without storage is shown as the shaded grey area, whereas load in a scenario with storage is shown in orange. By charging during off-peak hours and discharging during peak hours, as shown in the bottom panel, storage effectively flattens and reduces the peak load. If the storage device is directly connected to VRE, it performs a similar function.

In both cases electricity storage facilitates penetration of VRE in the electricity mix by a) shifting VRE generation towards peak hours and b) reducing VRE curtailment. At high VRE shares, storage supports a higher share of VRE by reducing curtailment and creating a case for viable investment in additional VRE.

Figure 20: Load profile over 24 hours with and without storage (top panel) and storage charge and discharge over 24 hours (bottom panel)

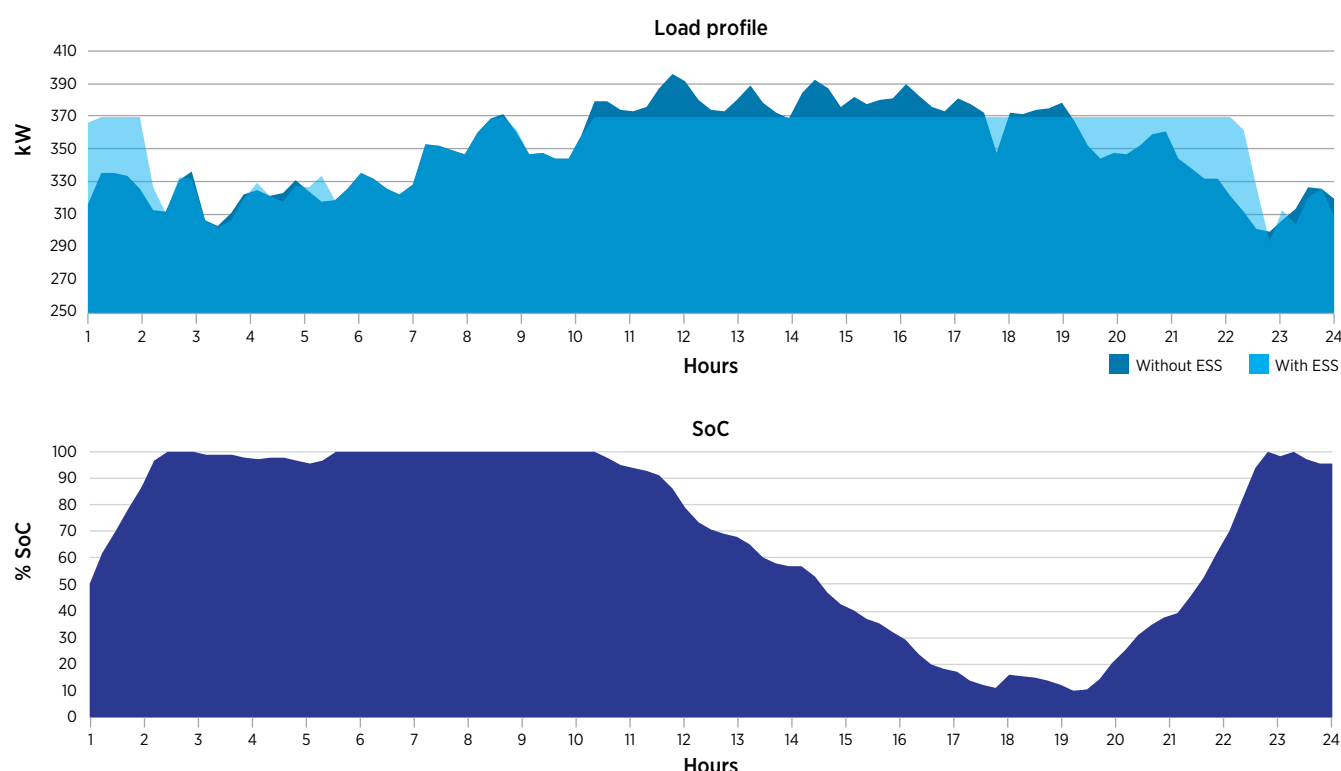
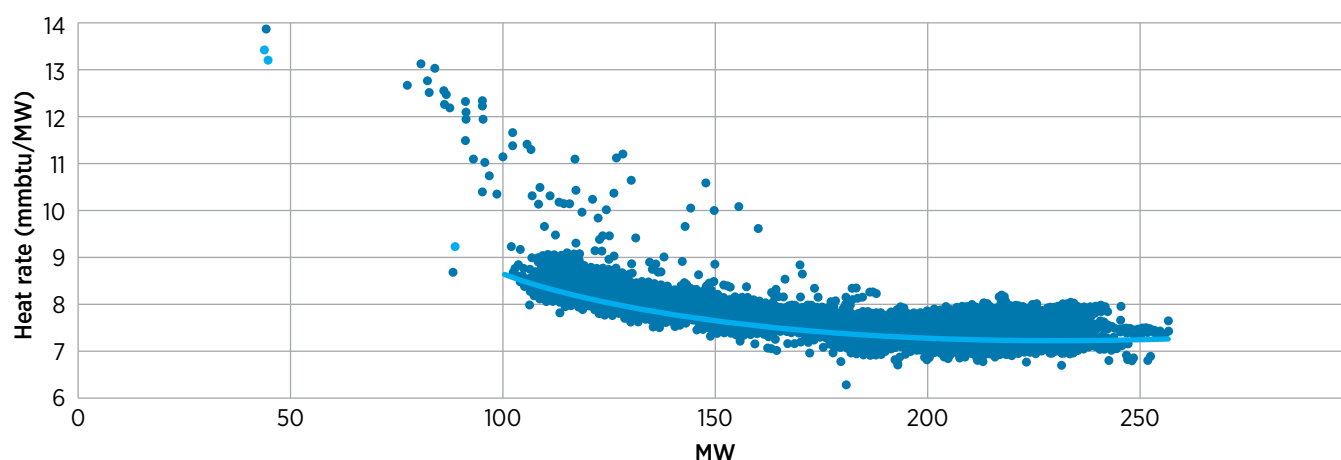


Figure 21: Heat rate curve of a thermal generator



Source: NREL (2012).

- **By utilising storage to follow load variations and allow thermal generators to improve overall operational efficiency.** Higher proportions of VRE on the system cause conventional thermal generators to cycle more frequently to balance fluctuations in net load caused by solar and wind variability and uncertainty (IRENA, 2018a).

As shown in Figure 21, a thermal generator's heat rate²⁴ increases (or its efficiency decreases) when its output deviates from its optimal operational point.

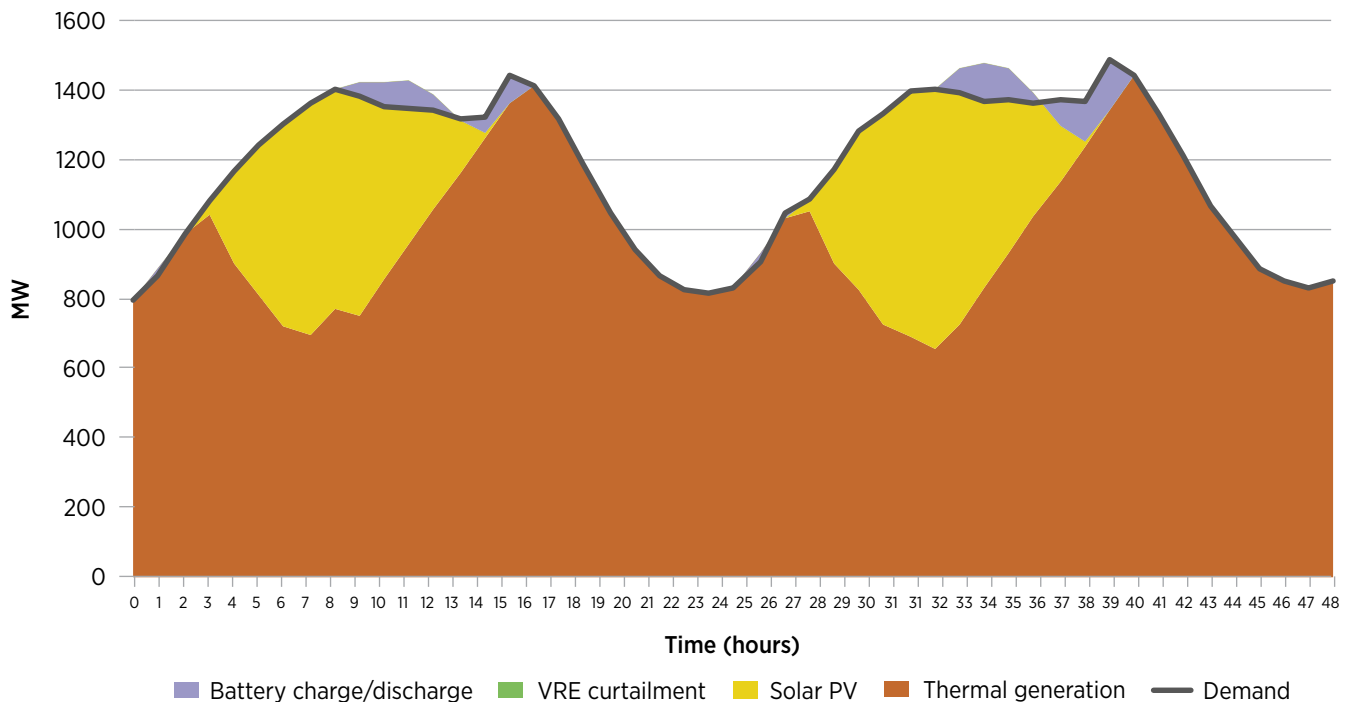
If a generator follows the load by increasing or decreasing its output, it moves away from its optimal operational point, resulting in inefficient use of fuel. Instead, if electricity storage is used to meet the changes in net load, the fossil fuel generators can operate at constant and optimal output, decreasing their fuel costs and their wear and tear cost related to cycling. In a vertically integrated market structure, such operation effectively reduces the cost of serving the load; in an unbundled market, the electricity storage alleviates the load-following burden on some thermal resources while also potentially replacing some marginal units.

²⁴ The efficiency of thermal generators is expressed as the heat rate, or the amount of thermal energy input over the amount of electricity output, usually in Btu/kWh. The lower the heat rate, the more efficient the thermal generator.

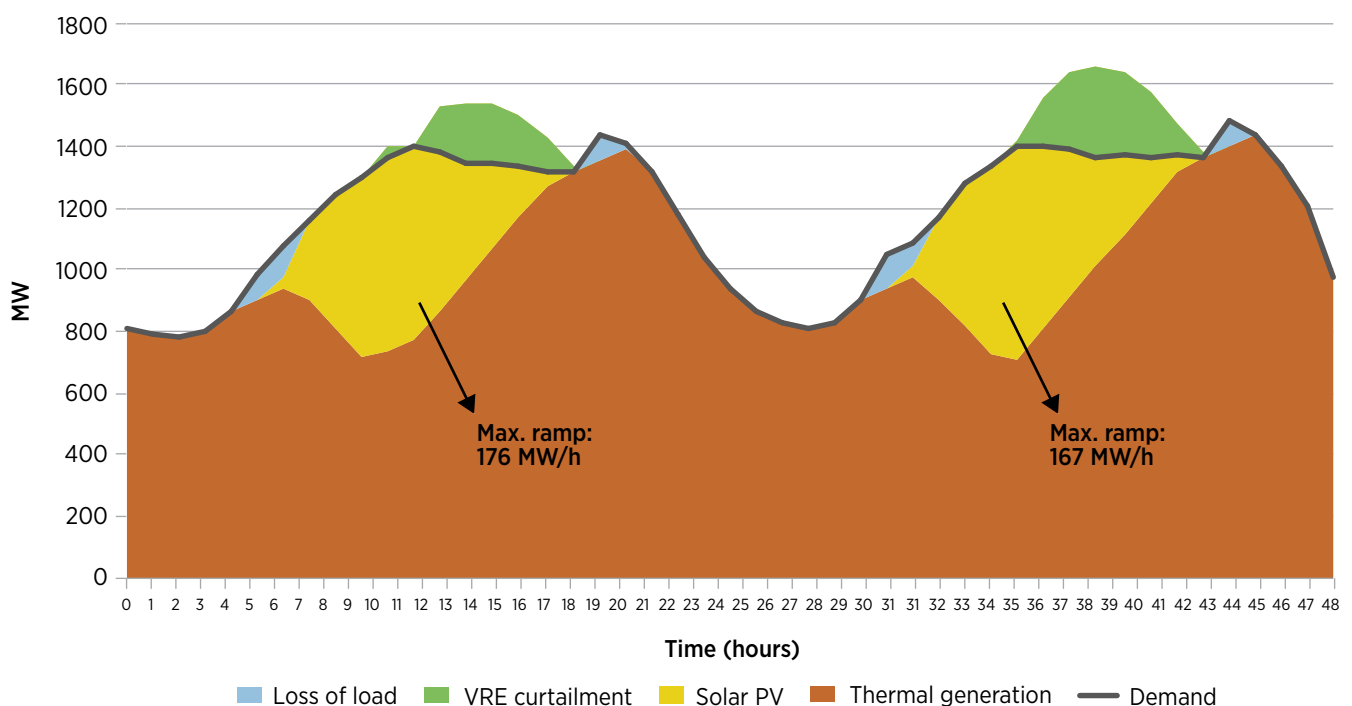
Fuel savings due to increased thermal efficiency are more significant in small systems operating mostly with diesel capacity. The example in Figure 22 shows how electricity storage can perform rapid ramping, avoiding solar curtailment and loss of load due to insufficient ramping capability of thermal generators.

Electricity storage can perform rapid ramping, avoiding solar curtailment and loss of load

Figure 22: Demand, ramping curves and VRE curtailment without storage (top panel) and with storage (bottom panel)

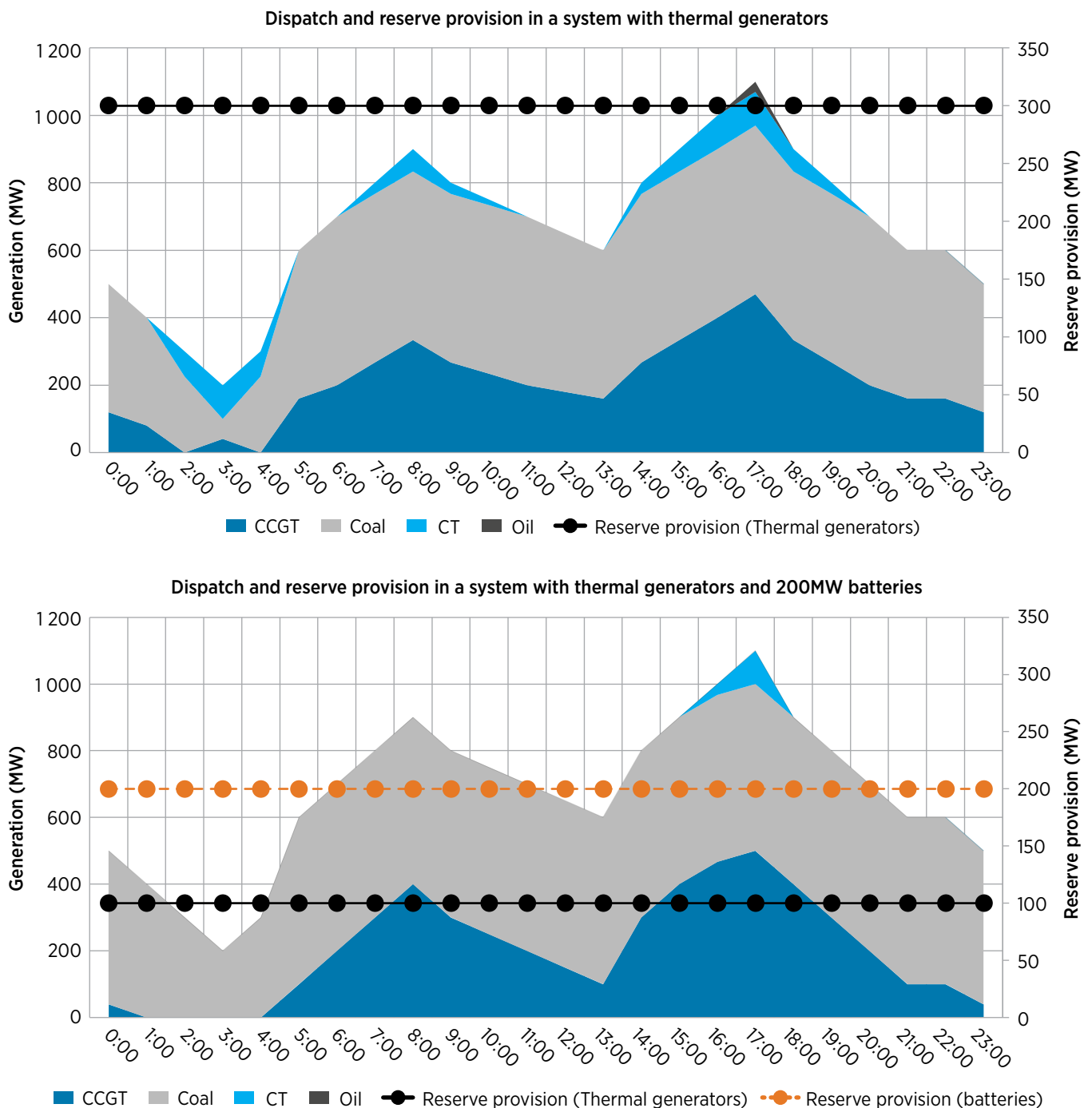


Thermal unit ramp:
102 MW/h



- **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 ESFV.
- **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 quality²⁶ 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-optimize 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.

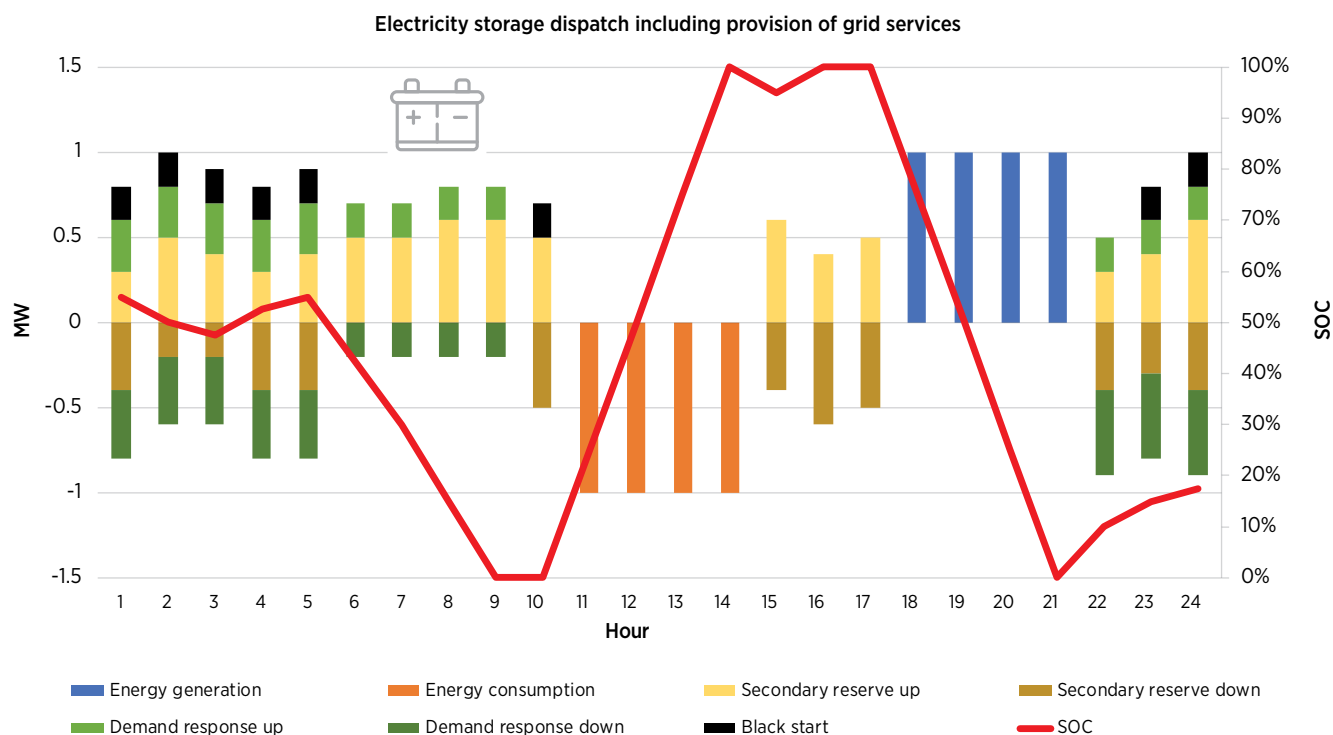
²⁷ VRE can also provide reactive power. However, doing so reduces active power, therefore affecting the economics of VRE power plants.

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)

Benefit categories	Benefit bucket	Energy storage size			
		2C	1C	0.5C	0.25C
		72	344	645	1670
		USD /MW	USD /MW	USD /MW	USD /MW
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):

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

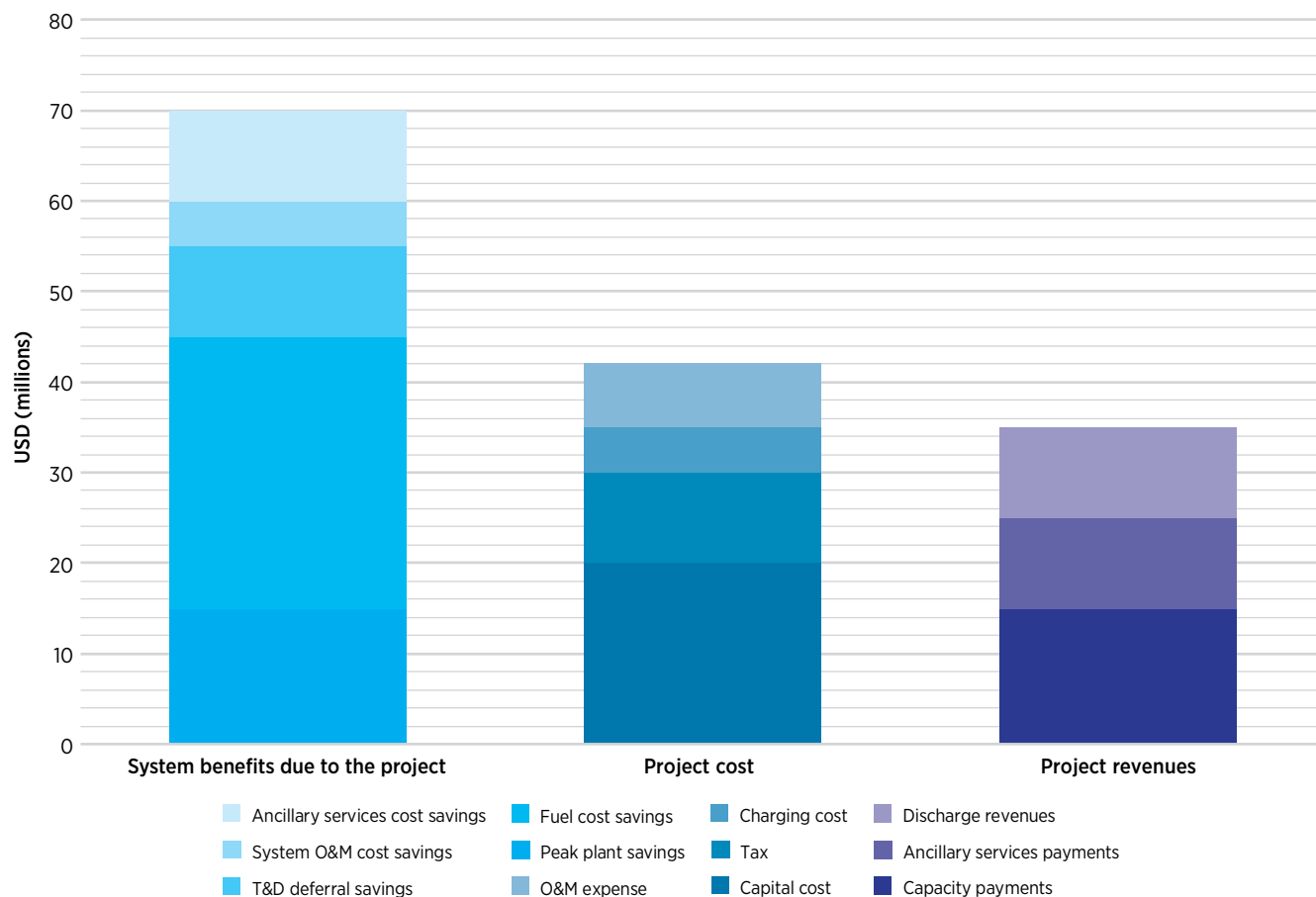
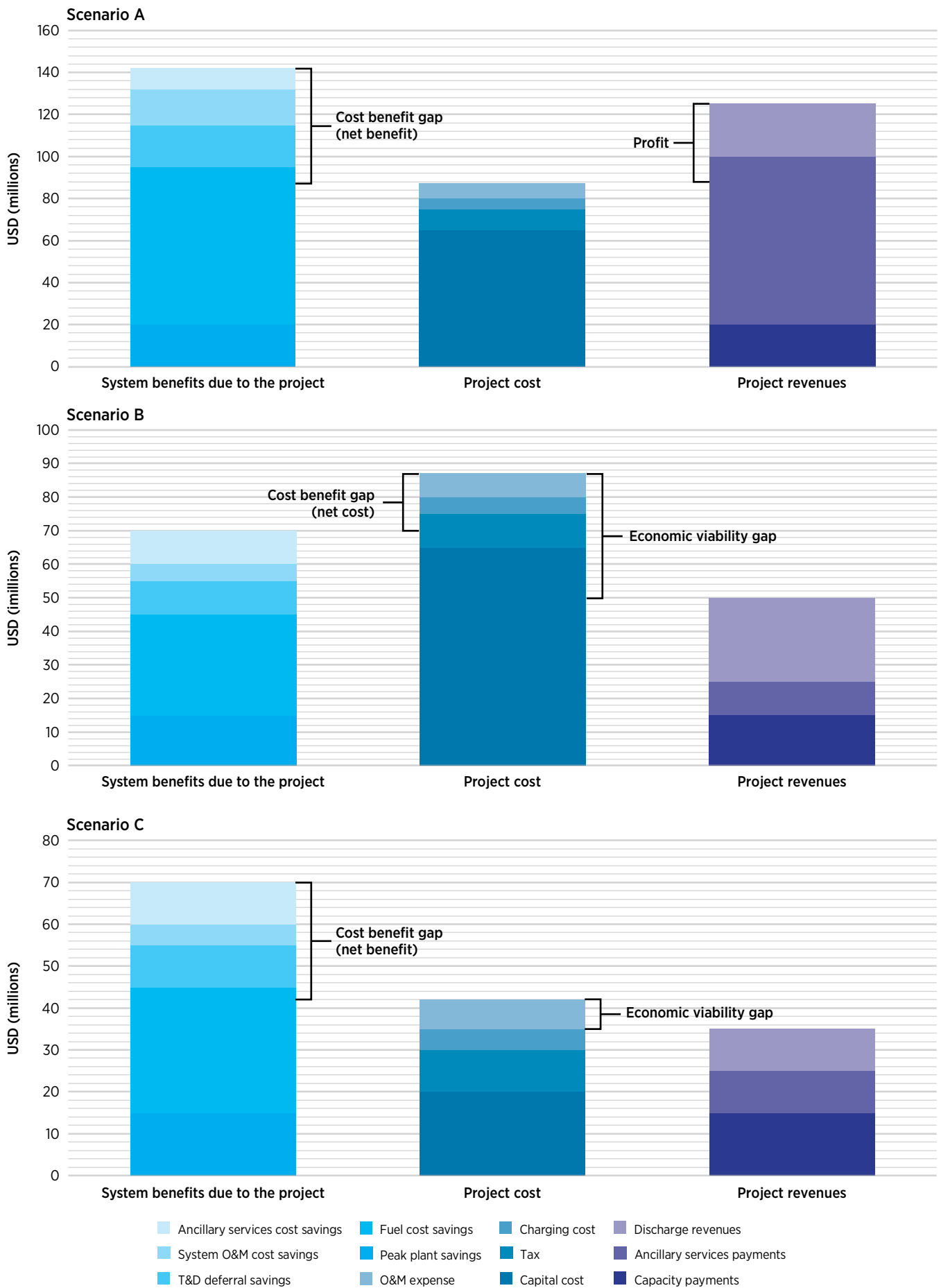


Figure 27: Outcome of three scenarios subject to cost-benefit analysis



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).

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.

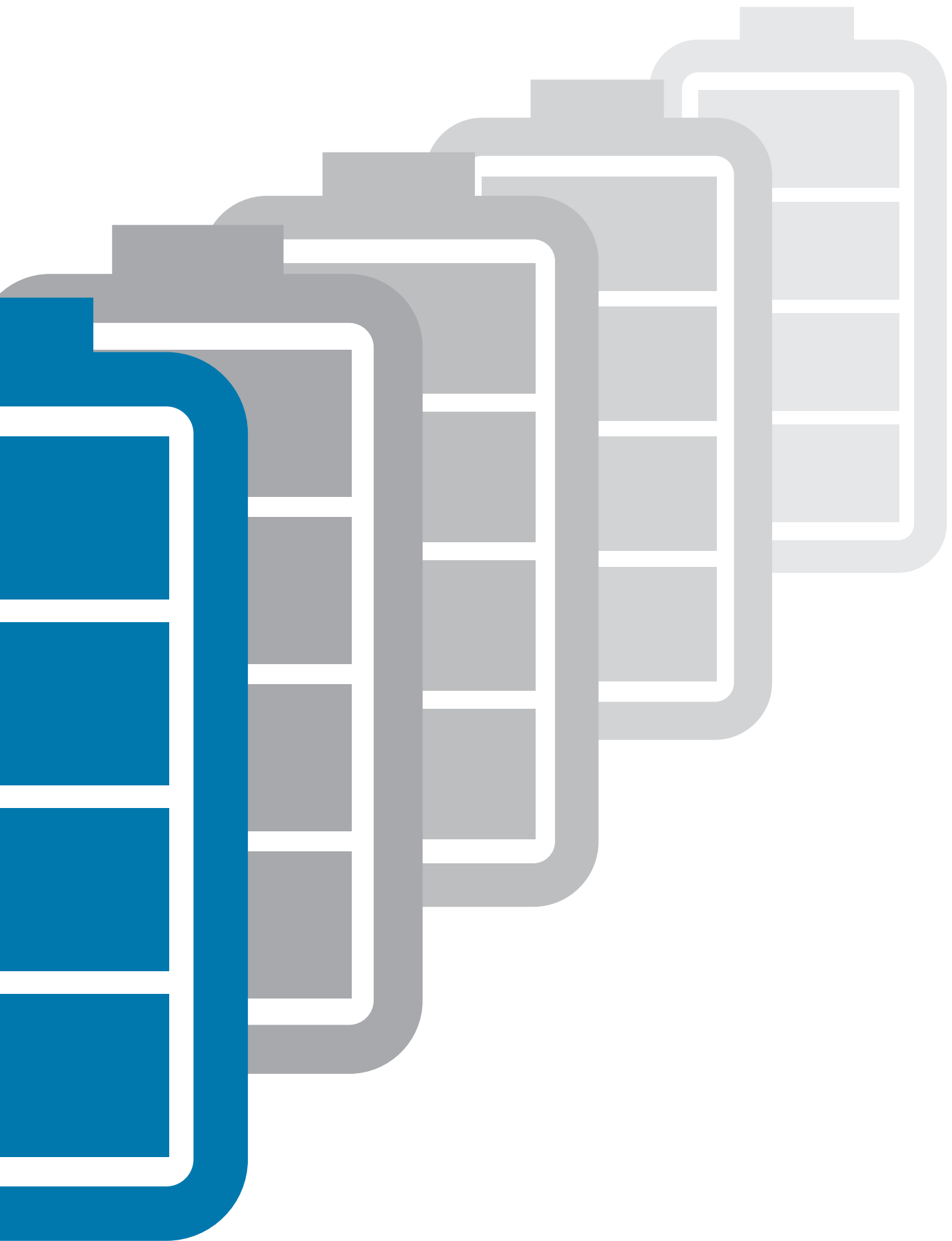
Revenue stacking is crucial to assess the viability and properly value the benefits of electricity storage

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.

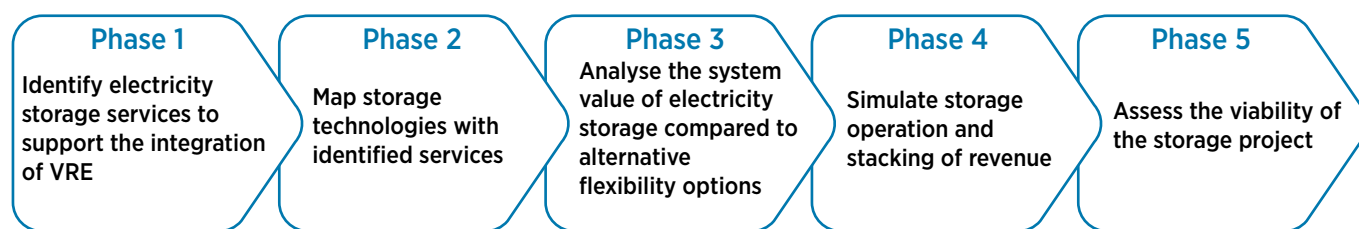
Each case aims to provide concrete examples of a) how such uses are driven by accelerated deployment of VRE, b) how the challenges have been transformed into a business case, c) how this led to storage deployment, and d) how storage is performing in the provision of these services compared to other grid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

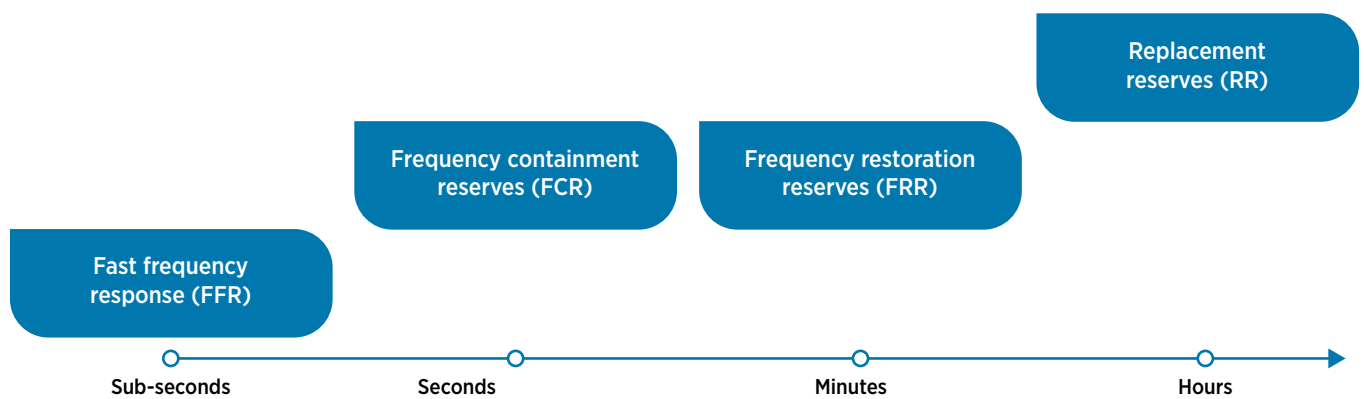
²⁹ Non-synchronous governors can also respond. However, inverters do not have inherent inertia, but inertia-like response can be programmed. Proper response is undergoing research and development.

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.

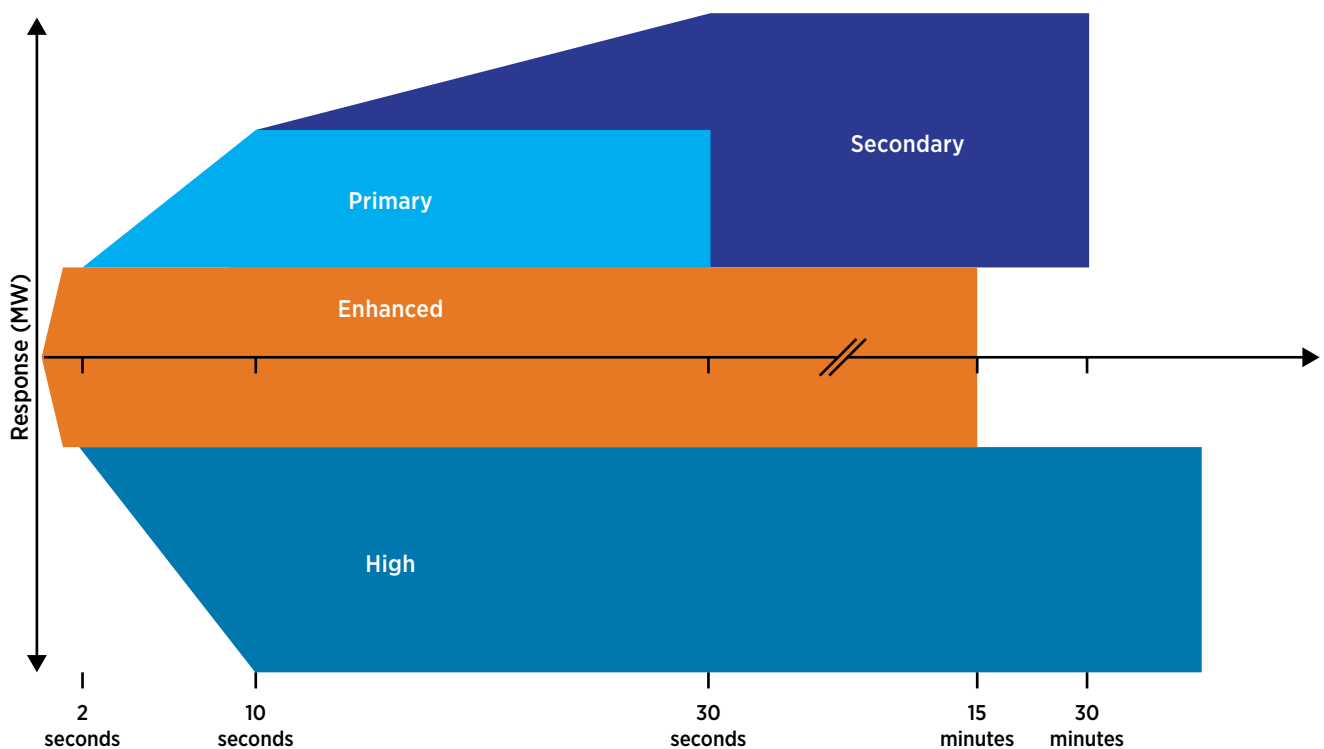
Forecast errors for solar and wind must be taken into account when calculating the system reserve requirements to deal with net load uncertainty

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 Service³¹ (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 is 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

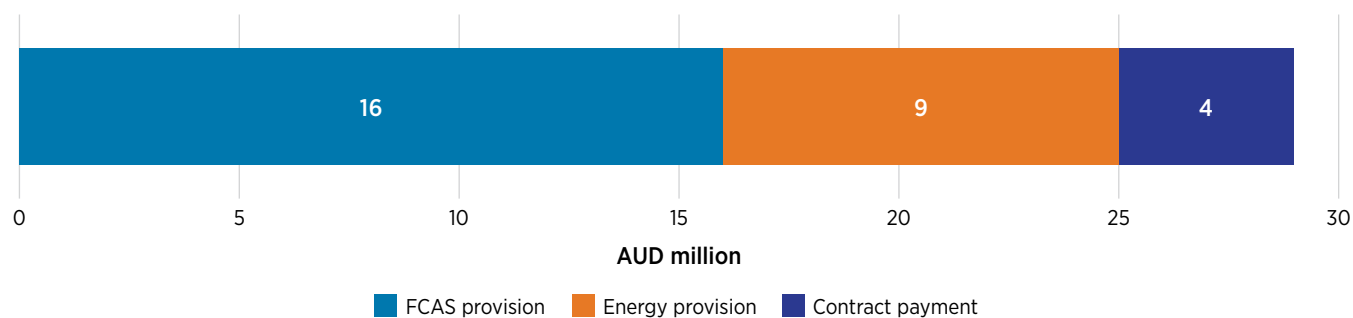
The projects mentioned in the previous section are already operational and supporting their respective power systems with frequency stabilisation.

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.

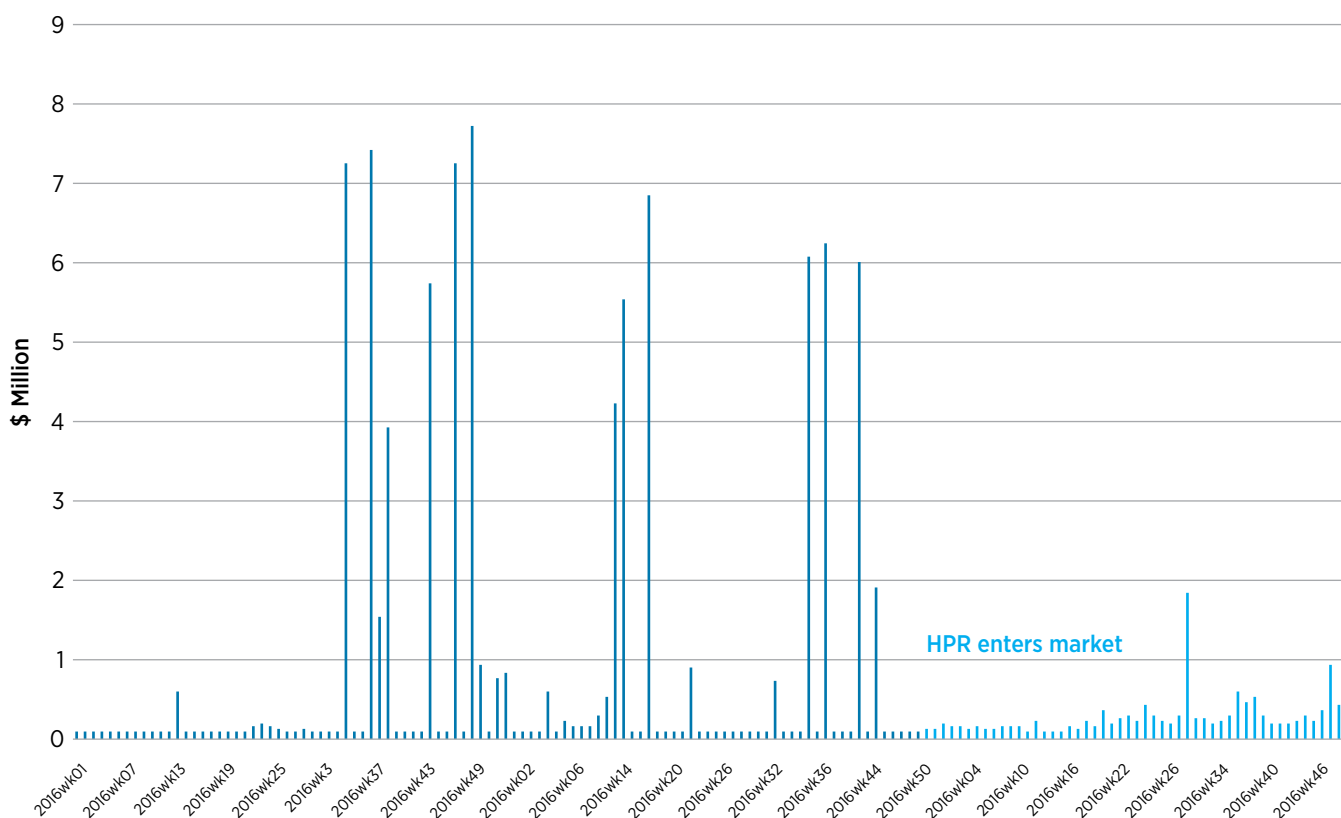
Excluding the yearly AUD 4 million (USD 2.8 million), the battery's total revenues from providing FCAS and arbitrage were AUD 25 million (about USD 17.5 million) in 2018 (Figure 33). Additionally, AEMO stated that in Q4 2018 the battery obtained AUD 4 million from the FCAS market alone (Parkinson, 2019). 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

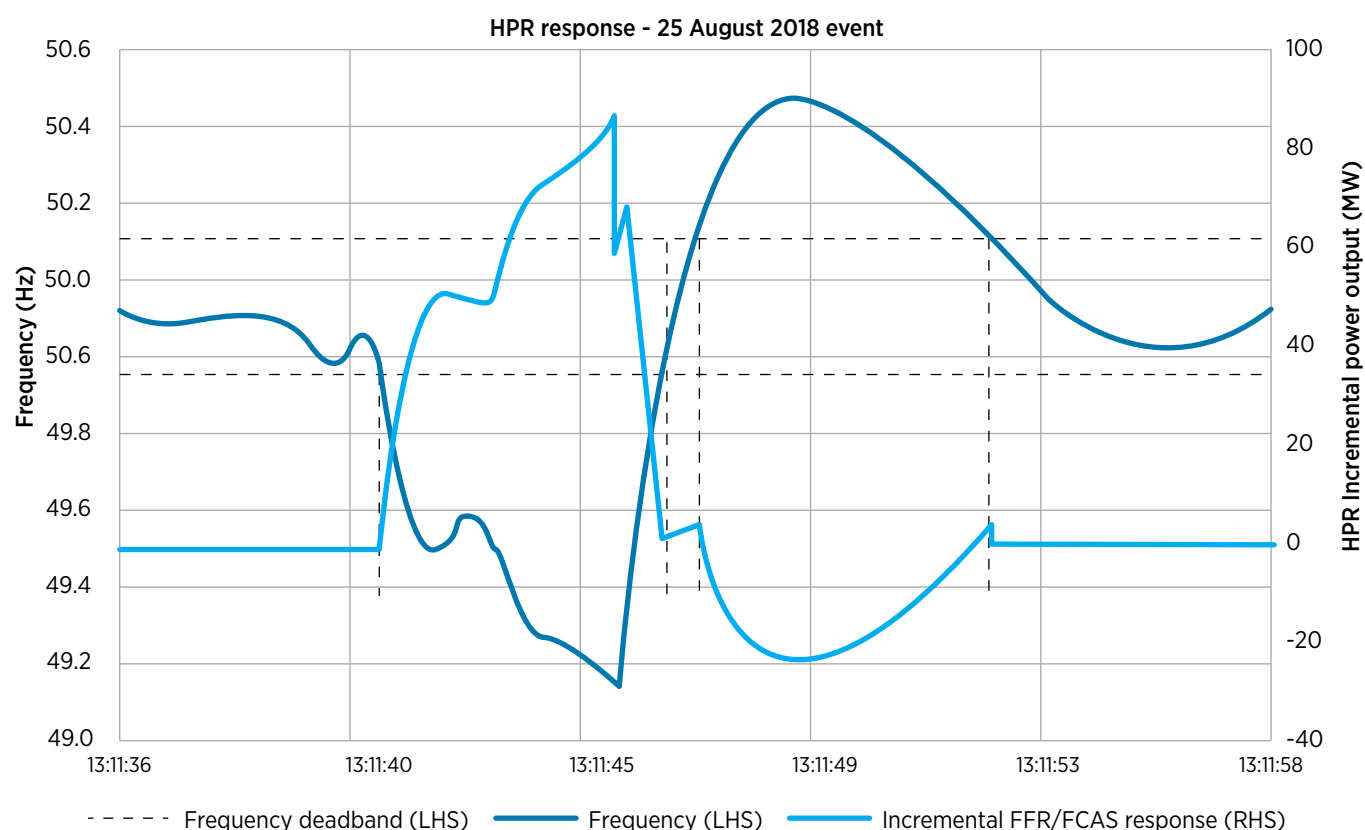


Note: HPR = Hornsdale Power Reserve.
Source: Parkinson (2018).

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

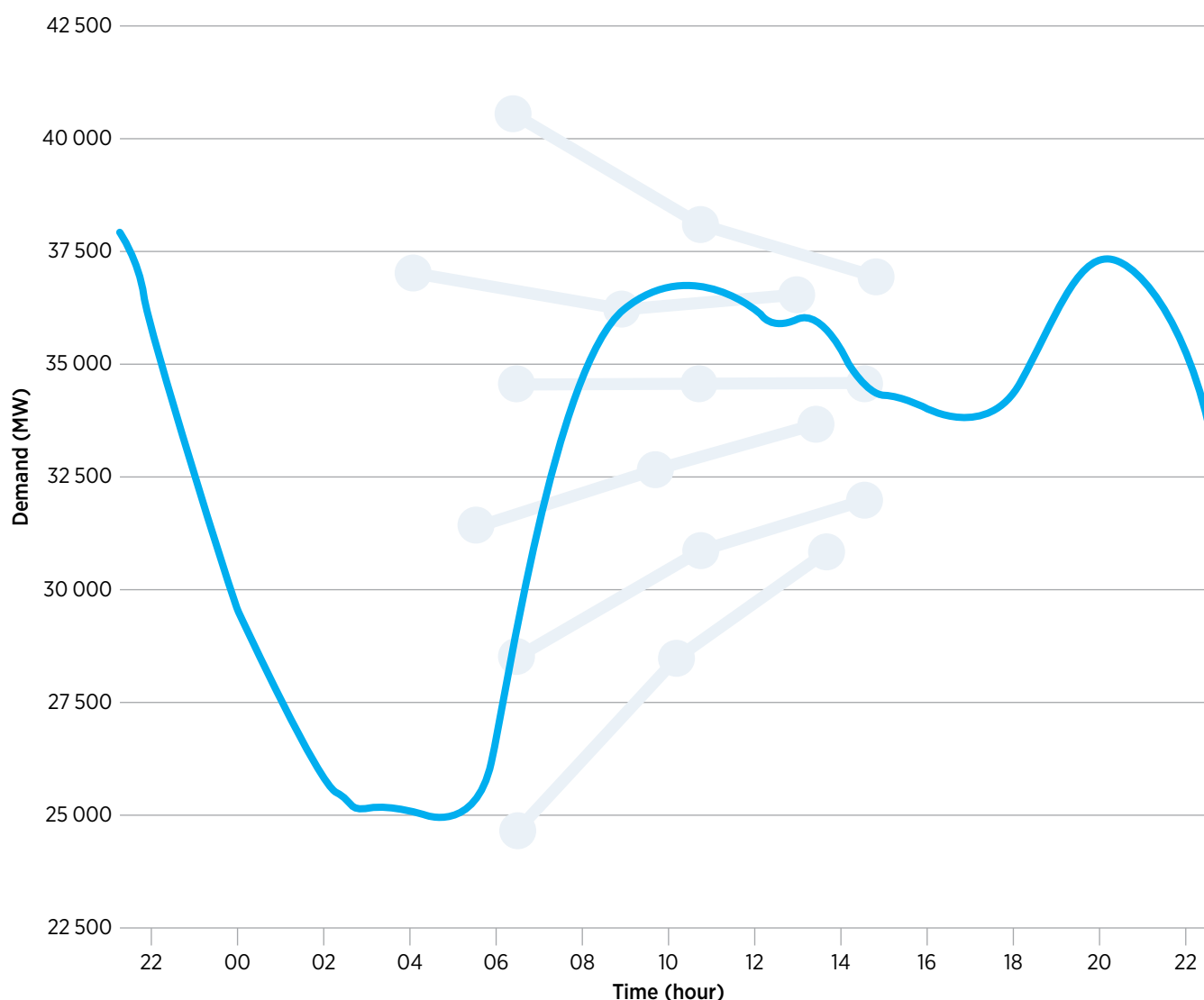
1. Challenge – The duck curve

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.

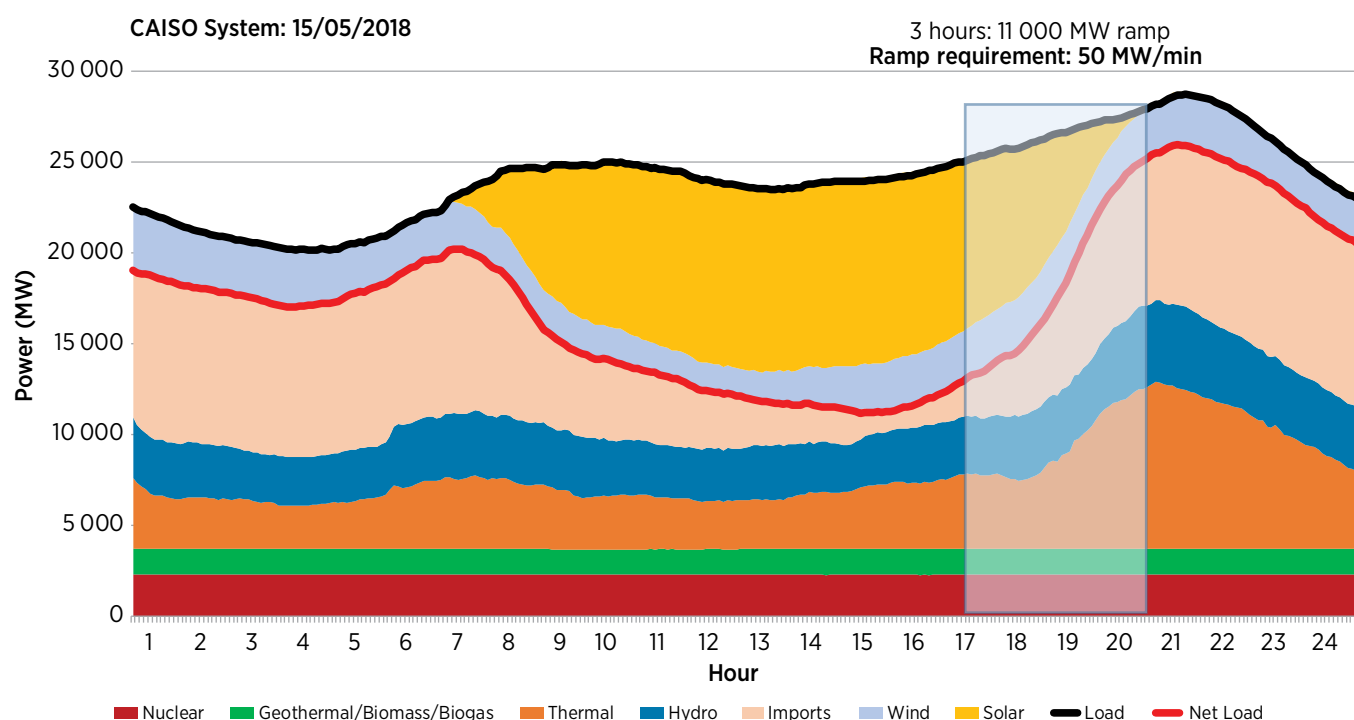
When VRE penetration, and more specifically solar PV penetration, starts to increase, the shape of the net load curve³³ changes dramatically. Solar PV is mainly characterised by its variability: the sun rises in the morning increasing solar PV generation, which is at its maximum towards the middle of 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

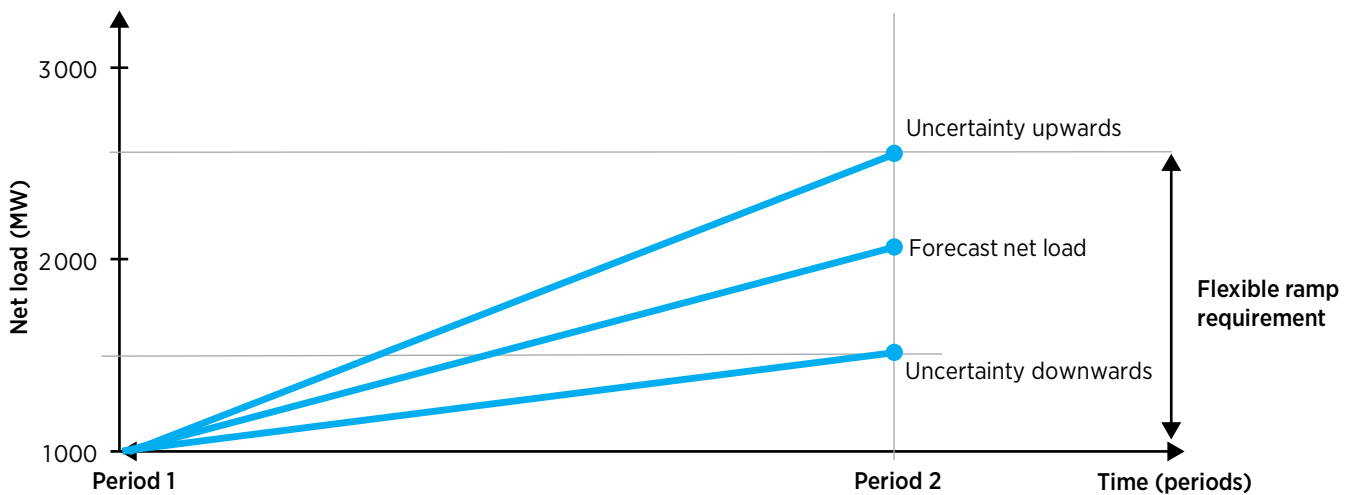
All these solutions provide technical flexibility to the system and help meet the significant ramp requirements of the duck curve. Energy storage, given its capabilities to quickly absorb and discharge energy, could be one of the best solutions to flatten the duck curve.

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).

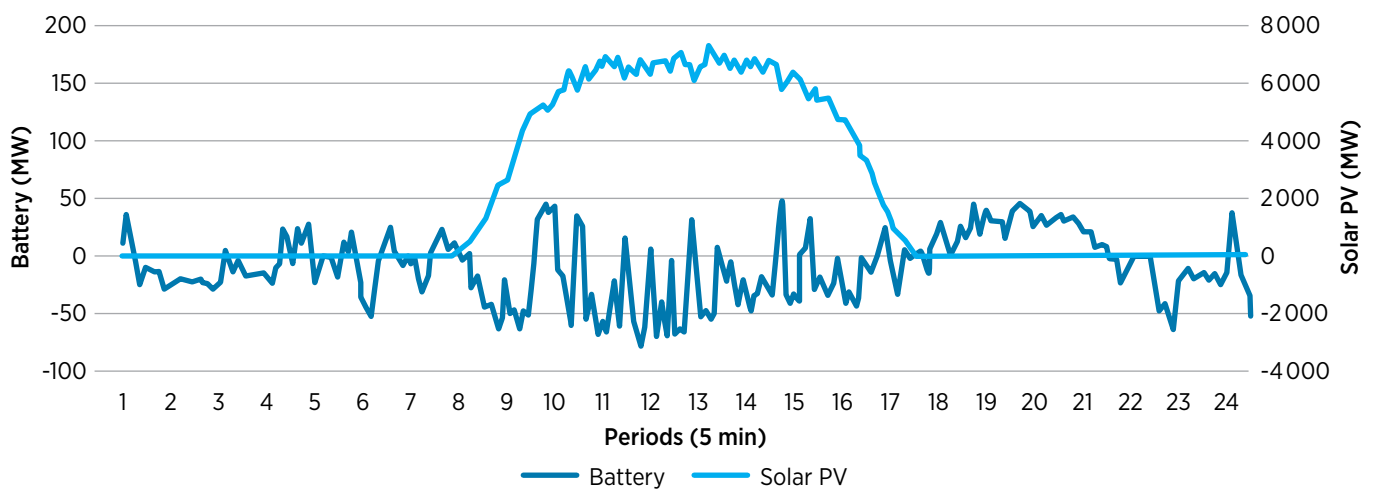
Since 2016 a total of 80 MW of new battery storage systems have been installed in CAISO yielding a total of around 150 MWh, including the largest Li-ion facility in North America at the time (30 MW/120 MWh), located in El Escondido and owned by San Diego Gas and Electric (Davis, 2018).

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 1200 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.

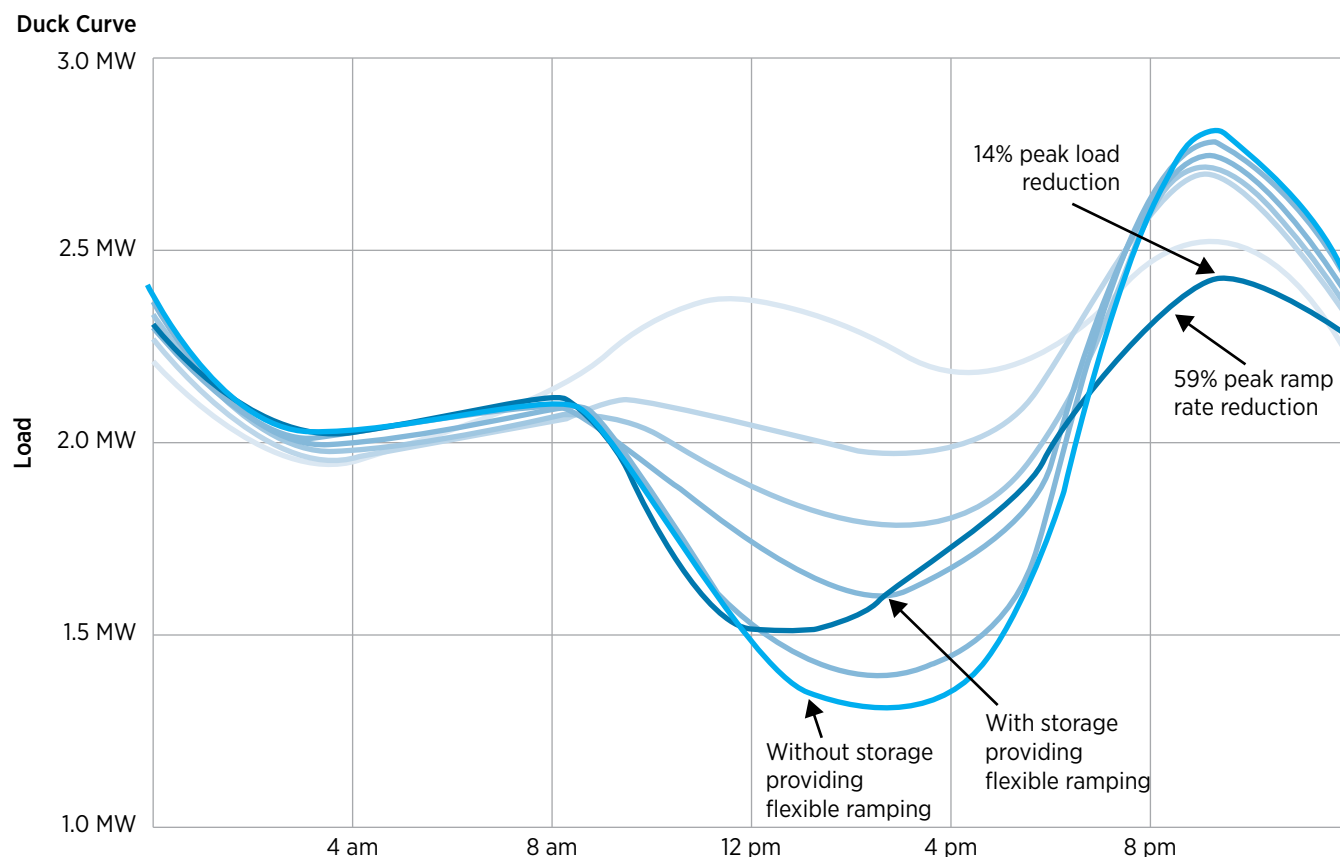
5. Conclusions (Case 2: Flexible ramping)

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”.



Photograph: Freepik

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).

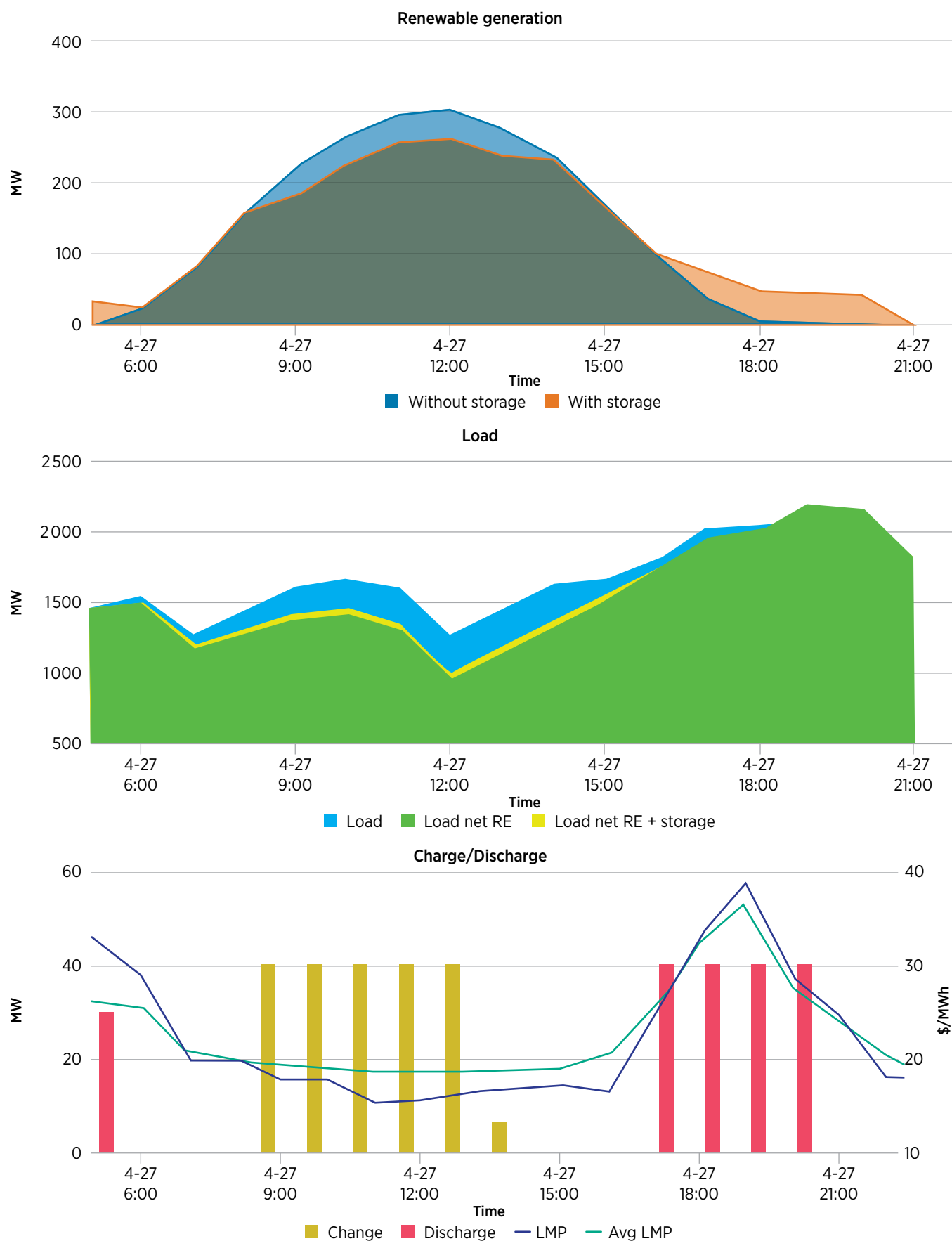
In Figure 41, the blue area (partially obscured by the “With storage” orange area) represents the output of solar PV without energy storage, whereas the orange area represents the combined output of energy storage and solar PV. Part of the VRE production between hours 9 and 14 is stored and used to serve 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

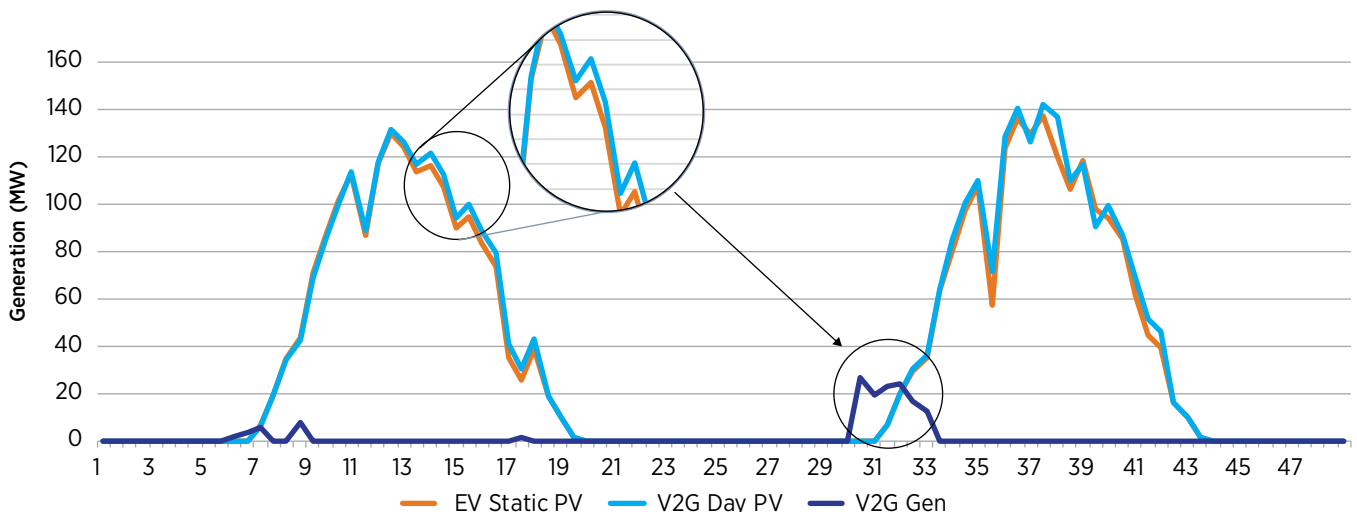
shares of solar, large amounts of energy can be shifted from the peak central hours (when prices are lower) to hours when demand is higher, such as evenings (when prices are higher). By doing so, storage operators can create a strong price-flattening impact using storage, with reasonable monetised revenues. 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.

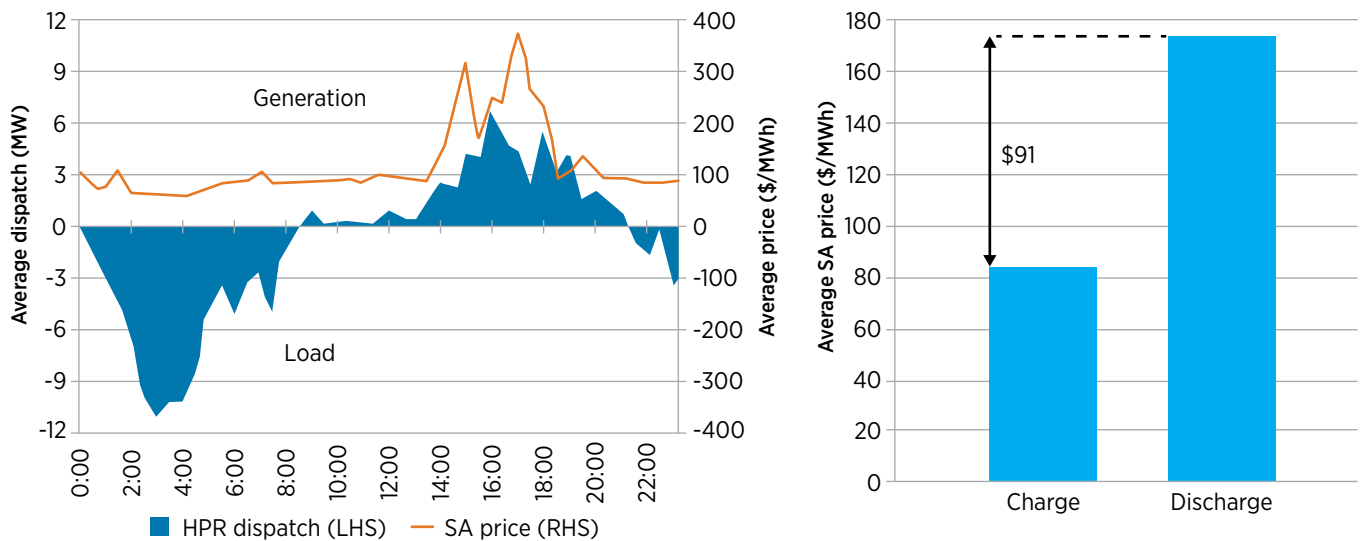
Since its deployment in 2017, the battery system has been providing various services such as energy arbitrage and regulation, and contingency frequency control ancillary services (FCAS) (Aurecon Group, 2018). Moreover, according to the Australian Energy Market Operator (AEMO) the energy arbitrage service 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 (m³). The bottom reservoir is situated near the hydroelectric power station and has a storage capacity of 150 000 m³. 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

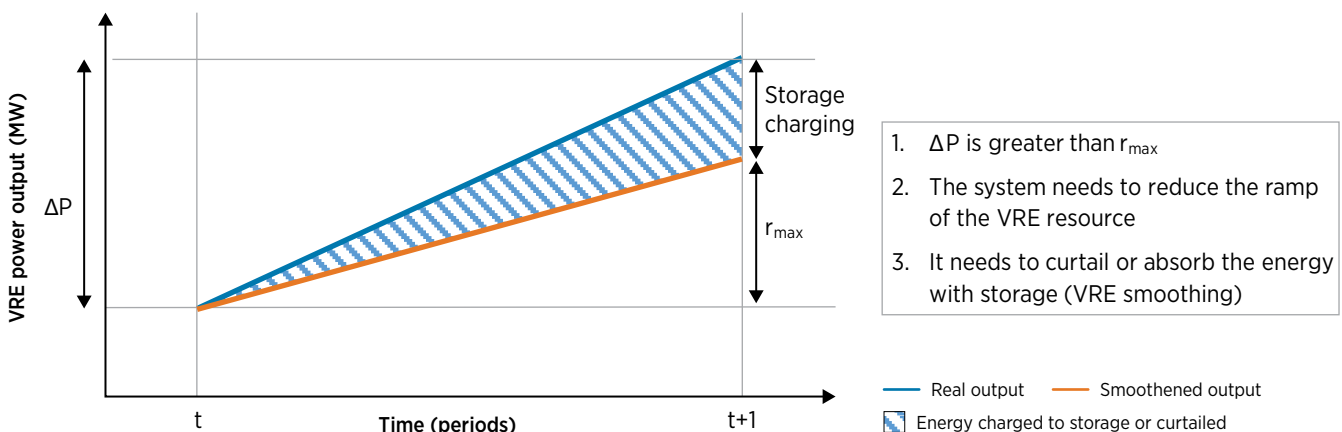


Figure 47: Batteries at the Prosperity energy storage project in New Mexico



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

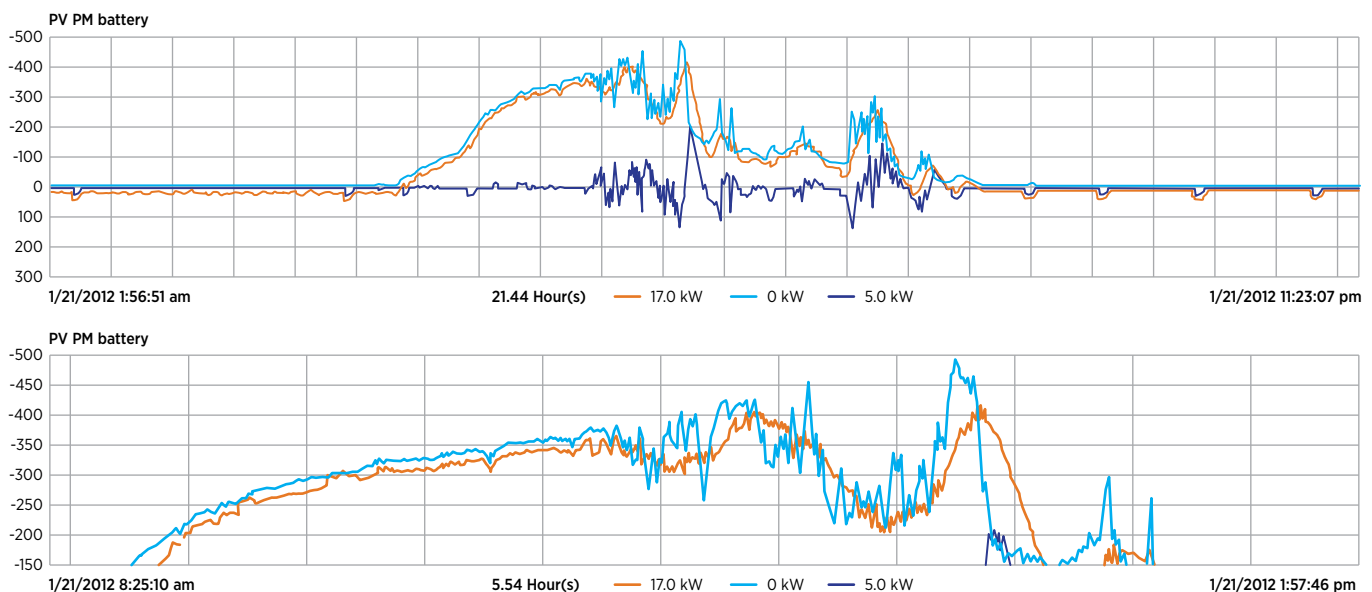
The projects presented in the previous section have been deployed on islands or in small isolated power systems to provide VRE smoothing as a main service. For some of them there is even publicly available information on how to provide this service.

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?

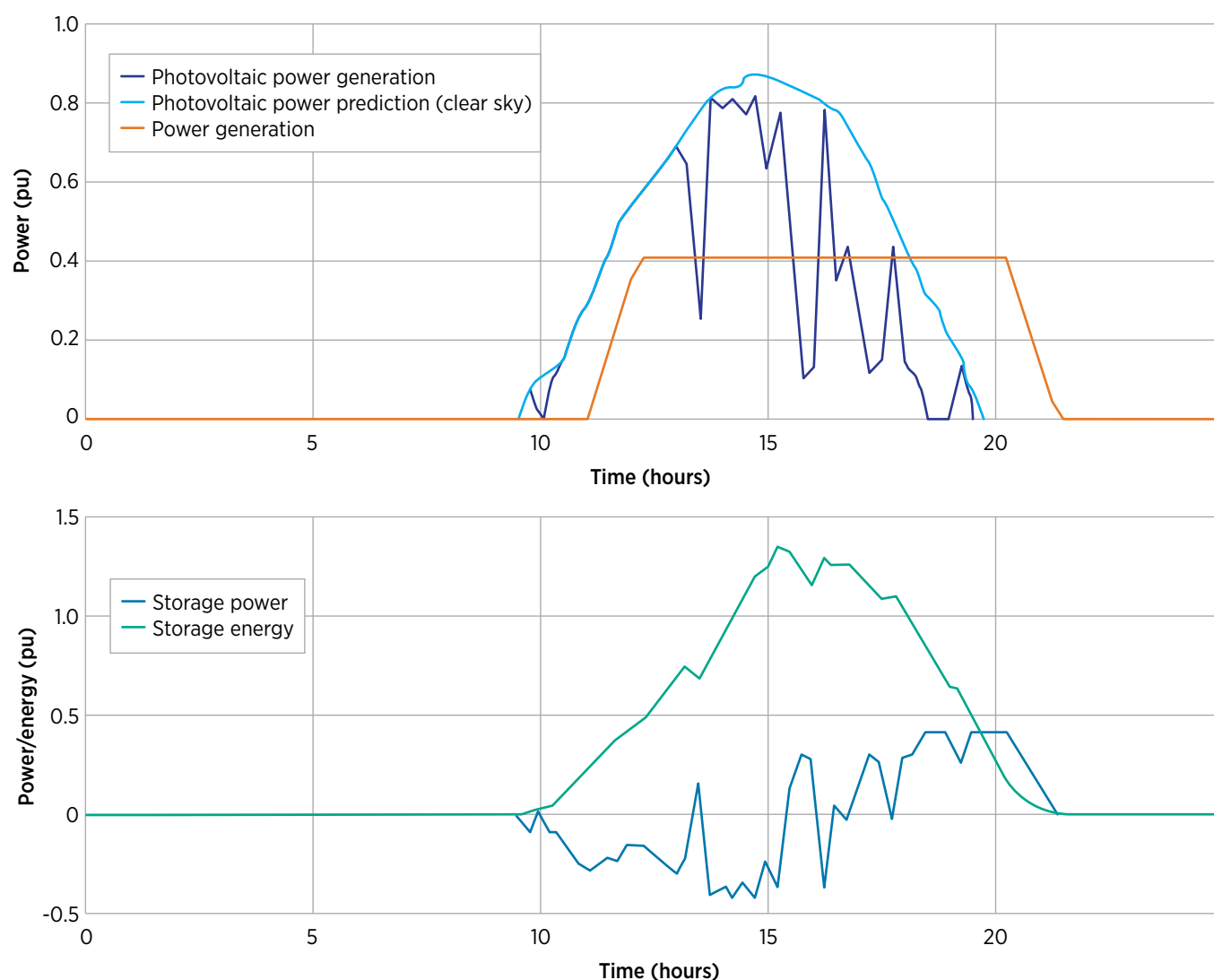
The question now is whether VRE smoothing is a relevant reason to install energy storage systems. The straightforward answer is that installing storage only to provide VRE smoothing is not relevant in most applications, although it may have value in certain niche situations. However, this becomes an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

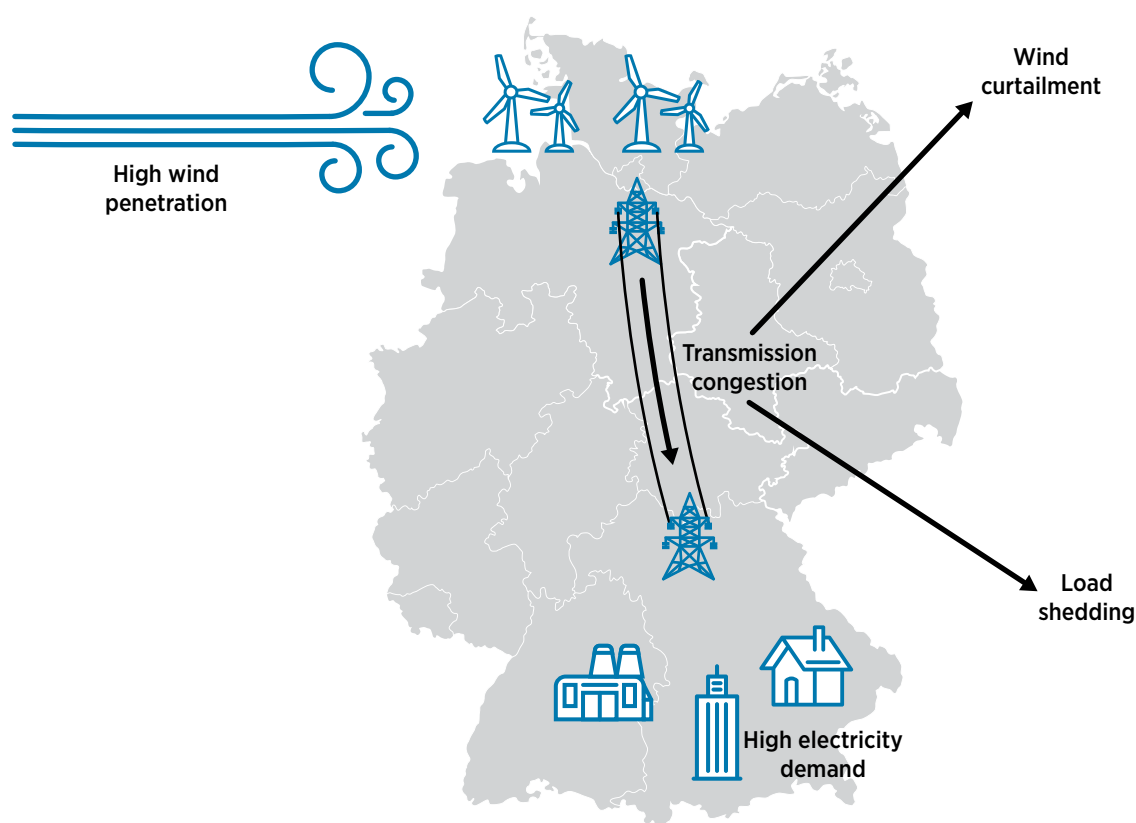
When the system's VRE penetration is high there is a higher risk of T&D congestion that could threaten the security and reliability of the system, due to the variability and uncertainty of VRE resources. In this situation, system operators are sometimes obliged to resort to VRE curtailment as a congestion 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 Palminster 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.

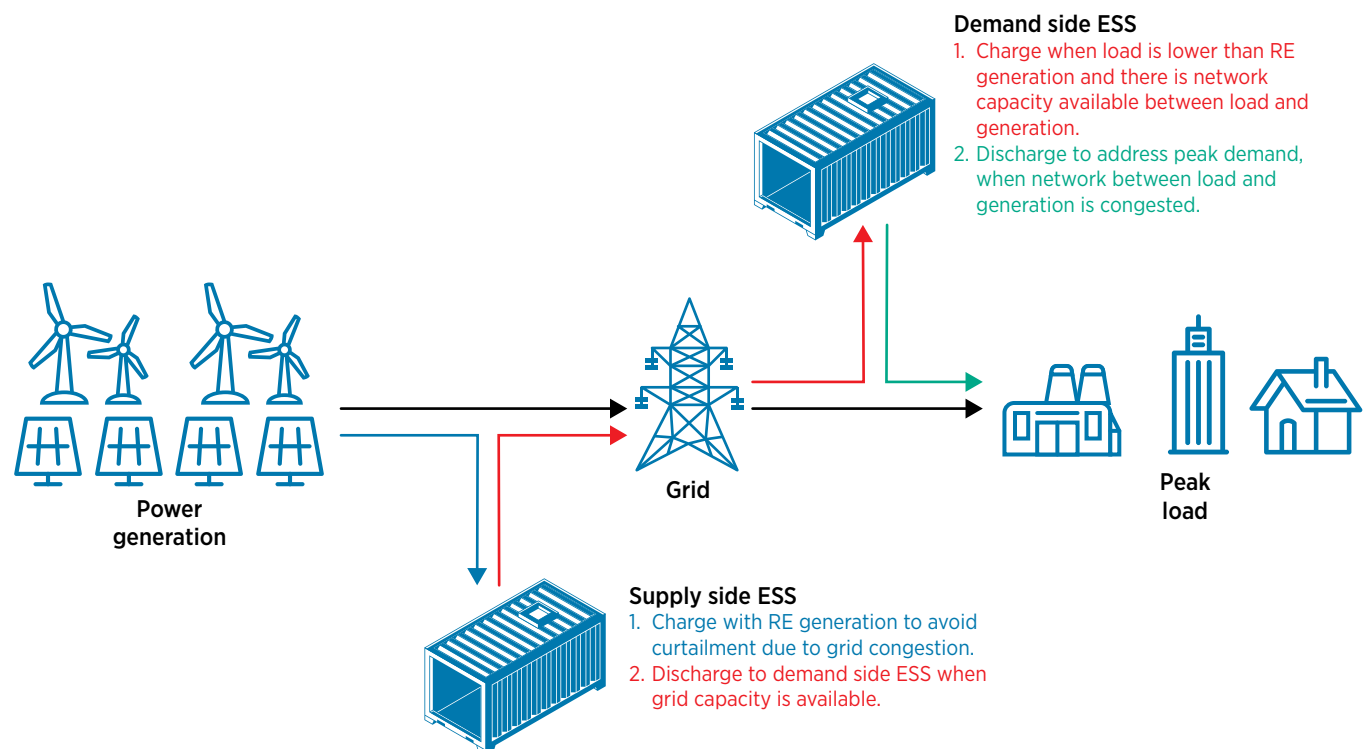
Another option to reduce transmission congestion is dynamic line rating, which consists of better monitoring the thermal conditions of the line to vary the transmission limit. For example, Terna, the Italian system operator, has been applying dynamic line rating in some power lines by better monitoring 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: Wärtsilä

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.



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 establishes 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.

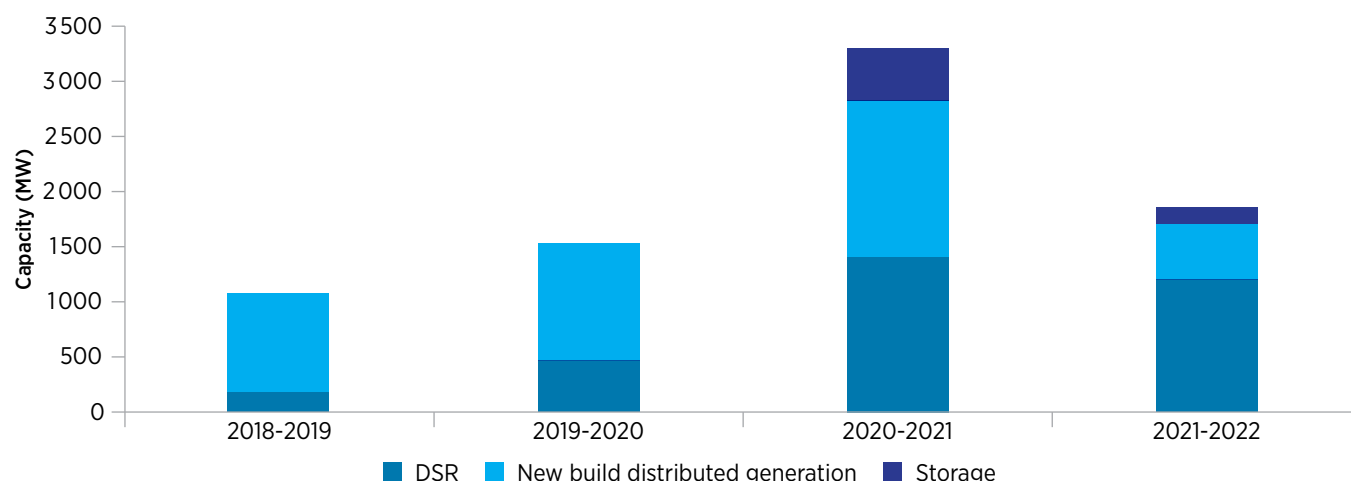
For example, in the United Kingdom the implemented security of supply mechanism allows the participation of storage projects. The mechanism, proposed in 2013 as part of electricity market reform, is a long-term auction for a delayed-delivery reliability product. The mechanism has two types of auctions: 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 factor⁴² 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

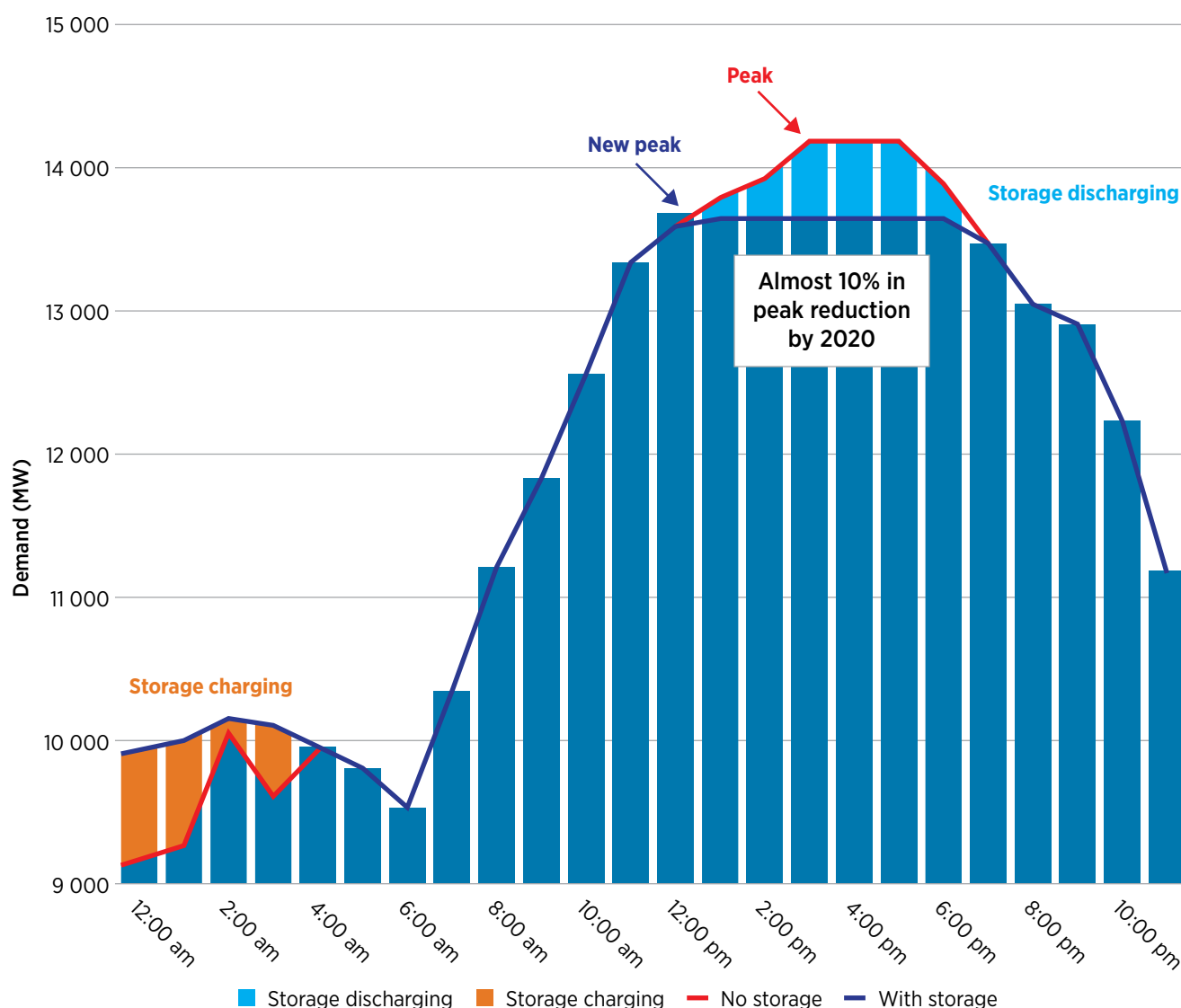
The previous section demonstrates how security of supply mechanisms can yield the deployment of

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

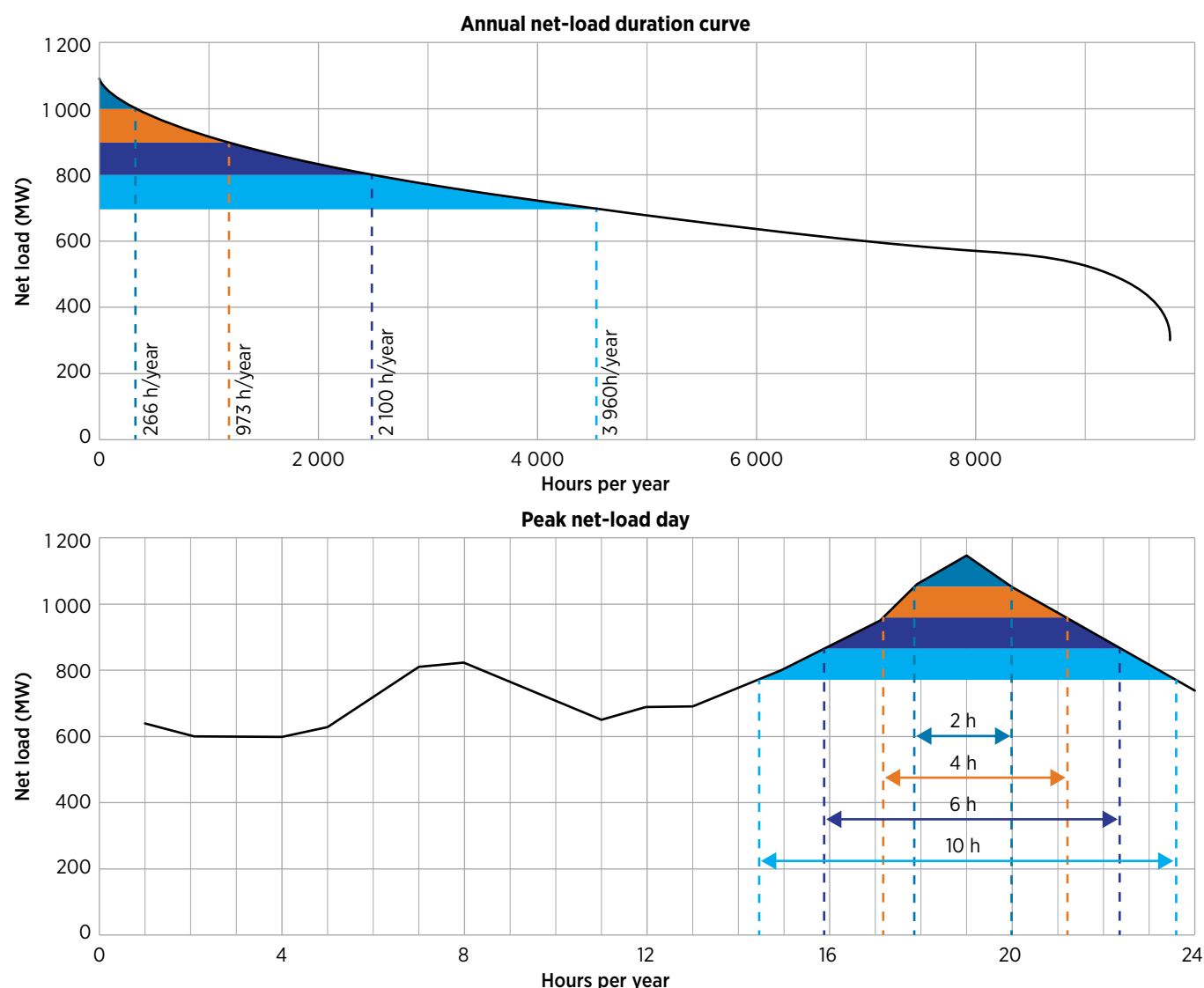


Source: Customized Energy Solutions et al. (2016).

Electricity storage can effectively replace peaking plants 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 increased (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

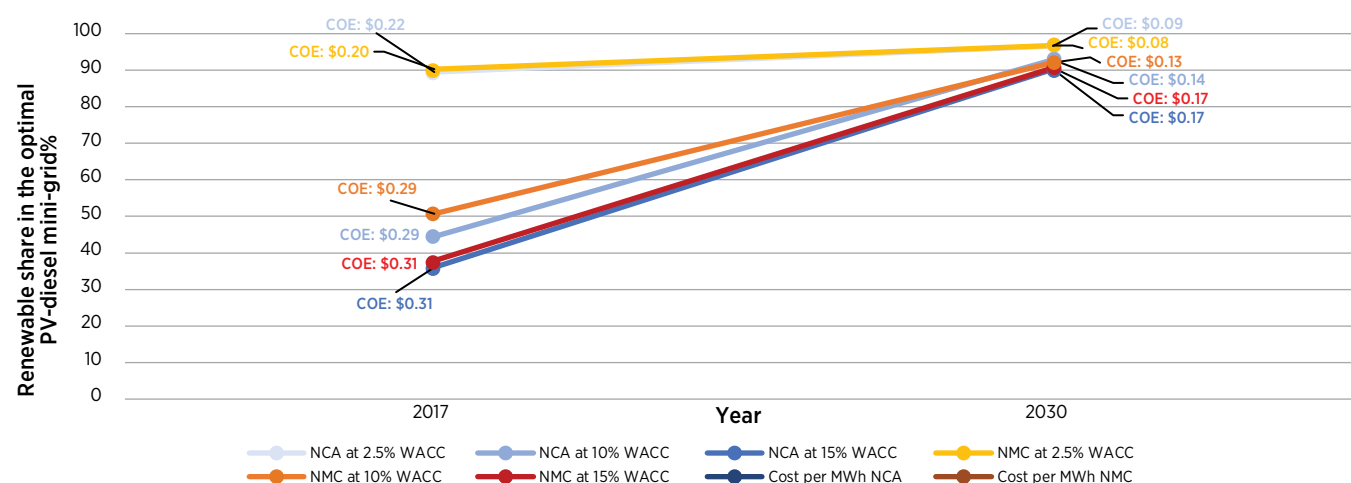
Deploying solar PV with batteries allows not only for energy to be stored and used during times when the sun is not shining, but also greater flexibility as solar PV grows to become the main source of electricity supply in off-grid and weak grid locations. This combination of technologies can be deployed 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 CO₂ 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.



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 (Gracióllica 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.

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

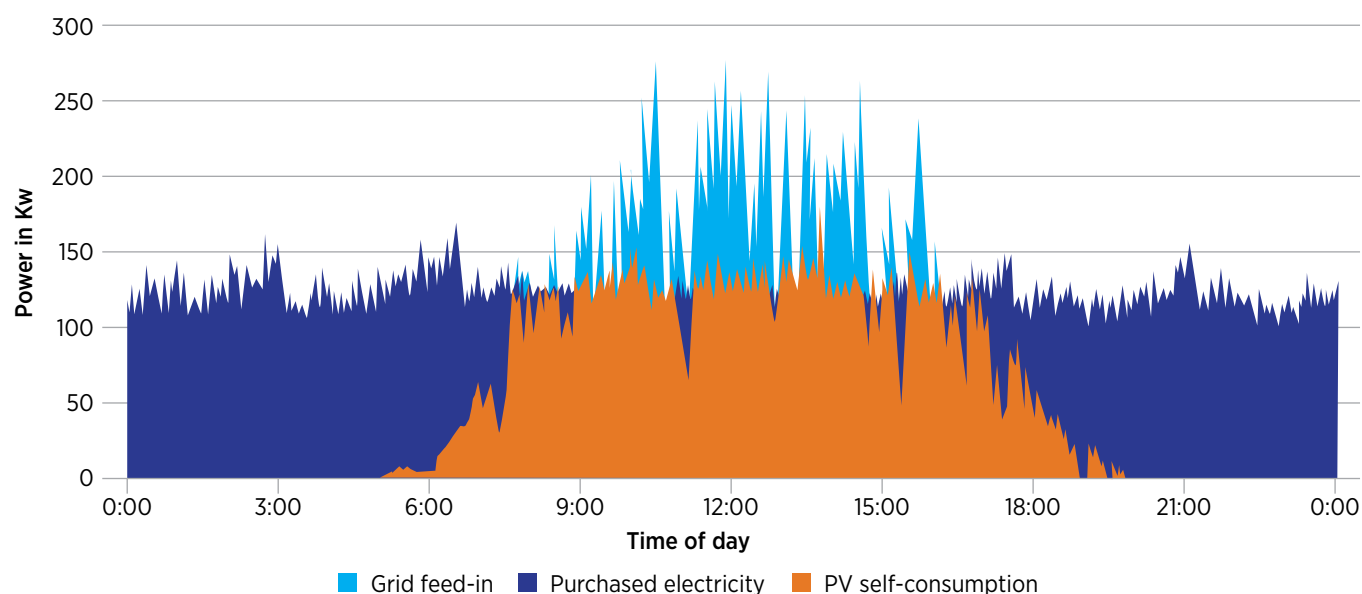
Power systems worldwide are undergoing a deep transformation. Systems that traditionally had a centralised structure with large thermal and hydro generating units are shifting towards a more complex and decentralised system. The increasing penetration of renewable energy, the expansion of markets and 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.

⁴³ www.h2020-migrate.eu.

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,

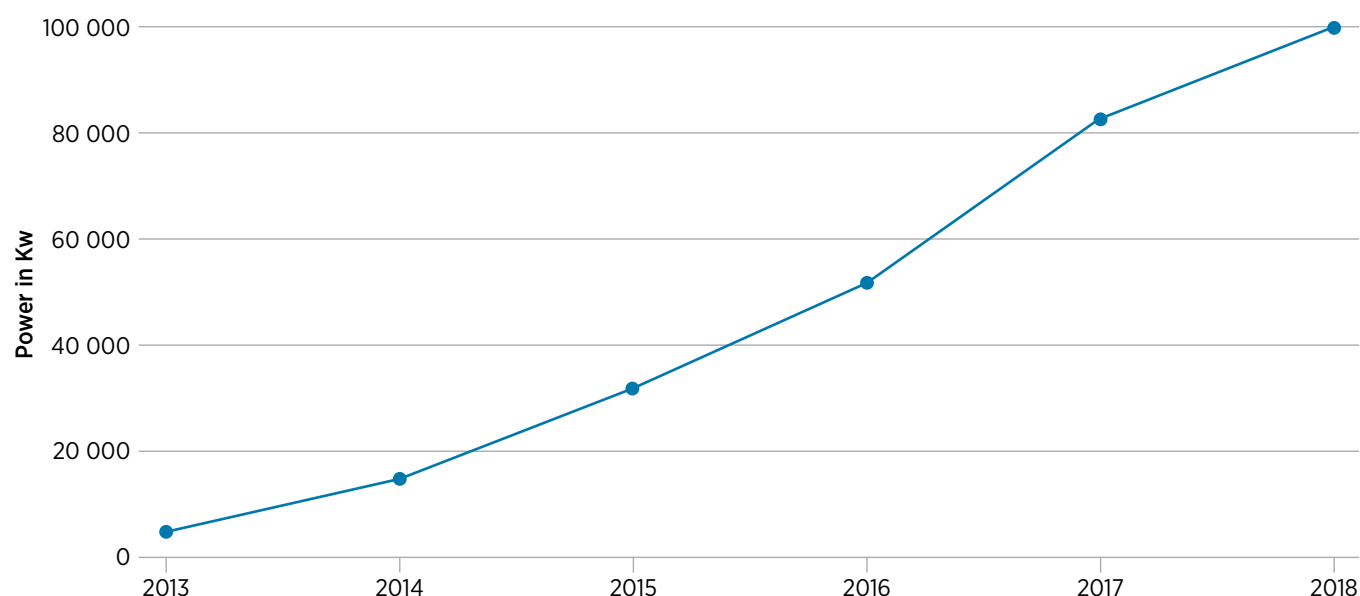
electricity can be still drawn from the grid. Other benefits of BTM storage according to IRENA (2019d) are also:

- 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: Rath, 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).

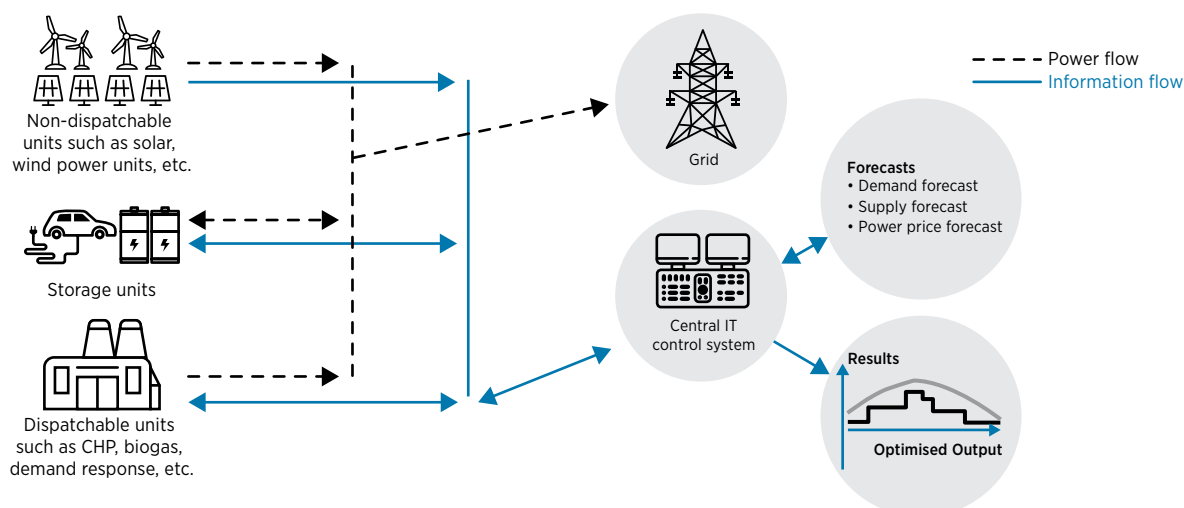
4. Key enablers of BTM energy storage

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).

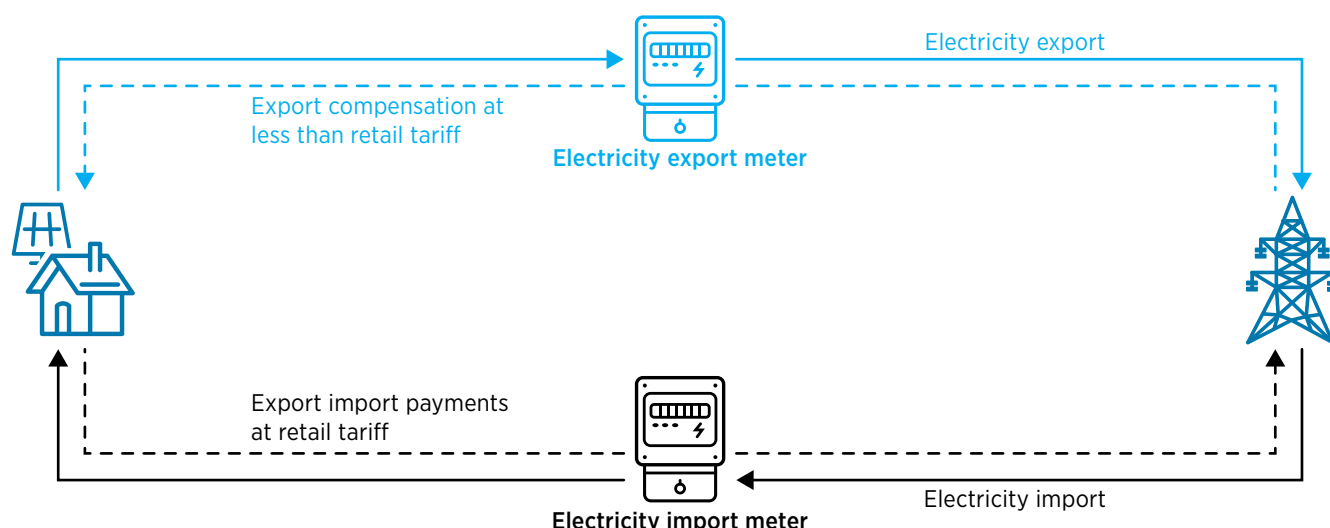
High prices indicate a profitable time to discharge to the grid, thereby earning revenue from the gap between low-price charging and high-price discharging. To do this, however, net billing schemes are required.

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.

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