COMMERCIALISATION OF ENERGY STORAGE IN EUROPE

A fact-based analysis of the implications of projected development of the European electric power system towards 2030 and beyond for the role and commercial viability of energy storage.

Final report, March 2015

STUDY WAS AUTHORED BY THE FOLLOWING 32 COMPANIES AND ORGANIZATIONS

ABENGOA HIDROGENO · AIR LIQUIDE · AkzoNobel · ALSTOM · ECN · elementenergy · eurogas · GERG · HEDNO · HELLENIC PETROLEUM · HIA · HYDROGENICS · INABENSA · ITM POWER · THE LINDE GROUP · moixa TECHNOLOGY · NEL HYDROGEN · NORTHERN POWERGRID · NOW · PROTON ON SITE · PAE RAE · REDT · res AMERICAS · Shell · SIEMENS · Statkraft · Statoil · sunfire · TATA CHEMICALS · VANADIS POWER · VATTENFALL · VOITH

SUPPORTED BY THE

European Commission

THIS STUDY WAS FINANCIALLY SUPPORTED BY THE FUEL CELL AND HYDROGEN JOINT UNDERTAKING (FCH JU).

FCH FUEL CELLS AND HYDROGEN JOINT UNDERTAKING

The FCH JU believes that it is essential to understand the future demand for energy storage covering a wide range of options from a technology-neutral point of view. As a programme managing public money, the FCH JU needs to know through unbiased assessment which fuel cell and hydrogen applications are worthwhile to support. Hence it initiated the current fact-based study carried out by a large coalition representing different technologies and players in the energy storage market.

McKinsey & Company, the management consultancy, provided analytical support for the study. Any recommendations or positions taken in this report are the responsibility of the authors, not of McKinsey & Company.

Table of Contents

Executive Summary

WHY WAS THIS REPORT CREATED AND WHO IS IT FOR?

This report was created to ensure a deeper understanding of the role and commercial viability of energy storage in enabling increasing levels of intermittent renewable power generation. It was specifically written to inform thought leaders and decision-makers about the potential contribution of storage in order to integrate renewable energy sources (RES) and about the actions required to ensure that storage is allowed to compete with the other flexibility options on a level playing field.

The share of RES in the European electric power generation mix is expected to grow considerably, constituting a significant contribution to the European Commission's challenging targets to reduce greenhouse gas emissions. The share of RES production in electricity demand should reach about 36% by 2020, 45-60% by 2030 and over 80% in 2050.

In some scenarios, up to 65% of EU power generation will be covered by solar photovoltaics (PV) as well as on- and offshore wind (variable renewable energy (VRE) sources), whose production is subject to both seasonal as well as hourly weather variability.

This is a situation the power system has not coped with before. System flexibility needs, which have historically been driven by variable demand patterns, will increasingly be driven by supply variability as VRE penetration increases to very high levels (50% and more).

Significant amounts of excess renewable energy (on the order of TWh) will start to emerge in countries across the EU, with surpluses characterized by periods of high power output (GW) far in excess of demand. These periods will alternate with times when solar PV and wind are only generating at a fraction of their capacity, and non-renewable generation capacity will be required. In addition, the large intermittent power flows will put strain on the transmission and distribution network and make it more challenging to ensure that the electricity supply matches demand at all times.

New systems and tools are required to ensure that this renewable energy is integrated into the power system effectively. There are four main options for providing the required flexibility to the power system: dispatchable generation, transmission and distribution expansion, demand side management, and energy storage. All of these options have limitations and costs, and none of them can solve the RES integration challenge alone. This report focuses on the question to what extent current and new storage technologies can contribute to integrate renewables in the long run and play additional roles in the short term.

FIGURE 1

This study focuses on energy storage, 1 of the 4 main technological options for the integration of VRE

WHAT STORAGE TECHNOLOGIES WERE CONSIDERED IN THE STUDY?

Energy storage fulfils three functions: to charge, to hold and to discharge energy. In this study, we consider power-to-power (P2P) storage where the energy carrier that is charged and discharged is electricity, as well as conversion to other carriers (heat and hydrogen) where electricity is charged and the energy is released from storage outside the electric power system in the form of hydrogen or heat. In particular, we consider three types of storage technologies:

- P2P (e.g., pumped hydro, compressed and liquid air, Li-ion, flow and lead-acid batteries, electrolytic hydrogen production and re-electrification)
- Conversion of power to heat and storage of heat for final consumption
- Conversion of power to hydrogen for use outside the power sector (e.g., power to gas (P2G), use as fuel for mobility or in the industry).

HOW WAS THIS STUDY PREPARED?

This study was prepared by a broad coalition of organisations, including storage technology developers, utilities, energy companies, research institutions, regulatory authorities and European institutions.

The power systems of four European countries or regions (Germany, Spain, Sweden and the Greek island of Crete) were chosen for modelling based on their differing characteristics. For each country, the electric power supply-demand balance was modelled in high temporal resolution for three years with successively increasing RES penetration (2014, 2030 and 2050). The RES penetrations were treated as an exogenous input from scenarios developed by the European Commission and cover the whole spectrum of RES penetration targets for 2030 and 2050.

The key outputs were the amount of excess electricity, the required non-RES power generation and capacity as well as the costs of the non-RES generation, including costs of CO2. Based on this model, we studied the decrease in non-RES generation costs at different installed storage capacities. In addition, we examined the ability of conversion to heat and hydrogen to utilise the excess renewable energy.

The model extensively tested the sensitivity of storage demand to three transmission and distribution (T&D) grid constraint scenarios: no international constraints, no internal constraints, severe internal T&D and must-run constraints.

In determining the cost trajectory of the individual storage technologies, the study relied on previously published and widely accepted literature. No independent review of technology cost forecasts was conducted as part of this study, nor were sources prioritised to allow for "cherry-picking" between technologies. The analysis focused on a pure techno-economic evaluation: neither additional barriers for implementation (such as safety and societal acceptance) nor the effect of non-economic decision-making were taken into account.

Although the report already includes aggressive cost reduction targets for the storage technologies, more aggressive cost reductions and performance improvements would further improve the business case and penetration of storage. For example, further 75% reduction in storage costs compared to low range of estimates could lead to an increase of demand for storage by a factor exceeding 4 in some scenarios. Hence, realized performance and costs of the technologies will have to be monitored on an ongoing basis.

WHAT MAKES THIS STUDY UNIQUE?

While there are many reports covering individual aspects of energy storage (e.g., technology cost improvements, integration of home PV solar), this report covers the topic end-to-end, considering the development of the electric power system, advances in storage technologies, business cases for storage deployment and the regulation of storage.

In addition, the study does not only consider the electric power sector but also examines the conversion of electricity to other carriers and the role it can play in the integration of different parts of the broader energy sector (electric power, heating, gas grid).

Finally, the study was authored by a diverse coalition of organisations and benefited greatly from the perspectives of a wide range of stakeholders in the energy sector.

WHAT ARE THE KEY FINDINGS?

The study shows that both P2P storage and conversion to other carriers have the potential to play an important role in providing flexibility to the power system. They will make it possible to ensure that large amounts of renewable energy are not wasted, but are rather used to reduce the amount of required non-RES generation and decarbonise heating, transportation and the gas grid. However, in order for storage technologies to develop, regulators need to create a level playing field on which storage can compete with other flexibility options.

1. Demand for P2P storage will grow up to 10 times

In the high-RES scenario (60% and more VRE penetration by 2050), there will be economic potential for very large amounts (up to 10 times the currently installed capacity, or about 400 GW in the EU) of P2P storage for the integration of intermittent renewable energy. Storage demand in the 2030 horizon will depend on country-specific characteristics, in particular on the level of interconnectivity.

2. Ability of P2P storage to integrate VRE: P2P storage will neither fully eliminate the need for non-RES generation nor be able to utilise all excess renewable electricity

Even with a tenfold increase in installed P2P storage capacities, a significant amount of backup non-renewable generation and large installed non-RES power plant capacity would still be required for prolonged periods (several days) with low wind and sunshine. At the same time, in the high-RES scenario, there would still be periods with large amounts of excess renewable energy that could not be used in the electric power system directly or through P2P storage.

3. Demand for storage is largest in island systems and smallest in countries with large reservoir hydro capacity

Demand for storage differs significantly between countries with different generation profiles. In particular, large reservoir hydro capacity such as in Sweden is a carbon-free option to integrate renewables and eliminate the need for further storage. By contrast, non-interconnected islands, or markets that behave as such, are a suitable early market for storage driven by emerging renewables curtailment and very high fossil generation costs. Depending on the island characteristics, there already may be economic demand for storage reaching tens of percent of installed power generation capacity.

4. Ability of conversion of power to heat to integrate VRE: conversion of power to heat can contribute to VRE integration, but its potential is limited by heating-related electricity demand

Conversion of electricity to heat and heat storage is a proven and relatively low-cost option for providing flexibility to the power system. As increasing VRE penetration and higher fuel and CO2 costs will drive higher volatility in electricity prices, the business case for and penetration of heat storage will improve further. Conversion to heat and heat storage will be able to utilise a part of the excess renewable energy and reduce the required non-RES generation. However, the potential of conversion to heat to integrate VRE is limited by the share of electricity demand used for heating and by its seasonality.

5. Ability of conversion to hydrogen to integrate VRE: conversion of electricity to hydrogen for use outside the power sector has the potential to productively utilise nearly all excess renewable electricity that would be curtailed

Conversion of electricity to hydrogen through water electrolysis and use of this hydrogen in the gas grid (P2G), mobility or industry can productively utilise nearly all excess renewable energy in the high-RES scenario, contributing to the decarbonisation of these sectors. European potential for installed electrolyser capacity in 2050 high-RES scenarios would be in the hundreds of GWs. This requires that there either is local demand for hydrogen at the production site or that the hydrogen can be economically transported to a demand centre.

6. Energy storage can create value in the short run, but reviewing regulation is key to unlocking this opportunity

Proven and emerging storage technologies have economically viable uses in the short run and can contribute to meeting the flexibility needs of the power system while creating value for society. These applications include time shift in island systems, deferral of T&D upgrades, provision of frequency reserve and home storage coupled with PV. Accessing these markets will require a review of the regulation that currently prevents storage from participating in the market on a level playing field with the other flexibility options. The overall impact of storage with large energy capacities substituting non-RES generation in VRE-based energy systems needs to be assessed in more depth in further studies.

7. Key regulatory obstacles to energy storage can be lifted by fair consideration of the role of storage in the electric power value chain

There is a low degree of regulatory acknowledgement of storage as a specific component of the electric power value chain – and hence a lack of storage-specific rules and insufficient consideration of the impact of regulation on storage. The key obstacles to storage identified by the study are:

- Lack of clarity on the rules under which storage can access markets – in particular the inability of transmission system operators (TSOs) and distribution system operators (DSOs) to own and operate storage or purchase T&D deferral as a service in some countries or lack of rules concerning the access of storage to the ancillary services market
- Application of final consumption fees to storage (including P2G), even though storage does not constitute final use of the energy
- Payments for curtailment to RES producers, removing an incentive for productive use of the curtailed electricity.

WHAT ARE THE NEXT STEPS?

The next steps following this study should focus on assessing the holistic implications on a country level for the various flexibility options, including storage, realising the projected cost trajectories and progressing on solving the regulatory barriers.

The study shows that the role P2P storage and conversion to other carriers will play in the future will differ greatly from country to country based on factors such as electricity generation fleet, level of T&D interconnectedness or heating demand. This role will be further shaped by the extent to which demand side management is able to economically adapt demand patterns to electricity supply – a variable that has not been researched within this study. To obtain a more precise picture of future storage needs, holistic individual country analyses would be required, fully taking into account local specifics of (flexible) power generation, demand, T&D and the opportunity for demand side management.

This study assumes significant storage technology cost reductions between now and 2030. In order for these cost reductions to materialise, concerted action is required by all stakeholders (OEMs, utilities, system integrators, regulators, etc.) to enable storage deployment in the early markets identified in the study. Also, these stakeholders need to work together on overcoming the technical, safety and societal acceptance hurdles of large-scale storage deployment.

Most important regulatory obstacles to the participation of storage in the market and directions to remove them have been identified. Governments and regulators need to conduct further detailed analysis of the needed regulatory changes, and their impact on the various stakeholders is required in order to make further progress.

Introduction and objectives of the study

The objective of the study is to assess the role and commercial viability of energy storage (both P2P and conversion of power to heat and hydrogen) in light of the projected development of the European electric power system towards 2030 with an outlook to 2050.

It focuses on the translation of the impact of increased RES penetration on demand for and value of energy storage services.

The study is intended for a wide variety of stakeholders – from policy makers and investors to OEMs and utilities – to provide them with an understanding of:

- The implications of increased RES penetration on the role that energy storage can play in the European electric power sector of the future
- The business case for individual energy storage services and those technologies that are among the most suitable for the individual services
- The actions required to improve the competitiveness of energy storage.

The study was conducted with the assumption of technology neutrality, and its objective was to consider a broad range of storage technologies.

The study was prepared by a coalition of more than 30 energy industry stakeholders. The coalition included storage technology developers (mechanical, electrochemical and chemical storage), utilities, energy companies, research institutions, regulatory authorities and European institutions. The study was financially supported by the FCH JU and was prepared between April 2014 and September 2014.

Scope of the study

The study focuses on the European electric power market in the 2014-2050 horizon. It also investigates other energy markets (gas, heat, hydrogen) to the extent that they are connected with the electric power sector and relevant to the topic of storing electricity produced from renewable sources.

The aim of the study is primarily to assess the suitability of storage to integrate large amounts (of the order of GWh and above) of VRE production into the energy system. The storage services under consideration in the study are: electricity time shift, conversion of electricity to other energy carriers (heat, hydrogen), frequency reserve and T&D investment deferral. “Power storage”-type applications such as power quality/voltage control as well as backup applications are not in the scope of the study.

The study investigates three categories of energy storage technologies in the 2014-2030 horizon[1]:

- P2P storage (lead-acid, Li-ion, flow and NaS batteries, pumped hydro energy storage, compressed air energy storage, liquid air energy storage, and electrolytic hydrogen production and re-electrification)
- Conversion of electricity to heat and storage for later use
- Conversion of electricity to hydrogen for use outside the electric power sector (PEM, alkaline and solid oxide electrolysers).

External sources were consulted for the cost and performance projections of these technologies – no benchmarking was done to verify these cost estimates.

1 The improvements of cost and technical parameters of technologies were only considered until 2030 due to the availability of sources and difficulty of estimating longer-term parameter evolution

Context: EU greenhouse gas emission reduction targets, their impact on the electric power sector and the role of storage

OBJECTIVES FOR THE REDUCTION OF GREENHOUSE GAS EMISSIONS IN THE EU

The European Commission has set challenging targets for the reduction of green-house gas (GHG) emissions in the EU. At present, binding GHG reduction targets are in place for the period up to 2020, and targets for 2030 are being developed. The 2020 and 2030 targets should keep the EU on track to meet its ultimate objective of reducing GHG emissions by at least 80% by 2050.

In March 2007, EU leaders committed Europe to become a highly energy-efficient, low-carbon economy, and in 2009, these objectives were translated into a set of binding legislation – the 2020 climate and energy package.[2] This legislation contains three specific targets:

- Reducing GHG emissions by 20% compared to 1990 levels
- Raising the share of energy from renewable resources to 20% of EU consumption
- Improving EU's energy efficiency by 20%.

At the time of writing this report, the European Commission was working on a policy framework for climate and energy for the period up to 2030. In March 2014, EU leaders agreed to decide on the framework in October at the latest. The central part of the European Commission proposal is a reduction of GHGs by 40%.[3]

The 2050 target of reducing GHG emissions by 80-95% is motivated by the objective to keep climate change below 2°C. This objective was supported by the European Council and the European Parliament and was reconfirmed by the European Council in February 2011.[4]

IMPACT ON THE ELECTRIC POWER SECTOR

The electric power sector in the EU is the largest producer of GHG emissions, accounting for approximately 23% of the EU-27's 2010 total[5] and as such is a key part of the EU effort to reduce GHG emissions. In fact, studies have shown that in order for the EU to achieve an overall 80% GHG reduction by 2050, a nearly complete (90-100%) decarbonisation of electric power production will be required, given the difficulties of reaching 80% decarbonisation in other sectors.[6]

An almost complete decarbonisation of the power sector calls for a sharp change in how electric power is produced in the EU. As of 2009, 51% of EU gross electricity production came from GHG-emitting fossil fuels, followed by 28% from nuclear plants and 20% from renewable sources (RES: hydro, biomass, municipal waste, geothermal, wind and solar).[7]

2 The 2020 climate and energy package; http://ec.europa.eu/clima/policies/package/index_en.htm
3 2030 framework for climate and energy policies
4 Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions: a roadmap for moving to a competitive low-carbon economy in 2050
5 Followed by industry (21%), buildings (17%) and road transportation (17%). Source: McKinsey analysis based on European Environment Agency and IAE data
6 Roadmap 2050: A Practical Guide to a Prosperous Low Carbon Europe, European Climate Foundation, 2011
7 European Environment Agency: Electricity production by fuel (ENER 027) – Assessment, published April 2012

The European Commission has put forward a set of scenarios for the power sector that would be consistent with reaching the decarbonisation target. The share of renewables in electricity generation in these scenarios ranges from 59 to 85% (with the remainder of power demand satisfied by nuclear and CCS-equipped generation).[8] A majority of these renewables production targets will be covered by solar PV as well as on- and offshore wind, whose production is subject to both seasonal as well as hourly weather variability.

The rise in the share of VRE will lead to a set of effects on the power system, the most important of which are:

- Increased variability of residual load[9] (increasing the peak/off-peak spread of the residual load curve and making the curve "steeper")
- More pronounced short-term fluctuations from forecast electricity supply and reduction in system inertia
- Local transmission and distribution grid bottlenecks, as networks may be insufficient to transfer peak VRE production.

As the VRE share in power production increases to very high levels (50% and more), the system flexibility needs, historically driven by variable demand patterns, will become increasingly driven by supply variability. Also, significant amounts of excess renewable energy (on the order of TWh per year) will start to emerge, causing surpluses that are characterised by periods of high power output (GW) far in excess of demand. This could lead to power production from renewables being curtailed. An optimisation of the system would be required to ensure that this renewable energy is utilised rather than curtailed.

8 Energy Roadmap 2050: Impact assessment and scenario analysis

9 Residual load is the difference between electricity demand and VRE production. Positive residual load means that additional electricity has to be supplied from other sources; negative residual load means that the VRE production exceeds electricity demand

FIGURE 2

Residual load patterns (difference between power demand and VRE supply) will be increasingly driven by supply variability

Germany simulation, residual load in GW, 1-month sample

ROLE OF STORAGE IN THE TRANSITION TO A DECARBONISED POWER SECTOR

Given the intermittent nature of wind and solar energy sources, it is clear that the ability to store renewable electricity when it is available in abundance (that is, when the sun is shining and the wind blowing) and use it at a later time is very valuable to the system. The EU's plans to increase the share of renewable energy production have motivated a new wave of interest in energy storage. The European Commission recognises energy storage as an important component in its transition to a decarbonised power sector.

Storage can provide a range of services to the energy sector. In this study, we focus on four broad services that storage can provide to mitigate or leverage the effects of increasing VRE penetration:

- a) Electricity time shift: charging electric power at times of high supply and low demand, storing it and discharging as electricity at times of low supply and high demand. Electricity time shift contributes to the stability of the power grid by reducing the difference in residual demand peaks and troughs. It also allows capturing renewable power that would have to be curtailed, providing it to the grid at a later time.

- b) Conversion to other energy carriers: transforming electric power (preferably at times of high supply and/or low demand) into a different energy carrier, storing this carrier and using it outside the electric power sector. The alternative energy carriers considered in this study are heat and hydrogen. Heat is used for space and water heating in residential and commercial buildings as well as in many industrial processes. The use of hydrogen outside the electric power sector includes mobility applications (e.g., materials-handling vehicles, cars, buses, aircraft, ships), industrial applications (e.g., refineries, chemical industry) or admixture into the natural gas grid.

- c) Provision of frequency reserve and grid services: ensuring the necessary continuous balance between power supply and demand in the electric power grid. To provide the reserve, storage commits capacity to charging when there is an unexpected excess in power supply and to discharging when there is unexpected excess in power demand. Storage can supply products with a different response time and duration of reserve provision (frequency containment reserves, frequency restoration reserves and replacement reserves[10]). Delivery of frequency reserve is also possible in conjunction with the conversion to other carriers. The electrical load used for conversion can be increased or decreased in response to unexpected fluctuation in the balance of supply and demand in the power grid.

- d) Transmission and distribution infrastructure investment deferral: using storage to absorb power that exceeds the capacity of a T&D line or another component and releasing it at a later time when sufficient T&D capacity is available. T&D upgrades usually have high fixed costs (permitting, construction work, etc.), which have to be incurred even when the required additional capacity is limited. Thus, relatively small amounts of storage have the potential to delay (or even avoid) large required investments. In some cases, using storage for a T&D upgrade deferral may be one of the few available options (along with demand side management) due to the very long lead times required for obtaining permits for new T&D construction.

10 Entso-E definitions of individual frequency reserve products, formerly referred to as primary, secondary and tertiary services

Structure of the report and approach

This report is structured in four parts: the first part examines the demand for and value of energy storage for the integration of renewable sources of electricity into the energy system; the second part surveys the various energy storage technologies and the development of their technical as well as economic parameters; the third part considers various business cases for energy storage; and the fourth part reviews the current commercial regulation regarding storage and identifies obstacles to storage commercialisation. In the following paragraphs, we outline the objectives of each of the four parts as well as the approach taken by the study.

PART 1: DEMAND FOR AND VALUE OF STORAGE TO INTEGRATE EXCESS RENEWABLE ELECTRICITY

In Part 1, we assess the value of energy storage and its ability to integrate renewables in electric power. To understand the behaviour and value of storage, we modelled the supply-demand balance of electric power systems and assessed the impact of adding different amounts of storage. We had selected four EU country or region "archetypes" of different sizes and with various characteristics of electric power systems for which we modelled scenarios covering three years (2014, 2030, 2050) and multiple scenarios with respect to the installed renewable capacity as well as the severity of T&D and must-run constraints.

Part 1 answers the following questions:

- How will the value of P2P storage for time shift and integration of renewables evolve in time depending on the renewables penetration and the degree of connectivity?
- What proportion of excess renewable production will P2P storage be able to economically integrate into the system, and to what extent can storage eliminate the need for backup capacity provision from non-renewable sources of electricity?
- What proportion of excess renewable production will conversion to heat and hydrogen be able to economically utilise?

PART 2: SURVEY OF ENERGY STORAGE TECHNOLOGIES AND THEIR TECHNICAL AND COST DEVELOPMENT UNTIL 2030

Part 2 surveys the likely development of technical and cost parameters of selected storage technologies until 2030. The purpose of this part is to provide the reader with an understanding of the suitability of the individual technologies for the provision of the various services. The storage technology parameters on which the coalition aligned in preparation of this part also serve as inputs into other analyses in this report.

To guarantee traceability and transparency of the assumptions, the technologies were assessed using publicly available sources to the greatest extent possible. Input from the coalition was used to select between the sources in case of conflicting data points or where publicly available data was not available. The 2012 ISEA RWTH Technology Overview on Electricity Storage report served as the default source. No benchmarking was done to verify these cost estimates.

Part 2 answers the following questions:

- Which technologies are suitable for the different storage services?
- Which of the technologies have the lowest cost of provision of the different services?
- Which of the technologies are likely to develop the most between 2014 and 2030?

PART 3: STORAGE BUSINESS CASES FOR 2014 AND 2030

In Part 3, we evaluate the opportunity for market-based deployment of energy storage by an independent investor in various stylised situations ("business cases") for the 2014-2030 horizon. We use net present value (NPV) as the main metric for evaluation. Part 3 draws on the work presented in Parts 1 and 2 and focuses on deriving lessons learned from the individual business cases. It also examines the opportunities to use one storage asset for multiple services ("stacking of business cases").

Part 3 answers the following questions:

- Which of the business cases are likely to be profitable by 2030?
- What are the main profitability levers and options to improve the business case?
- What are the regulatory obstacles for storage in the business cases and potential regulatory changes that would improve the business cases?
- What are the opportunities for stacking business cases?

PART 4: ENERGY STORAGE COMMERCIAL REGULATION: OVERVIEW AND RECOMMENDATIONS

Part 4 answers the following questions:

- What regulation is currently in place governing the access of storage to energy markets and its remuneration in this market?
- What examples of advanced storage regulation can be found outside the EU?
- What are the options for removing regulatory obstacles and supporting the development of storage?

Demand for and value of storage to integrate excess renewable electricity

APPROACH TO ESTIMATING THE DEMAND FOR AND VALUE OF STORAGE

This part assesses the value of energy storage and its ability to integrate renewables in electric power systems. To understand the behaviour and value of storage, we modelled the supply-demand balance of electric power systems with various characteristics and assessed the impact of adding different amounts of storage. In particular, the focus was on the change in the supply-demand balance and changes in system costs resulting from storage operation.

To get an understanding of the influence of various factors on the value of storage, we modelled four different country or region archetypes. The archetypes selected by the coalition are:

- Germany, a large Central European country with a high share of intermittent renewables and phasing out of nuclear power by 2022
- Spain, a large Southern European country with a high share of intermittent renewables
- Sweden, a medium-sized Nordic country with a high share of nuclear and hydro power
- Island of Crete (Greece), a Mediterranean island with a high share of intermittent renewables.

Certain implications of introducing storage to a country are best illustrated by the example of an individual country. In such cases, we consistently use the example of Germany – Europe's largest power consumer.

For each archetype[11] we model the electric power system at three points in time: 2014, 2030 and 2050.

For each of the future years (2030 and 2050), we considered two scenarios for the development of the European energy sector with widely different RES penetrations. Throughout the study, we took electricity demand, generation and installed generation capacity from the scenarios as exogenous input:

- The "reference scenario" is based on the European Commission's "Trends to 2050: Reference scenario 2013." The scenario projects the development of the EU energy system under current trends and includes all binding targets on GHG emission reduction and energy efficiency improvement adopted as of spring 2012. In the reference scenario, 50% of electricity in 2050 is generated from renewable sources, two thirds of which (or 35% of total production) come from VRE. By 2050, CO2 emissions from electricity generation will fall to roughly 500 Mt, which constitutes a 70% decline compared to 2000, but falls short of the required 90-100% reduction.

The "high-RES" scenario is based on the European Commission's Energy Roadmap 2050 and is one of the six decarbonisation scenarios presented in the document. Each of the decarbonisation scenarios achieves the 2050 targets through a different mix of RES, nuclear and CCS-equipped fossil plants. The high-RES scenario has the largest share of RES in power generation (85% in 2050) and, thus, presents both the biggest challenge for integrating renewables and the biggest opportunity for storage.

11 Excluding Crete, for which future generation fleet development scenarios are not available

The importance of T&D infrastructure build-up

One of the greatest uncertainties in the development of the electric power sector is the speed and scale of the T&D infrastructure build-up. The capacity of T&D infrastructure has significant implications for the role of storage in the system and for the amount of excess electricity generated by VRE. As a result, the coalition believes that the topic deserves special attention:

- Because intermittent renewables are rarely producing at full capacity, the required installed capacity for any given amount of produced energy is higher than in the case of conventional plants for which the legacy T&D infrastructure was designed. This creates a need to increase the capacity of European T&D networks if the power generated while the VREs are producing close to maximum capacity is to be absorbed into the grid.
- If the T&D capacity is not sufficient to absorb the power into the grid, the output of the renewable sources has to be curtailed. Curtailment can happen at various levels of the T&D grid (from the local distribution grid to the national transmission grid). Curtailment is already happening locally in Europe, even though on a small scale only. In Germany, for example, 0.33% of the renewables production was curtailed in 2012[12], and in North-West Scotland, 1.4% of large (over 10 MW) wind farm output was curtailed between October 2012 and March 2013.[13]
- While the scenarios developed by the European Commission are based on the assumption that the T&D investments required to integrate the renewable production will be undertaken, there is significant uncertainty regarding the feasibility and costs of T&D build-up. Europe is densely populated and there are considerable obstacles (both physical and administrative) to the construction of the new T&D infrastructure.
- An additional limitation regarding the system's capacity to absorb VRE-generated energy is grid stability currently provided by conventional synchronous generators (mainly fossil, nuclear and hydro power plants). At any point, the system needs reliable and controllable reserves to keep the balance of supply and demand as well as a minimum amount of mechanical inertia to dampen grid frequency variations. This results in a "must-run" constraint where a certain minimum share of demand has to be provided by conventional generation at each point in time. An example of a system running up against its must-run constraint is the Irish grid, which has set the maximum share of power from wind and PV ("System Non-Synchronous Penetration") relative to demand at 50%. [14]Wind and solar production in excess of this threshold is curtailed even if the local T&D capacity is sufficient to absorb it.

12 Bundesnetzagentur Monitoringbericht 2013
13 NationalGrid Winter Outlook 2013/2014
14 EirGrid 2012 Curtailment report

To test the impact of T&D and must-run constraints on the value of storage, we present the following cases:

- In the base case, we treat each country as an island (no international interconnections) and assume that there are no internal T&D constraints in the country as well as no must-run constraint. That is, curtailment only occurs if the total power production exceeds the country's total demand in at some point in time.
- The "T&D constraints" case is based on the assumption that there is no development in T&D networks and that the highest historically observed VRE absorption is the maximum that the grid can accommodate. In other words, curtailment occurs whenever VRE production exceeds the maximum historically observed VRE grid in-feed. In practice, this limits the maximum share of wind and PV power to about 50% of demand in most of the cases and is therefore also a good approximation of the must-run constraint. This case results in the highest curtailment and is the most favourable case for storage.
- In the "Copperplate Europe" case, we assess the impact of treating the three large modelled country archetypes (Spain, Germany, and Sweden) as a single system with no T&D constraints and no must-run constraints. This approximates the case when substantial T&D capacity is built up. The aggregate VRE production then becomes more even and easier to integrate into the system (less installed capacity is required for any given produced amount of energy, as the sun shines and the wind blows at different times in different parts of Europe – the production profile becomes smoother and the amount of curtailment decreases). This is the least favourable case for storage.

In Part 1, we take a societal-benefits point of view and consider the total benefit of storage to the system compared to its costs. The benefits of the system are equal to the value of the fuel and CO2 emissions saved as a result of adding storage into the system. Where the amount of storage is sufficient to reduce the amount of thermal backup capacity required, the fixed costs of this capacity are included in the benefits. Against this, we evaluate the annualised storage capital and operating costs with EUR 65 per installed kW per year considered the minimum achievable cost.[15]

For the focus years, the following key commodity and CO2 prices are assumed:

Commodity	2013	2030	2050
Gas (EUR/MWh)	27	36	36
Coal (USD/tonne)	83	140	170
CO2 (EUR/tonne)	5	35	100

15 EUR 65 per installed kW per year is based on the costs of PHES. PHES is the most cost-effective 2014 technology and will likely be among the most competitive technologies in 2030 as well. The EUR 65 per installed kW per year rests on the following assumptions: 1:8 power to energy ratio, EUR 500/kW + EUR 5/kWh capex, EUR 3.9/kW fixed opex, EUR 8/MWh variable opex, 25% discharge utilisation, 8% cost of capital and 55 years lifetime

All EUR figures used are in real 2014 EUR. Throughout the report, we are assuming costs of capital of 8%, which corresponds to assets with high systematic risk exposure.

Throughout Part 1, the effects of adding storage with 1:8 power-to-energy ratio and 80% round-trip efficiency are modelled. This approximates the parameters of pumped hydro storage – the only currently widespread energy time-shift technology and the one with the lowest cost. These assumptions are later relaxed when the ability of storage to reduce the required amount of backup capacity is considered.

Two different dispatch policies for storage are modelled:

- Daily time-shift mode: the storage is discharging for eight hours per day with the highest residual load and is charging during those eight hours per day with the lowest residual load.
- Excess renewables integration mode: the storage is charging whenever curtailment occurs (either due to excess supply or due to T&D and must-run constraints) and discharging as soon as the curtailment stops.

In the current system, the daily time-shift mode is more profitable, as the amount of curtailment is low and the daily demand patterns ensure high utilisation of the technology. As the installed capacity of renewables increases, the amount of curtailment will rise. As VRE penetration increases, the excess renewables integration mode becomes more profitable while at the same time traditional daily demand patterns are disrupted, reducing profitability of the daily time-shift mode. In considering the benefits of storage, the dispatch policy for which the benefit is larger in the given scenario is used.

Estimating the demand for and the value of storage is a complex task that carries a high level of uncertainty – the value of storage depends on multiple parameters, such as composition of the electricity generation fleet, fuel and CO2 prices, local T&D capacity and must-run constraints, demand patterns, regulation governing storage as well as others.

The main limitations of the modelling approach in Part 1 are:

- Dispatch of backup generation is based on plant marginal cost only. In particular, no start and stop costs are considered for backup generation. This has two implications: the model may underestimate intra-day electricity price variations and does not generate negative electricity prices in the wholesale market.
- The T&D network topology is not modelled explicitly. T&D and must-run constraints are modelled at country level by imposing limits on the amount of VRE energy that can be fed into the grid at country level. Thus, the model does not enable the analysis of the optimal location of storage in the grid.
- The model calculates the benefits of storage from the societal point of view and does not consider how the benefits are distributed to individual stakeholders or what contractual arrangements would be required for the benefits to materialise.

Key finding 1

In the high-renewables scenario (60% and more VRE penetration by 2050), there will be economic potential for very large amounts (up to 10 times the currently installed capacity, or about 400 GW in the EU) of P2P storage for the integration of intermittent renewables. Storage demand in the 2030 horizon will depend on country-specific characteristics, in particular on the level of interconnectivity.

Results for Germany are presented first with a focus on explaining the drivers of storage value, after which results for other countries are discussed.

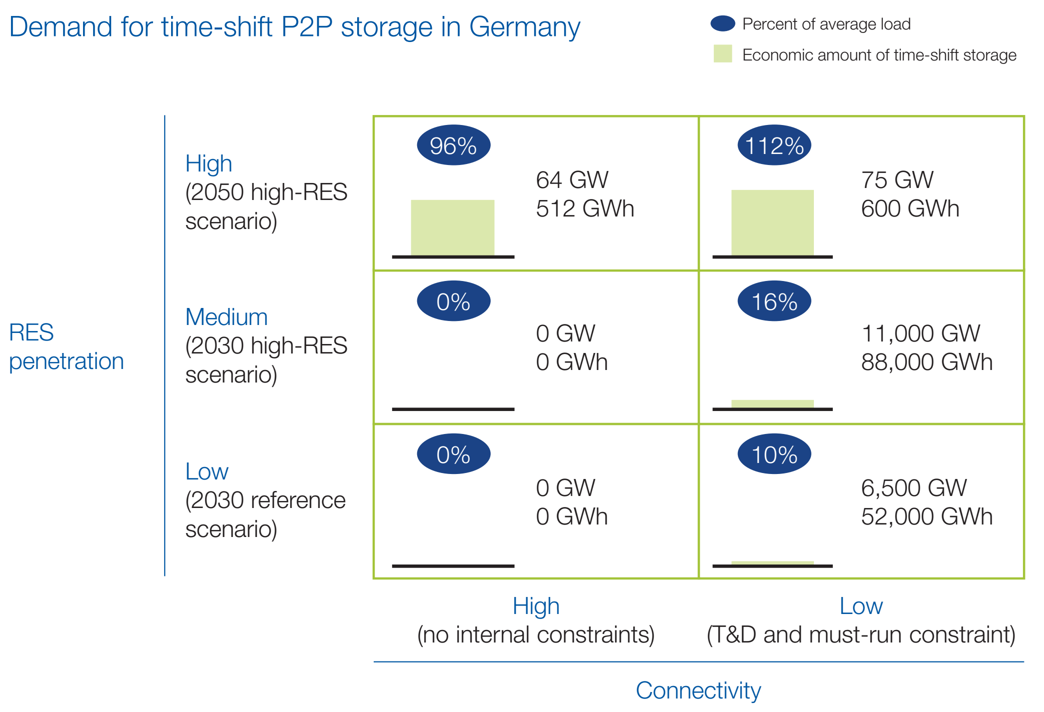
In the 2030 horizon, we estimate the installed capacity of time-shift storage in Germany for which the societal benefits at least equal greenfield costs[16] to be between 0 and 11,000 MW. The main driver of the storage value is the degree of connectivity (T&D and must-run constraints).

Given the current German installed pumped hydro capacity of roughly 7,000 MW,[17] there could be an opportunity for an increase of up to 4,000 MW (57%) in time-shift capacity by 2030 and a roughly tenfold increase in time-shift capacity by 2050. Due to location and environmental constraints, the increase will be only partially covered by pumped hydro storage, creating opportunities for new technologies (e.g., compressed air, liquid air or various batteries, hydrogen energy storage).

16 Costs including capex charge. Storage for which capex has already been fully paid would only need to cover its operating costs

17 German PHES generation capacity was 6,777 MW and 39 GWh in 2011, EURELECTRIC, "Hydro in Europe: Powering Renewables", 2011

FIGURE 3



Note: 80% efficient storage with value of EUR 65 per installed kW and 1:8 power-to-energy ratio

In none of the 2030 high-connectivity scenarios does storage for time shift justify its greenfield costs. In the daily time-shift mode, the peak/off-peak difference in fuel costs and CO2 emissions is insufficient to cover storage costs. At the same time, there is very little excess renewable energy, meaning that storage integrating this excess only reaches very low utilisation.

At low connectivity (with T&D and must-run constraints), the amount of excess energy in 2030 increases sharply, and significant amounts of storage are now able to fully cover their greenfield costs by integrating the excess energy into the grid and reducing the amount of required fossil backup.

By 2050, the system will produce significant amounts of excess energy in the high-RES scenario, even without T&D and must-run constraints. In addition, with an assumed CO2 price increase to EUR 100/tonne (from EUR 35/tonne in 2030), benefits of each MWh of excess renewable energy integrated into the system increase sharply. Introducing the T&D and must-run constraints in the 2050 high-RES scenario increases the economically viable storage capacity only moderately, since availability of excess energy is not a severe constraint in the 2050 high-connectivity case.

Key finding 2

Even with a tenfold increase in installed P2P storage capacities, a significant amount of backup non-renewable generation and large installed non-RES power plant capacity will still be required for prolonged periods (several days) with low wind and sunshine. At the same time, in the high-RES scenario, there will still be periods with large amounts of excess renewable energy that cannot be used in the electric power system directly or through P2P storage.

Due to the time mismatch between supply and demand, considerable non-renewable generation is required for the times when there is little sunshine and wind speed is too low or too high, even though the total amount of RES energy produced exceeds the total electricity demand. Furthermore, the residual demand profile will be very steep at times, requiring a fast backup capacity with high ramping speeds.

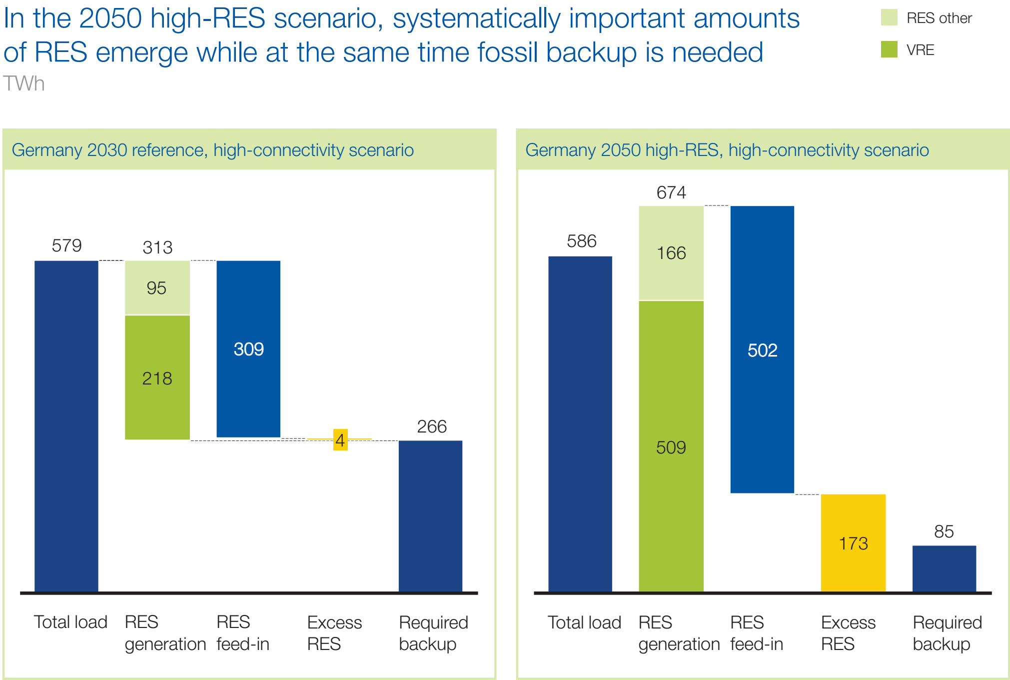
As the VRE-installed capacity exceeds the maximum electricity demand, there will be an increasing amount of electricity produced at times when there is no immediate demand. This “excess” RES generation can be stored for later use in the electric power sector, converted to another energy carrier for use outside the electric power sector (heat, hydrogen) or has to be curtailed.

The amount of excess RES generation increases when T&D and must-run constraints are introduced, but even in the high-connectivity case it eventually becomes substantial. Only small amounts of excess RES generation would emerge in the German 2030 reference case. However, in the 2050 high-RES case, the excess RES energy would amount to 173 TWh (nearly 30% of the total electricity demand), while the required non-RES generation would amount to 85 TWh (15% of the total electricity demand).

FIGURE 4

In the 2050 high-RES scenario, systematically important amounts of RES emerge while at the same time fossil backup is needed

TWh

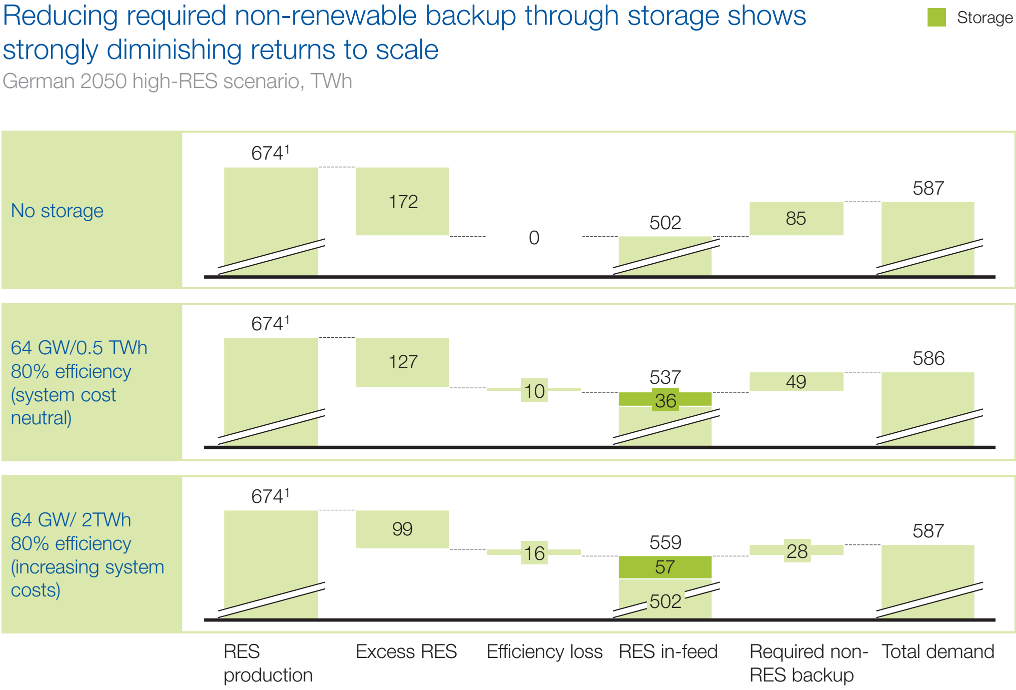


Considering the maximum economic amount of storage determined for the 2050 high-RES scenario (64,000 MW/512,000 MWh), we find that this amount of storage reduces the required fossil backup from 85 TWh to 49 TWh, i.e., a decline in non-RES backup from 15% to about 8%. This translates into a fossil fuel and CO2 cost reduction of EUR 4.2 billion per year, which equals the annual capital charge and operating costs of the storage. Achieving a two-thirds reduction in fossil backup would require a fourfold increase in storage energy capacity to approximately 2 TWh, illustrating the diminishing returns to scale when deploying increasing amounts of storage.

FIGURE 5

Reducing required non-renewable backup through storage shows strongly diminishing returns to scale

German 2050 high-RES scenario, TWh



1 Of which 508 TWh VRE, 166 TWh other

To evaluate the economics of using P2P storage in order to reduce non-RES generation further, we consider the costs and benefits of reducing non-RES generation to 5% of total demand, or 28 TWh per year in the German 2050 high-RES scenario.

At the assumed fuel and CO2 costs, the benefit of reducing non-renewable generation from 85 TWh to 28 TWh amounts to EUR 6.6 billion per year. In addition, the fixed costs of fossil backup plants are up to EUR 5 billion per year[18] and additional savings may come from reducing the required capacity. However, as shown later, even large amounts of storage are not likely to reduce the required backup power capacity substantially, and a large part of the non-renewable "backup" plant capex will be a sunk cost by the time sufficient storage is installed. Therefore, the storage capacity benefit is likely to only account for a fraction of the EUR 5 billion fixed backup costs.

To assess the costs of reducing backup to 28 TWh, we consider four technologies suitable for energy-intensive application: pumped hydro storage, compressed air storage (mechanical storage), flow batteries (electrochemical storage) and conversion of excess RES electricity to hydrogen, storing it in high-capacity storage (e.g., salt cavern or other gas storage facility) and re-electrifying it by using a dedicated CCGT power plant (chemical storage).

18 Greenfield costs of 64,000 MW of CCGT backup at EUR 667/kW capex, 20 years lifetime, 8% WACC and 17 EUR/kW annual opex; Source: IEA

For this analysis, we use an optimised power-to-energy ratio for each of the three alternative technologies (1:72 for flow batteries and A-CAES, 1:336 (2-week) high-capacity hydrogen storage) while keeping the 1:8 ratio for pumped hydro storage.

As the technology survey has only been conducted until 2030, we are using low-range (most optimistic) 2030 costs for reference. Additional T&D costs and hydrogen transportation costs are not included. In this assessment, the following technology parameters are used:

FIGURE 6

Parameters used for evaluation of storage costs

		Storage capex costs		Opex			
Technology	Efficiency	EUR/kW	EUR/kWh	Fixed opex EUR/kW	Fixed opex EUR/kWh	Variable opex kWh	Lifetime (years)
Adiabatic compressed air storage	65%	700	40	21	–	0.003	30
Flow-Vanadium battery	73%	600	70	15	2	–	20
Electrolyser + salt cavern + CCGT	40%	1,000	0.2	20	–	0.010	15
Pumped hydro energy storage	80%	500	5	4	–	0.008	55

SOURCE: ISEA RWTH 2012; coalition input

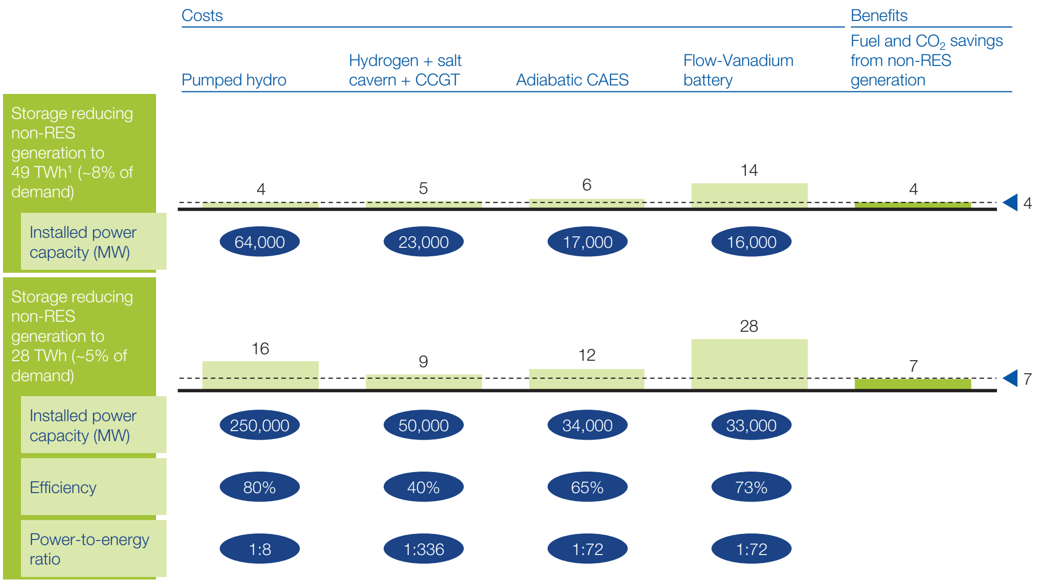
The calculations are simplified and intended to provide order-of-magnitude examples of the costs and benefits of storage. They are not intended to represent the exact costs of the individual options or imply geographical feasibility of installing the assumed amounts of storage.

As we can observe, the costs of storage exceed the system savings by a factor of about 1.3 to 2 for chemical and mechanical storage and by a factor of 4 in the case of electrochemical storage. For chemical and mechanical storage, the benefits of reducing non-RES backup would catch up with storage costs in excess of EUR 200/tonne of CO2 – significantly higher than EUR 100/tonne of CO2 assumed for 2050.

FIGURE 7

From a certain point, costs of reducing required non-RES generation through storage increase faster than the benefits

Germany 2050 high-RES scenario, annual storage costs and benefits, EUR billions



1 49 TWh chosen because it is the largest decrease in non-RES generation for which the benefits equal the costs of storage

Based on the above analysis, we can draw the following conclusions about using storage to integrate excess renewables and to reduce the required fossil backup:

- Very large amounts of storage would be required to significantly reduce the required fossil backup even in the case of high RES penetration. For Germany, about 50 times the current pumped hydro capacity would be needed to reduce the required non-RES generation to one third compared to the case without storage. This is because long (order of days) periods of excess RES production alternate with periods of insufficient RES output.
- Given the scale involved, it is likely that nearly all of the technologies concerned will start running into constraints regarding locations (suitable high-capacity hydrogen storage, elevations for pumped hydro, etc.), and their capex costs will start to rise as they are placed in ever less favourable locations. This implies that a mix of technologies would be used with mechanical and chemical storage as the main contenders for a large share of the capacity.
- There are strong diminishing returns to the scale of storage – doubling the storage energy capacity less than doubles the amount of excess RES integrated into the grid. From a societal-benefit point of view, it is optimal not to integrate all of the excess electricity back into the power grid and retain some amount of non-renewable "backup" generation in the system. The remaining excess electricity would stay available for a conversion to other carriers.

As noted in the previous section, the electric power system will require a significant amount of non-RES energy (as measured by MWh), even if large storage capacity is available. In this section, we examine to what extent storage can reduce the required amount of fossil backup power installed capacity (as measured by MW).

To understand the impact of storage on required backup capacity, we simulate two operating modes of the 64 GW/512 GWh storage in the German 2050 high-RES scenario – the first minimising the required non-RES energy produced (and the attendant CO2 emissions) and the second aimed at minimising the required non-RES generation backup capacity.

In the case of minimising the required fossil energy, storage reduces the required fossil production from 85 to 49 TWh, but has no impact on the required backup capacity. The maximum backup capacity needed during unfavourable sun and wind conditions remains at 67.2 GW.

It could be possible to somewhat reduce the required backup capacity by switching the storage into a short-term peak-shaving and valley-filling mode between the longer-term excess RES integration cycles. This would require significant forecasting ability or risk damaging of the economics of the storage (e.g., storage would charge expensive fossil energy in anticipation of a further peak which would not materialise) and was not modelled in this study.

When a storage asset is deployed to minimise the required backup capacity, its ability to integrate renewables is severely limited. In this mode, the storage needs to be ready and sufficiently charged for the case when the backup requirement exceeds a given threshold. This limits the time during which the storage is discharging. Our hypothetical 64 GW/512 GWh of storage would be able to reduce the amount of required backup capacity in the system from 67.2 to 44 GW. The price for this is a reduction in total annual storage discharge from 36 TWh to just 3 TWh, as the storage asset cannot discharge for most of the year to be able to provide the necessary capacity when needed.

Comparing the economics, the storage that maximises the integration of renewables brings an annual benefit of EUR 4.1 billion in saved CO2 costs, whereas the storage that minimises the required backup capacity brings an annual benefit of EUR 1.8 billion, EUR 1.5 billion of which comes from avoided capacity-fixed costs.

When storage is maximising the integration of renewables, the utilisation of non-RES backup is reduced and its profitability deteriorates. While this does not influence the calculation of societal benefits, new mechanisms (e.g., capacity markets) may be required to ensure that the backup capacity is provided.

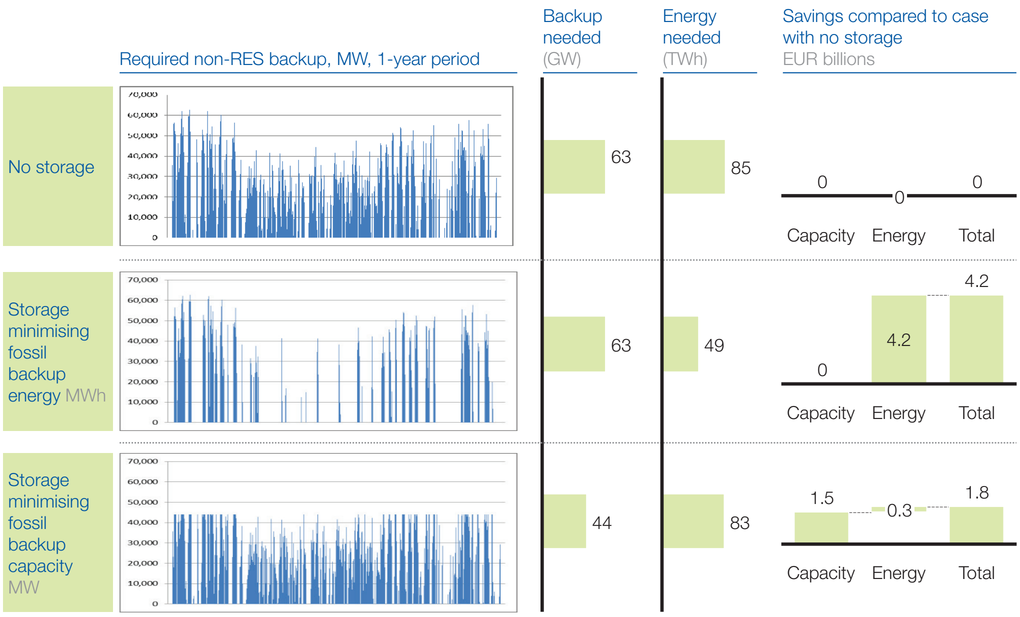
Significant reduction in the backup capacity would only be possible with very large (on the order of 50 TWh and more) energy storage capacity. This storage will be charged with excess renewable energy throughout the year, but it will be discharged only when required to displace the use of fossil fuel for backup power. This would require energy capacity costs of the technology to be extremely low.

Of the technologies surveyed, only chemical storage (notably hydrogen storage) could potentially achieve acceptable economics at this scale.

FIGURE 8

Storage can reduce the required backup generation capacity; however, only at the expense of utilisation

German 2050 high-RES scenario, 64 GW/512 GWh of storage



Apart from a purely economic consideration, using storage for minimising the required backup capacity would result in a less secure energy system, as an unexpectedly long period of low VRE production would exhaust the ability of the storage to cope with residual demand peaks. The system would also produce much more CO2 than in the case when storage is used to minimise the required backup energy.

Based on the results provided by the simulation model, we conclude that even at large installed storage capacities, it will be quite challenging to significantly reduce the amount of installed fossil backup generation. This is a direct result of finite energy capacity of storage – if it is to fulfil this role, it has to remain charged and mostly inactive to be able to cope with contingencies. This in turn reduces its utilisation and damages its economics.

Key finding 3

Demand for storage differs significantly between countries with different generation profiles. In particular, large reservoir hydro capacity such as in Sweden is a carbon-free option to integrate renewables and eliminate the need for further storage. By contrast, non-interconnected islands, or markets that behave as such, are a suitable early market for storage driven by emerging renewables curtailment and very high fossil generation costs. Depending on the island characteristics, there already may be economic demand for storage reaching tens of percent of installed power generation capacity.

In this section, we review the demand for storage for electricity time shift and integration of renewables into the grid for the remaining country or regional archetypes: Sweden, Spain and the island of Crete (Greece).

In Sweden, we foresee no economic demand for storage for electricity time shift and excess RES integration, even in the high-RES scenarios. This is a direct result of the composition of Sweden's generation mix with nuclear and reservoir hydro accounting for nearly all electricity production in the country, achieving an almost zero-carbon electricity generation mix.

Storage for electricity time shift and excess RES integration in Sweden is made redundant by the country's reservoir hydro energy capacity, which amounts to 33.7 TWh (900 times the total pumped hydro storage capacity of Germany).[19] This extremely large and fast-acting natural storage capacity allows Sweden to fully balance its renewables portfolio.

Because balancing the portfolio through reservoir hydro is free of CO2 emissions, Sweden does not need to install VRE capacity in excess of its maximum load to achieve a high-RES share in generation. Reservoir hydro thus also practically eliminates the excess energy phenomenon.

These results are confirmed by EURELECTRIC: "In Norway and Sweden the building of pumped storage power plants has so far not been economically profitable, since these countries have many conventional storage hydropower plants, which effectively take care of all power system service needs."[20] and by the observation that the only Swedish-pumped hydro plant at Juktan was re-configured to become a regular hydro power station, as its operation in pumped hydro was deemed unprofitable.[21]

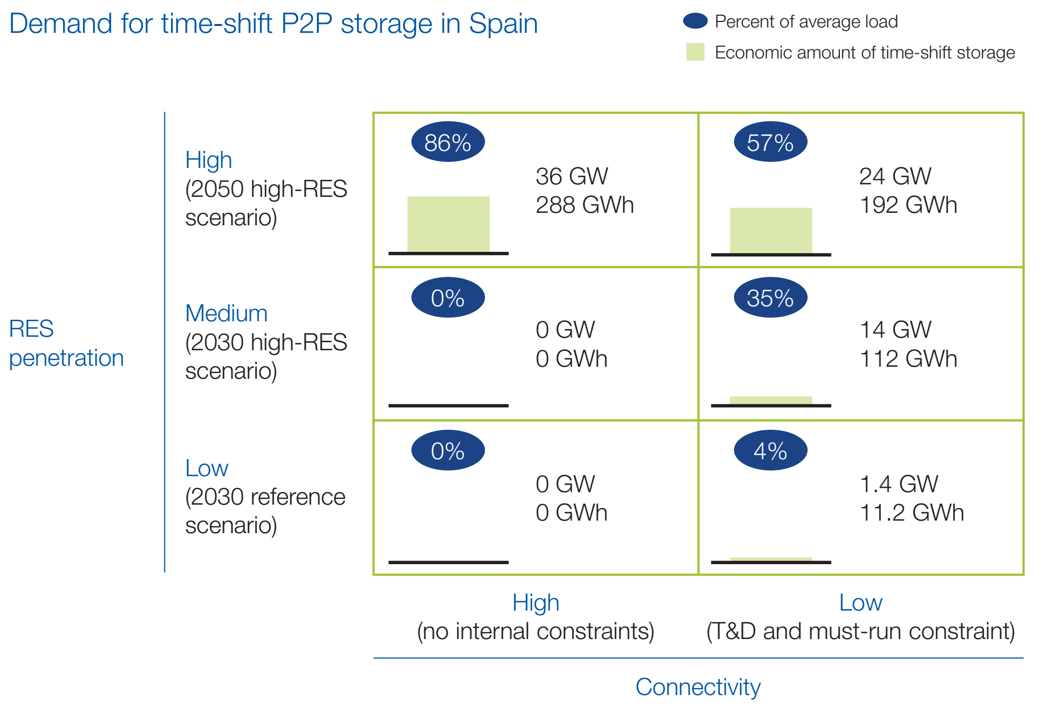
The demand patterns of energy storage in Spain are very similar to those observed in Germany. The 2030 high-RES, low-connectivity scenario implies an economic potential of 14,000 MW of time-shift capacity, an increase of more than 100% compared to the approximately 6,000 MW currently installed PHS. In the 2050 scenarios, storage demand increases by a factor of 4 to 6 compared to the current state. Note that the assumed T&D constraint is so severe for the 2050 high-RES case that the economic amount of storage decreases compared to the high-connectivity case. The very frequent instances of excess electricity in this case limit the time during which storage can be discharging and thus reduce its utilisation.

19 Generation capacity of Swedish reservoir hydro amounts to 16,203 MW, or about equal to the total average load. Svenski Energi, The Electricity year 2012

20 Hydro in Europe: Powering Renewables, EURELECTRIC, 2011

21 Vattenfall website

FIGURE 9



Note: 80% efficient storage with value of EUR 65 per installed kW and 1:8 power-to-energy ratio

Crete is an example of an island system already achieving the limits of renewables feed-in with an estimated 44 GWh (approximately 1.5% of total electricity demand) of curtailed wind energy in 2013.[22] The curtailment occurred as a result of T&D and system stability constraints, which are limiting the maximum wind power output at around 35% of load. At the same time, the generation capacity consists mostly of heavy fuel oil and diesel-powered units, with very high marginal costs (up to EUR 300/MWh). Therefore, this example unites two characteristics favourable for storage:

- Availability of curtailed energy
- High cost of fossil fuels that would be replaced by energy discharged from storage.

Model results confirm this with 60 MW/480 MWh of storage or 18% of average load currently being the economic amount of storage, assuming the annual cost of storage is at EUR 65 per installed kW for storage asset with 1:8 power-to-energy ratio. This amount of storage would integrate about 25 GWh of excess energy into the system. Crete is the only of the four country archetypes where greenfield storage capacity would be currently economically interesting.

22 Source: HEDNO

It should be noted that within the EU there are many islands (in the Mediterranean and Atlantic) and island member states (UK, Ireland and potentially Iceland) that approach this archetype because they have no or only limited interconnections to the European mainland. Similar dynamics could also be observed in mainland regions with limited interconnection capacity.

While more specific research would be required especially with respect to the costs of storage construction and local constraints and conditions, the case demonstrates that island systems with high fossil fuel costs and a large share of renewables are the optimal early market for storage and could play an important role in demonstrating commercial viability of storage while serving as stepping stones for further technology development.

As seen in the results so far, the level of interconnectivity plays an important role for the amount of storage that can be economically deployed in the system. In this context, we also test an example of extreme interconnectivity ("copperplate Europe"), where electric power is able to flow freely across three of the country archetypes studied previously – Sweden, Spain and Germany. In addition, this combined archetype benefits from the wide geographical spread of the countries considered, which means that the wind and solar production patterns are less correlated and they complement each other.

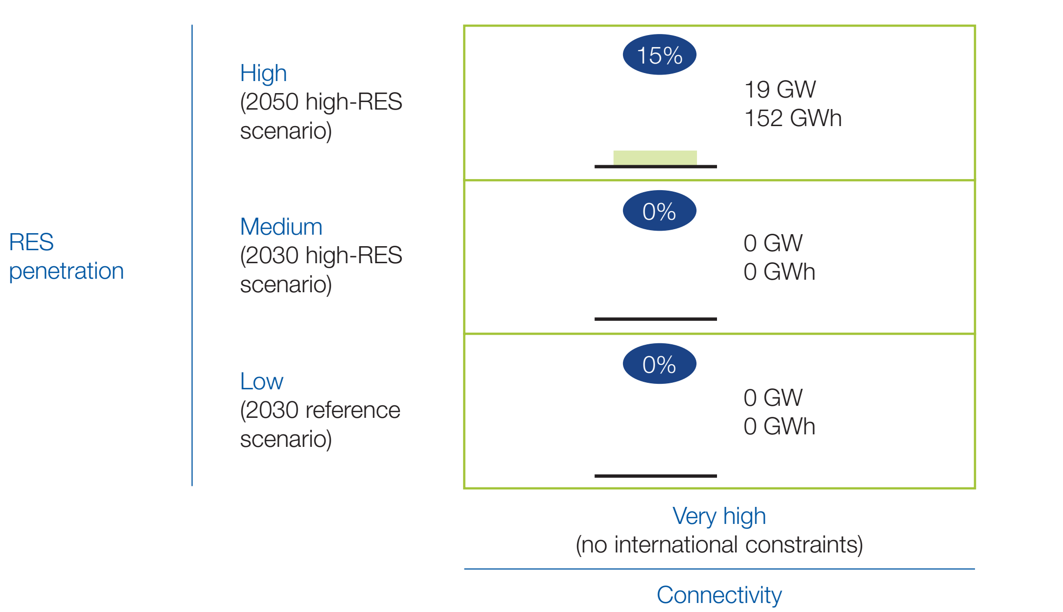
The level of interconnection assumed in this case is likely not to be realistic, since it would require transporting many tens of GWs across the long distances of the combined archetype (compared to, for example, the 2013 German export capacity of about 9.2 GW).[23] However, this hypothetical example points to a significant potential of European hydro reservoirs to assist the integration of high penetration of VRE. The feasibility and costs of this should be further investigated.

In line with expectations, such a degree of interconnectivity would have a very negative impact on the required amount of storage. The combined greenfield demand for the three countries would fall from 100 GW to about 19 GW – a decrease of 81%. A major driver of the decrease is the ability of the large reservoir hydro production (mainly in Sweden, to a lesser extent in Spain) to balance the variable renewables and reduce the required non-RES generation backup. Storage utilisation falls, as it has fewer opportunities to discharge and replace non-RES generation, and its economics deteriorate.

23 Bundesministerium für Wirtschaft und Energie, May 2014: http://www.bmwi.de/BMWi/Redaktion/PDF/PR/Parlamentarische-Anfragen/18-1181,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf

FIGURE 10

Demand for timeshift P2P storage – Sweden, Spain and Germany combined



Note: 80% efficient storage with value of EUR 65 per installed kW and 1:8 power-to-energy ratio

Additional uncertainties exist over the 2030-2050 horizon that could significantly reduce the demand for storage. These uncertainties stem from a combination of technology improvements and technology-driven changes in consumer behaviour:

- Improvements in wind and PV solar technology, which would enable higher production during times of low wind or sun. This would result in higher direct feed-in of VRE into the grid at a given installed capacity and would lead to a reduction in the amount of required VRE over-instalment and, thus, in the amount of excess energy available for storage and conversion to other carriers.
- Increase in the flexibility and larger penetration of biomass plants, resulting in a reduction of the required VRE-installed capacity and providing for a carbon-free balancing of VRE. The impact of biomass in such a case would be comparable to that of large hydro reservoirs.
- Large penetration of smart grids and controllable loads (including EVs), enabling significant increase in demand at times of high VRE generation, which would flatten the residual demand curve and reduce the amount of excess energy available for storage. However, only part of the electricity demand is flexible and can be delayed, and an even smaller fraction of electricity demand is flexible over horizons exceeding one day. This limits the impact of the demand side management.
- Mass adoption of further renewable energy technologies (e.g., tidal, geothermal), providing more predictable energy supply, reducing the need for VRE, flattening the residual demand curve and reducing the amount of excess energy.

CONVERSION OF ELECTRICITY TO OTHER CARRIERS

As we have seen previously, even with very high installed P2P storage capacities, the electric power system will still generate large amounts of excess renewable electricity in the high-RES scenario in the 2050 horizon. Given the very low marginal costs of wind and PV production, the question arises how to productively utilise this excess energy and prevent it from being curtailed. A potential solution is the conversion of this energy to other carriers and its use outside the electric power sector.

In this study, we consider two alternative energy carriers: heat and hydrogen. The possibility to store heat means that electrified heating can be a source of flexibility in the system (producing heat during high VRE production and reducing demand during low VRE production). Similarly, electrolytic production of hydrogen is a controllable electricity load that can utilise renewable energy, which would otherwise be curtailed, and turn it into hydrogen, a universal energy carrier with a wide range of uses.

CONTRIBUTION OF CONVERSION TO HEAT TO INTEGRATION OF VRE

Key finding 4

Conversion of electricity to heat and heat storage is a proven and relatively low-cost option for providing flexibility to the power system. As increasing VRE penetration will drive higher volatility in electricity prices, the business case for and penetration of heat storage will improve further. Conversion to heat and heat storage will be able to utilise a part of the excess renewable energy and reduce the required non-RES generation. However, the potential of conversion to heat to integrate VRE is limited by the share of electricity demand used for heating and its seasonality.

Heating is a major part of the EU energy consumption, accounting for roughly 45% of the total EU final energy demand compared with 35% share of transport and 20% share of electricity. [24]Main components of the heating demand are space heating and cooling, hot water and industrial processes.

Currently, most of the heat in the EU is generated from gas or in CHP (co-generation of heat and power) with electric heating only playing a minor role.[25]

Heat can be stored for various periods of time (e.g., in water, molten salt or phase change materials). The ability to store heat means that electrified heating becomes a flexible load – the consumption of electricity for heating can occur at a different time than the consumption of the heat itself. This differentiates electrified heating from most other sources of electricity demand and opens the possibility to use conversion of electricity to heat together with storage of heat to use the excess electricity as well as to reduce electricity demand at times with low VRE generation.

24 Source: Enerdata Odyssee, IEA

25 EU residential and tertiary heating demand was mostly covered by gas (46%) and oil (20%) with CHP accounting for 10% and electricity for 9%, Enerdata Odyssee

Decarbonisation of heating

Reduction of heating-related CO2 emissions can be achieved through a combination of increasing efficiency of end use (e.g., by improving building insulation), increasing the efficiency of heat production or changing the fuel mix used to generate heat.

To the extent that the electric grid is sufficiently decarbonised, electrification of heating is one of the options to reduce heating CO2 emissions. Other possibilities include increasing the share of heating produced by highly efficient non-RES CHP plants or biomass CHP plants. Heating patterns and options for heating system decarbonisation differ significantly between EU countries.

An example of a pathway for EU heating decarbonisation by 2050 is provided by the European Climate Fund Roadmap 2050 study. Residential and tertiary heating demand decreases by 45% (through end-use efficiency increase), with 90% of the remaining heating transferred to heat pumps. With heat pumps assumed to consume 25% of the energy of the source they replace, this leads to a total decrease in residential and tertiary energy consumption for heating of about 80%. In contrast, only 10% of the 2050 industrial energy demand would be transferred to heat pumps with the remaining industry heating demand still provided by gas. In total, heating would account for about 20% of the 2050 electricity consumption.

The European Commission's high-RES scenario used in this study does not provide a detailed breakdown of electric demand used for heating. However, all electricity demand for heating is already included in the total EU electricity consumption of 3,370 TWh. Triangulating the electricity demand components based on the information provided by the scenario, heating accounts for 15-25% of the electricity demand in the scenario.

Continuing our example of Germany's 2050 high-RES scenario, we demonstrate the impact of heat storage on the amount of excess energy and required non-RES backup. In particular, we consider two scenarios – a system with the ability to store the equivalent of one-day heat demand and system able to store the equivalent of seven-day heating demand, both in the situation where heating demand accounts for 20% of the total electricity consumption.

To assess the impact of heat storage, we implemented a simple heat storage function in the power market model with the following functionality:

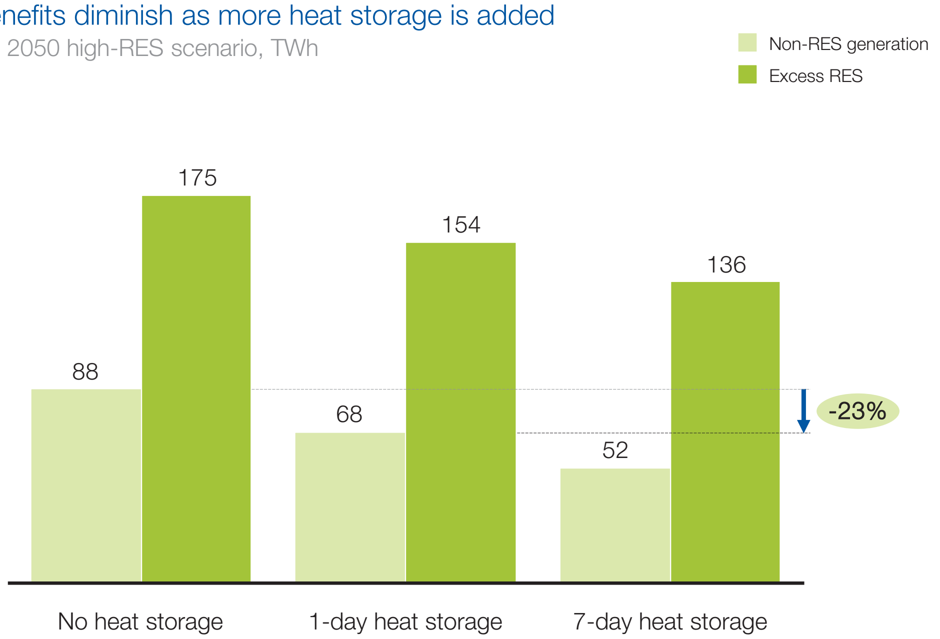
- Heat storage stores energy when there is excess electricity up to the point when the assumed (one-day or seven-day) heat storage capacity is reached.
- Heat storage discharges heat whenever there is demand for heating that is covered by non-RES generation. The required non-RES generation is reduced by an equivalent amount.
- For this analysis, we are using an electricity demand profile taking into account the amount of heating electrification. We also disregard heat storage losses, as they do not have a significant impact on the overall conclusions.

Being able to store heat for one day results in an almost 25% decrease in the required non-RES generation – a significant contribution. The amount of heat storage required for this is substantial – almost 3 TWh of heat storage capacity.

FIGURE 11

1-day heat storage appreciably reduces required non-RES generation, but benefits diminish as more heat storage is added

German 2050 high-RES scenario, TWh



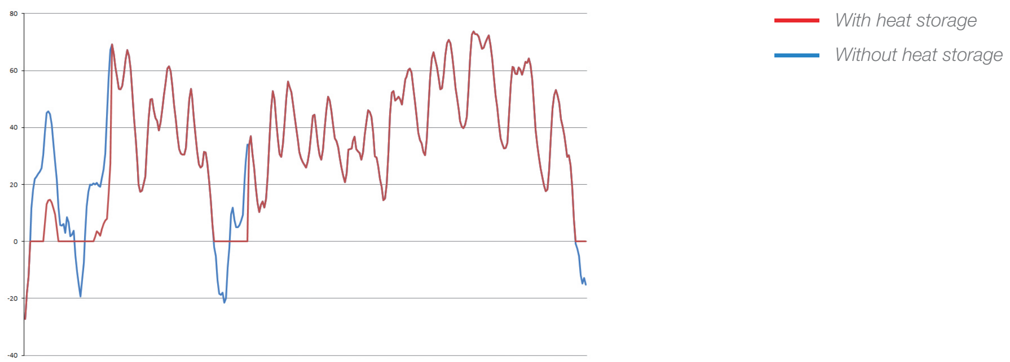
Short-term storage of heat is a proven technology which is already deployed in several countries across Europe (e.g., there is an established market for electric storage heaters in the UK and Germany, smaller hot water tanks are installed in France to shift demand between day and night, and large steel tanks are used in district heating networks in Denmark). With rising volatility of energy prices due to alternating periods of excess electricity and increasingly expensive non-RES generation, the deployment of heat storage is set to rise and will contribute to the integration of renewables.

On the contrary, wide deployment of storage covering multiple days' worth of heat demand at system level is unlikely for three reasons:

- Diminishing benefits of storage: utilisation and benefit per unit of storage decreases as larger storage capacity is added. Seven-day storage would support a capex of EUR 2/kWh at the maximum – out of reach of decentralised heat storage.
- Physical size: seven-day hot water storage would require an estimated 6 m3 per person – which is not feasible for decentralised heat production and storage.
- Storage losses: as the period for which heat is stored increases, so do the losses of heat. Household-size hot water tanks lose about 10% of heat every day, and only large storage (hundreds of m3) is able to achieve acceptable losses (single-digit percentage per week). However, other heat storage technologies (phase change, chemical) can have significantly lower heat losses. Multi-day heat storage could thus only be feasible in central heating systems (e.g., district heating), which are only installed in some geographies and could require further substantial infrastructure investments.

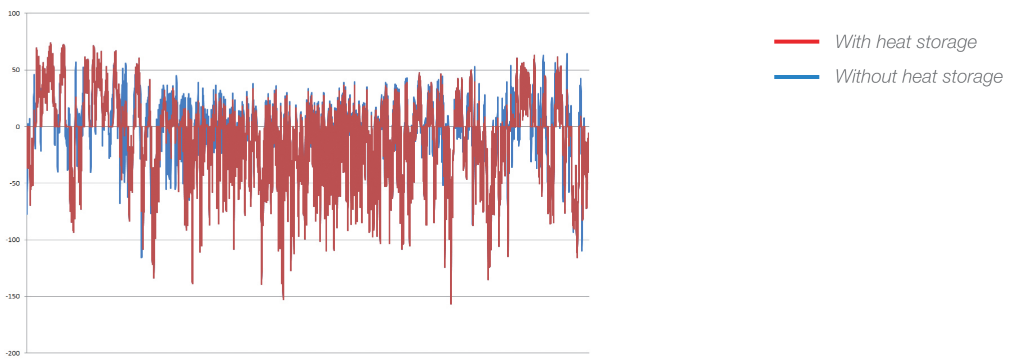
Dynamics of heat storage is similar to that of P2P storage – its ability to utilise excess energy and reduce required non-RES generation is therefore limited by its energy capacity. When curtailment is occurring over several days, the heat storage reaches its capacity and cannot continue charging while at the same time discharging is not valuable.

FIGURE 12: RESIDUAL LOAD – 2 WEEKS IN JANUARY, GW



An additional feature of heat storage is its strong seasonality. As the chart below shows, heat storage makes almost no difference to the residual load profile during the summer months.

FIGURE 13: RESIDUAL LOAD – 1 YEAR, GW



CONTRIBUTION TO INTEGRATION OF VRE THROUGH CONVERSION TO HYDROGEN

Key finding 5
Conversion of electricity to hydrogen through water electrolysis and use of this hydrogen in the gas grid (P2G), mobility or industry can productively utilise nearly all excess renewable energy in the high-renewables scenario, contributing to the decarbonisation of these sectors. European potential for installed electrolyser capacity in 2050 high-RES scenarios would be in the hundreds of GWs. This requires that there either is local demand for hydrogen at the production site or that the hydrogen can be economically transported to a demand centre.

Hydrogen is one of the most universal energy carriers. Currently it is mainly used in industry (with EU annual production of approximately 6 million tonnes,[26] corresponding to energy content of about 200 TWh). It can additionally be used for P2P storage, for mobility or as a substitute for natural gas (either through admixture of small amounts of hydrogen into the gas grid or by replacing natural gas with synthetic gas obtained through hydrogen methanation).

Hydrogen is considered to be a promising energy carrier (fuel cells and hydrogen are included among the European Commission's strategic energy technologies) and significant R&D progress has been made over the past years. In the following text, we consider the economic potential of hydrogen to the contribution to RES integration.

Similar to the demand for storage, we can estimate the demand for electrolyser capacity and the amount of hydrogen produced in 2030 and 2050 by comparing the societal benefits with the costs of adding electrolyser capacity to the system. We assume that the electrolyser is only operating at times when electricity would otherwise be curtailed.

As a proxy for societal value of electrolyser output, we assume that each kg of hydrogen produced is worth EUR 2. This corresponds to the predicted 2050 plant gate value of hydrogen for industrial use.[27]

The cost of including an electrolyser in the system is set at EUR 60 per installed kW per year, corresponding to the 2030 costs of large (10 MW) alkaline electrolyser capex and opex costs.[28] The operation of the electrolyser is assumed to use only excess energy.

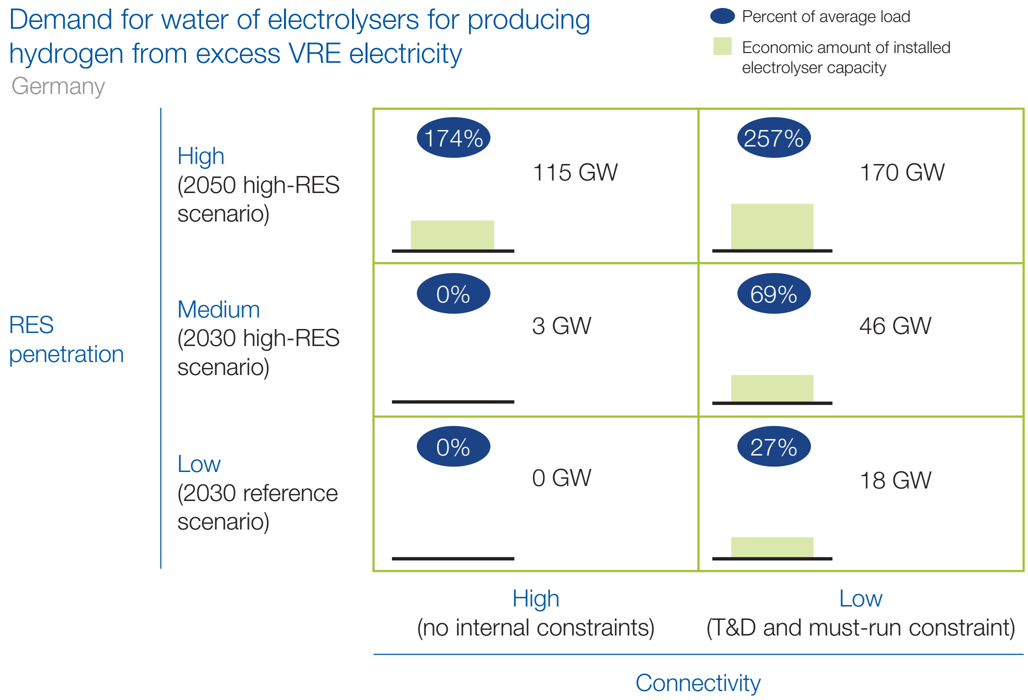
Finally, we assume that no P2P time shift or heating storage utilises the excess energy and that the hydrogen can be used at the location of the electrolyser or that it can be economically transported to a demand centre.

26 Strategic Energy Technologies Information System: http://setis.ec.europa.eu/technologies/Hydrogen-and-fuel cells/info
27 Plant gate electrolytic hydrogen value for both 2025 and 2050 according to HyUnder study (2014)
28 Assumes EUR 370/kW capex, 8% WACC, annual opex at 1.2% of total capex and 10 years lifetime, FCH JU 2014

FIGURE 14

Demand for water of electrolysers for producing hydrogen from excess VRE electricity

Germany



Note: Assumes value of EUR 2/kg at the production site

in the results we observe similar patterns as in the case of storage – there will be very little economic electrolyser capacity in 2030 without T&D constraints, as there is very little curtailed energy for the electrolysers to utilise. In the case of low connectivity, an economically viable electrolyser capacity becomes substantial as early as in 2030.

In 2050, the large amount of excess energy would further increase the economically viable capacity of electrolysers to the extent that it would exceed the average load of the electricity grid. This is not a contradiction, as the maximum VRE production would exceed the average load by a factor of up to 3. Hydrogen demand at the assumed price of EUR 2/kg would be the limiting factor for electrolyser deployment at this point. The electrolysers would produce 3.5 million tonnes of hydrogen in the high-connectivity case and 5 million tonnes of hydrogen in the low-connectivity case while utilising nearly all of the excess renewable energy.

FIGURE 15

Low energy capacity is a limiting factor for utilisation

German high-RES scenario; March 2050

1 1:8 power-to-energy example, 20 GW power capacity

A comparison of the economic amount of electrolysers with demand for P2P storage (Figure 14) shows that the optimal installed eletrolyser capacity is higher despite similar cost per installed capacity (EUR 65/kW/year for storage and EUR 60/kW/year for electrolyser). This is because the utilisation (and benefit) of P2P storage is frequently limited by its energy capacity – the storage is often full and unable to charge, whereas the electrolyser keeps producing (see Figure 14). This is based on the assumption that the produced hydrogen is continuously transported from the production site or that low-cost salt cavern storage is available. If these assumptions are not met, on-site buffer storage of the produced hydrogen would be required, which would increase the cost and reduce the economic electrolyser capacity.

Part 2:

Overview of energy storage technologies and their technical and cost development 2014-2030

APPROACH TO THE OVERVIEW OF STORAGE TECHNOLOGIES

We collected storage technology parameters that determine the applicability of each technology to the various storage services (size of storage and maximum storage time, voltage level, ramp rate, response time, physical size), its cost of usage and deployment (efficiency, lifetime, power, energy-specific capex and operating costs).

To guarantee traceability and transparency of the assumptions, the technologies were assessed using publicly available sources to the greatest extent possible. Input from the coalition was used to select a source in case of conflicting data points or where publicly available data was not available. The 2012 ISEA RWTH Technology Over-view on Electricity Storage report was selected as the default source. No benchmarking was done to validate these cost estimates.

To understand the economics of different P2P storage technologies for different services, the study uses the levelised costs of electricity (LCoE) metric in a set of stylised use cases, representing different operating modes of storage.

The economics of conversion of electricity to hydrogen is studied based on a comparison with the costs of steam methane reforming, the current incumbent technology.

The range of technology and cost parameters reported in literature and by coalition members is very wide, even with today's parameters are concerned. Outliers in both directions may be observed in practice, especially in the case of emerging technologies.

The study focuses on more mature technologies where a greater basis for predicting the development of the technology and cost exists. A disruptive technology development (of both the focus and other technologies) could result in significantly lower technology costs than those assumed in this report.

SUITABILITY OF TECHNOLOGIES FOR VARIOUS STORAGE SERVICES

Storage technologies have a wide range of technical and cost parameters that make them more or less suitable for the provision of various storage services. Examples of important parameters governing the technology fit with the services include:

- Response time and ramp rate: indicating how fast the storage can be activated and changes the rate at which it is charging and discharging. These are important characteristics for the provision of frequency reserve, which requires the capability to react quickly to the regulation signal.
- Maximum storage time at rated capacity: expressing for how long the storage can typically deliver its full power. This determines whether the technology is a better fit for services requiring the delivery of energy over a longer period ("energy-intensive") or for delivering energy in short bursts ("power-intensive").
- Physical size and location constraints: providing clear constraints on the possibility of using storage in a given location. An example of such constraints might be the availability of salt caverns for hydrogen storage or suitable terrain for the pumped hydro storage.

- Cycle life: indicating how many times the storage can be fully charged and discharged before its end of life. Technologies with higher cycle life are more suitable for services requiring frequent use. Furthermore, for some technologies cycle life depends on the depth of discharge.

While the applicability of a technology will always be location-specific to some extent, it is possible to make general observations about the suitability of the focus technologies for the three P2P storage services under consideration (frequency reserve, time shift, T&D upgrade deferral):

- Batteries (lead-acid, lithium, flow, NaS) can typically react and change their rate of charge or discharge very fast. This makes them well suited for the provision of frequency reserve. Location flexibility, scalability and transportability make batteries also a good fit for T&D upgrade deferral. Maximum storage time at rated capacity for batteries is typically on the order of hours, making them suitable for daily time shift but less suited for time shift over longer periods. Flow batteries with their scalable energy capacity are an important exception in this respect.

FIGURE 16

P2P storage technologies – key parameters and costs

Low (optimistic) range of cost estimates

	Parameter	Storage round-trip efficiency	Storage capex/kW	Storage capex/ kWh	Storage opex fixed	Storage opex fixed	Storage opex variable	Cycle lifetime	Storage lifetime
	Unit	Percent	EUR/kW	EUR/kWh	EUR/kW	EUR/kWh	EUR/MWh	Thousand	Years
Li-ion	2013	85	0	375	10	0	2	3	12.5
	2030	88	0	200	10	0	2	6.5	12.5
NaS	2013	78	150	500	35	0	0	7.5	12.5
	2030	85	35	80	35	0	0	7.5	12.5
Flow-V	2013	68	1000	300	25	7.5	0	10	20
	2030	73	600	70	15	2	0	15	20
PHES	2013	78	500	5	4	0	8	>50	55
	2030	78	500	5	4	0	8	>50	55
CAES-A	2013	65	1,000	40	30	0	0	20	35
	2030	65	700	40	21	0	0	20	35
CAES-D	2013	65	500	50	15	0	~30	20	35
	2030	65	400	40	12	0	~30	20	35
Lead-acid	2013	78	150	100	6	0	0	1	10
	2030	81	105	70	6	0	0	3	10
LAES-A	2013	57	1,500	50	38	0	0	20	30
	2030	67	1,200	40	30	0	0	20	30
LAES-A	2013	36	1,850	0.2	37	0	10	10	15
	2030	40	1,000	0.2	20	0	10	10	15

Costs include electronics and civil works but exclude grid connection.

SOURCE: ISEA RWTH 2012: Technology overview on electricity storage; coalition input

- Mechanical storage technologies in focus (pumped hydro, compressed air, liquid air) can usually react fast enough to provide secondary, tertiary and in some cases also primary frequency reserve services. Unlike batteries, these technologies are built on “utility” scale with typical rated power capacity in the tens or hundreds of MW. Their maximum storage time is limited by the space in which the storage medium (water or air) can be stored and can reach hours or days. This makes mechanical storage suitable for daily time shift as well as longer-term time-shift applications.[29]
- Water electrolysers producing hydrogen can change their load quickly. Thus, they can provide negative frequency reserve by increasing output. If they are operating, they can also provide positive reserve power by reducing output. A combination of electrolyser with hydrogen storage and a CCGT power plant or fuel cell can also provide time shift. Very large potential storage capacity (especially in the case of underground storage) also makes hydrogen production and storage applicable for longer duration time-shift applications. Outside the power sector, hydrogen can be used for mobility, in the gas grid or in the industry.

COST COMPARISON OF TECHNOLOGIES

To compare the cost of different technologies for selected services, we use the LCoE metric. LCoE takes into account all capex and opex costs of storage and puts them in relation with the amount of energy produced by storage to calculate the “all-in” costs per MWh produced, considering the time value of money and the energy production. The formula for LCoE is:

FIGURE 17

The LCoE compares the unit cost of different technologies over their technical lifetime

$$\text{LCoE} = \frac{\sum_t \left((\text{Investment}_t + \text{O\&M}_t + \text{Fuel}_t + \text{Carbon}_t + \text{Decommissioning}_t) \cdot (1+r)^{-t}\right)}{\sum_t \left(\text{Electricity}_t \cdot (1+r)^{-t}\right)}$$

“Fuel” in the case of storage is the cost of electricity charged into the storage. For the calculations in this section, we assume the electricity price to be zero. This enables us to isolate the costs associated with shifting each MWh in time (function of storage) from the costs of producing it.[30] This methodology favours technologies with low efficiency, as the cost of losses increases with the electricity price.

29 This is not a general feature of mechanical storage as a class but rather pertains only to the three focus technologies. A counterexample is the flywheel – a mechanical storage technology with very short maximum storage time, suited for power-intensive applications

30 In literature, this metric is sometimes called “Levelised Cost of Flexibility”

To test the cost performance of focus technologies for power-intensive applications, we set up the following use case simulating the hypothetical delivery of frequency reserve requiring 5 MW and 5 MWh of storage, elapsing one full cycle every two hours (4,380 cycles per year). Pumped hydro storage is currently the leading option for this application, while batteries are at present not competitive:

- Pumped hydro storage (PHES) is currently the most attractive technology and achieves LCoE in the range of EUR 18-28/MWh. LCoE of CAES and LAES starts at around EUR 30/MWh. Battery technologies are currently not competitive for this use with their LCoE starting at around EUR 140.
- Based on the optimistic range of cost forecasts, Li-ion batteries can largely catch up with the mechanical storage for power-intensive applications by 2030. Lithium-based batteries are expected to be the cheapest battery technology with LCoE starting at EUR 38/MWh, followed by flow-V batteries with LCoE at EUR 55/MWh. LCoE of PHES will remain unchanged at EUR 18-28/MWh, whereas the minimum LCoE of CAES and LAES will fall towards the EUR 20/MWh mark.

We determine the LCoE of technologies for energy-intensive applications based on a stylised daily time-shift example, where storage with a 1:8 power-to-energy ratio is fully charged and discharged once a day every day of the year. Note that this results in lower utilisation than the power-intensive application example.

Also in this case, pumped hydro storage is currently the front-runner, while batteries are at the end of the pack. Pumped hydro storage (PHES) is the most attractive technology, with LCoE in the range of EUR 24-42 EUR/MWh. CAES and LAES have LCoE in the range of EUR 50. Of all battery technologies, LCoE are currently much higher – in excess of EUR 100/MWh for lead-acid, Li-ion, NaS and flow-V batteries.

In 2030, PHES will remain the most cost-effective technology for energy applications with EUR 24-42/MWh, while costs of battery technologies will catch up with liquid air and compressed air. In particular, LCoE of lead-acid, NaS and flow-V batteries may start at or below EUR 50/MWh.

Finally, we also consider the case of long-term energy storage, represented by a case with a 1:2,000 power-to-energy ratio, which, for simplicity, is discharged once per year. The battery technologies considered (Li-ion, NaS, lead and flow-V) would likely not be eligible for such use, and their high energy capacity cost as well as the low use case number of cycles in combination with high storage capex would lead to LCoE in excess of EUR 9,000/MWh, even at the low end of the costs expected for 2030. Mechanical storage could in the most optimistic case achieve LCoE on the order of EUR 450/MWh, which would be severely limited by the availability of locations for reservoirs of this size and would exceed EUR 3,000/MWh for the other mechanical storage technologies (CAES, LAES). The most cost-effective technology for long-term energy storage is creating hydrogen through water electrolysis, storing it in a salt cavern and re-electrifying by burning it in a turbine. In this case, the LCoE are on the order of EUR 140/MWh. In case of hydrogen storage, the low cost of energy storage capacity compensates for the low round-trip efficiency.

FIGURE 18

Overview of technology LCoEs for power- and energy-intensive applications

EUR/MWh

	Power-intensive application example (1 h of storage)				Energy-intensive application example (8 hrs of storage)				Long-term storage (2,000 hrs of storage)
	2013		2030		2013		2030		2030
	Low	High	Low	High	Low	High	Low	High	Low
Li-ion	138	573	38	106	181	754	76	218	1,000s
NaS	n/a	n/a	n/a	n/a	196	269	42	68	1,000s
Flow-V	155	238	57	97	148	239	50	96	1,000s
Lead	211	379	59	110	114	262	39	98	1,000s
CAES-A	27	n/a	19	n/a	49	n/a	37	n/a	1,000s
LAES-A	40	82	32	66	71	166	57	133	1,000s
PHES	18	28	18	28	24	42	24	42	>400
P2P H_2	Electrolyser and CCPP with salt cavern storage considered for P2P H_2 – suitable for longer-term storage								140

SOURCE: LCoE model; ISEA RWTH 2012: Technology overview on electricity storage; coalition input

DRIVERS OF TECHNOLOGY AND COST DEVELOPMENT

As seen above, the three technology families for P2P storage (electrochemical, chemical and mechanical) have different potentials for improvement between 2014 and 2030:

- Battery cost and performance is expected to improve significantly towards 2030, the trend being particularly pronounced for less mature technologies such as Li-ion, NaS and flow batteries. New battery chemistries will improve efficiency and cycle life, and large-scale industrialisation will decrease the manufacturing costs, especially for technologies applicable in various fields and exploiting large-scale economies (Li-ion batteries).
- Given the maturity of the technology, pumped hydro storage will not improve its cost and performance significantly; compressed air and liquid air technologies will gain from improvement in cost on the system level, whereas the component-driven performance improvement will be more limited due to the maturity of the majority of the components used.
- Technology improvements and cost reductions concerning chemical storage (conversion to hydrogen) will come from the development in electrolyser, fuel cells and thermal reconversion (OCGT, CCGT) technologies, whereas storage relies on mature technologies with limited improvement potential.

At current wholesale electricity prices, the minimum cost of electrolytic hydrogen production is about EUR 2.6/kg if no grid fees and other levies are applied, but rising to EUR 5.9/kg if full industrial customer grid fees and levies are applied.

FIGURE 19

Water electrolyser – key parameters and costs

		Alkaline		PEM		Solid oxide
Parameter	Unit	2013	2030	2013	2030	2030
Electrolyser capex[1]	EUR/kW	650[2] -1,200	370 -800	1,860-2,320	250 -1,270	625[2]
Electrolyser opex	Percent of capex annually	2-5	2-5	2-5	2-5	2[2]
Efficiency	kW/kg H_2	50-78	48-63	50-83	44-53	36-43[2]

1 Including power supply, system control and gas drying
2 Coalition member input

SOURCE: FCHJU; coalition member input

The technological and cost development of electrolyser technologies will act to reduce the cost of electrolytic hydrogen. However, increasing average grid electricity costs will act in the opposite direction. PEM and alkaline electrolysers will be able to achieve costs of EUR 2.0-2.7/kg without fees and levies, rising over EUR 5.5 with full industrial consumer fees and levies applied. The currently less mature solid oxide technology may potentially be able to achieve similar costs in the EUR 2.5 range without fees and levies.

Storage business cases for 2014 and 2030

APPROACH TO STORAGE BUSINESS CASES

In this part, we present the results of modelling a set of stylised business cases for storage. We first review the overall outcomes, summarise the lessons learned from individual business cases, including required changes in regulation to make the business cases viable, and finally evaluate the benefits of stacking business cases.

The business cases are evaluated for 2014 and 2030 from a point of view of an independent investor. To assess whether there is a positive business case, the study used the profitability index (PI). The index is defined as discounted cash flows over the life of the asset (excluding initial capex) divided by the initial capex. A PI greater than 1 is equivalent to a positive NPV of the project. The business cases are market-based and, in particular, do not include any launch support or subsidies.

Since the profitability of a particular business case depends on many parameters, we conducted a sensitivity analysis to identify those levers that can have the biggest contribution towards improving the economics of the business case. Base case parameters were selected to approximate current EU conditions. We also analysed what changes in the market structure would improve the business case for storage. The purpose of the business cases is not to present specific profitability values, but to understand the basic dynamics and economics of the main possible storage uses.

Our calculation of the business cases is based on the current market structure and regulation. Some of the analysed business cases would not be feasible under the current regulation – where this is the case, the market structure assumptions are made clear beforehand.

For the business case, we used the low (optimistic) capex range for both 2014 and 2030. Only selected technologies (based on technology fit) were evaluated for each of the business cases.
The coalition has selected seven business cases that were analysed in detail:

1. P2P storage providing grid-level daily time shift
2. P2P storage providing secondary frequency reserve
3. P2P storage providing T&D upgrade deferral
4. P2P storage used to reduce wind generation curtailment and to integrate the excess power into the grid
5. P2P storage used for short-term firming of wind generation output
6. P2P storage coupled with home PV to minimise the amount of power purchased from the grid.
7. Electrolyser converting electricity to hydrogen for use outside of the power sector

Key finding 6

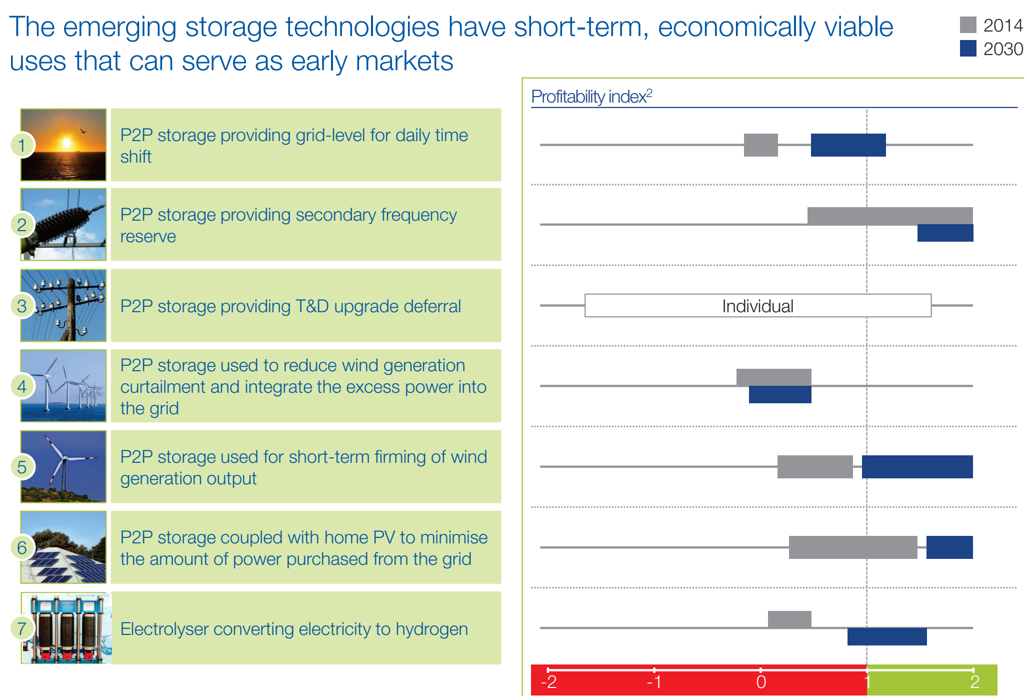
Proven and emerging storage technologies have economically viable uses in the short run and can contribute to meeting the flexibility needs of the power system while creating value for society. These applications include time shift in island systems, deferral of T&D upgrades, provision of frequency reserve and home storage coupled with PV. Accessing these markets will require a review of the regulation that currently prevents storage from participating in the market on a level playing field with the other flexibility options. The overall impact of storage with large energy capacities substituting non-RES generation in VRE-based energy systems needs to be assessed in more depth in further studies.

When using the low range of cost estimates, two of the business cases are already positive today. Large-scale mechanical storage technologies (pumped hydro, compressed air, liquid air) show a positive business case for the provision of frequency reserve, whereas lead-acid batteries show a positive business case for the integration of home PV production (with Li-ion batteries close to profitability). In addition, T&D deferral is highly location-specific and can result in a positive business case if the deferred expense is large enough. For the remaining business cases and technologies, the capital costs are still too high compared to the achievable benefits given the characteristics of the current energy system in the EU.

Due to the combination of increased market volatility (higher RES penetration and increased CO2 costs) and technology cost reduction, most of the business cases can become positive before 2030. However, for many this would require a change in market structure or regulation. The regulatory implications are discussed for each case and also summarised in Part 4, which is specifically dealing with regulation.

Stacking business cases (using one storage asset for multiple services at the same time) has the potential to improve the business case for storage. However, since some services (frequency reserve, T&D deferral) require availability of the entire storage capacity for the whole period for which they are offered, we only identified several generally applicable examples where stacking is a viable option. Further stacking combinations may be viable based on the local market and regulatory conditions as well as the compatibility of the required storage charging and discharging profiles.

FIGURE 20



1 Assuming current network fees, WACC of 8%, electricity price development according to archetype modelling

2 NPV of project cashflows, excluding initial outlay divided by initial outlay. Profitability index greater than 1 denotes positive NPV, range based on values for different storage technologies

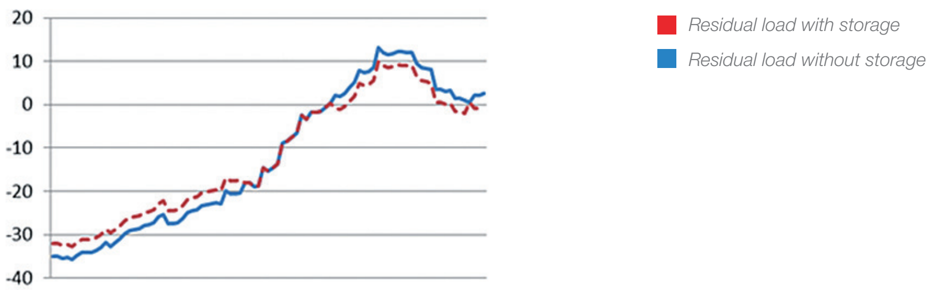
1) P2P STORAGE PROVIDING GRID-LEVEL DAILY TIME SHIFT

Business case description:

- Purchasing power off-peak at wholesale price and selling it into the wholesale market during peak hours on a daily basis
- Storage discharges eight hours of the day with the highest residual demand and charges in required number of hours (based on efficiency) with the lowest residual demand and with perfect foresight.

Operating mode illustration:

FIGURE 21 – BUSINESS CASE 1 ILLUSTRATION: RESIDUAL LOAD (IN GW) WITH AND WITHOUT STORAGE[31]



Key parameters:

- Frequency: approximately one cycle per day (storage doesn't discharge if residual load is below zero).
- Base case size: 100 MW/800 MWh
- Technologies considered: PHES, CAES, LAES, Li-ion batteries, NaS batteries, lead-acid batteries
- 2014 average wholesale charge/discharge spread: EUR 24/MWh[32]
- 2030 average wholesale charge/discharge spread: EUR 44/MWh[32]
- No network fees, taxes and levies.

Business case findings:

- In general the business case is less attractive, as the charge-discharge spread is low compared to the LCoE the storage technologies are able to achieve.
- The business case deteriorates as new storage is added and the peak/off-peak difference is arbitraged away.
- The exemption of storage from consumption tax as well as other fees and levies is an important condition for the existence of a positive business case in both 2014 and 2030.

31 Larger storage than 100 MW used in the illustration
32 Based on German high-RES archetype modelling and storage behaviour, including adjustment to increase intra-day volatility

- Storage operating in this mode shaves the residual demand peaks and thus contributes to system adequacy. If a capacity payment mechanism were introduced, there would be a case for including daily time-shift storage in the scheme. This would improve the economics of the business case.

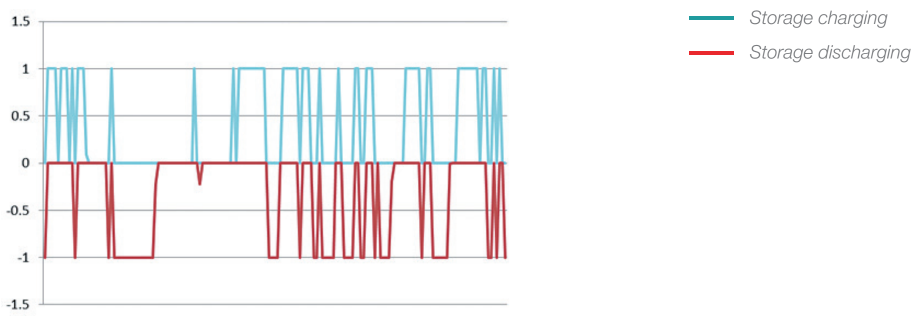
2) P2P STORAGE PROVIDING SECONDARY FREQUENCY RESERVE

Business case description:

- Storage provides both positive and negative secondary frequency reserve and is remunerated for both provision of capacity and delivered energy
- The business case is based on the assumption that storage with 1:4 power-to-energy ratio would be eligible to provide secondary services. Regulation of ancillary services is country-specific, but in general this would require a change in regulation governing the access of storage to the market and the length of the period for which provision of the service has to be guaranteed.

Operating mode illustration:

FIGURE 22 – BUSINESS CASE 2 ILLUSTRATION:
STORAGE CHARGING AND DISCHARGING CYCLES OVER THE PERIOD OF 2 DAYS, MW



Key parameters:

- Business case calculated based on actual German secondary reserve demand during one week in 2014
- Storage power capacity: 5 MW
- Power-to-energy ratio: 1:4, storage energy capacity: 20 MWh
- Energy payment: EUR 50/MWh for positive reserve, EUR 0/MWh for negative reserve
- Weekly average capacity payment: EUR 2,000/MW (payment for both positive and negative reserve capacity)
- Technologies considered: PHES, CAES, LAES, Li-ion, NaS, lead-acid batteries.

Business case findings:

- The business case is already positive in 2014 for large-scale mechanical technologies (pumped hydro, compressed air, liquid air) and will become positive for all of the considered battery technologies before 2030.
- Positive business case results for mechanical technology installations (PHES, CAES, LAES) does not imply that dedicated units for provision of frequency reserves would be built in the current market for two reasons
  - Under the current regulation, greater energy capacity than four hours would be required for participation in the market. Alternatively, only part of the power capacity could be used for provision of frequency reserve (with the remaining part of power capacity participating in the wholesale market and ensuring that the storage is always able to provide the frequency reserve) – this is the currently observed operating model.
  - The scale of the business case is very low compared to the typical size of the mechanical technology installations, and dedicated units of this size likely could not be constructed at the low range of costs.
- Provision of frequency reserves has several favourable characteristics for storage – a high number of cycles translate into good utilisation, the payment per delivered MWh exceeds the arbitrage spread achievable in the wholesale market and, in addition, there is a substantial payment for the availability of capacity.
- This business case highlights the need for regulatory clarification of the rules under which storage can participate in the secondary services market – especially with regard to the maximum required continuous duration of the provision of the service and the minimum intervals between subsequent activations of the service.

3) P2P STORAGE PROVIDING T&D UPGRADE DEFERRAL

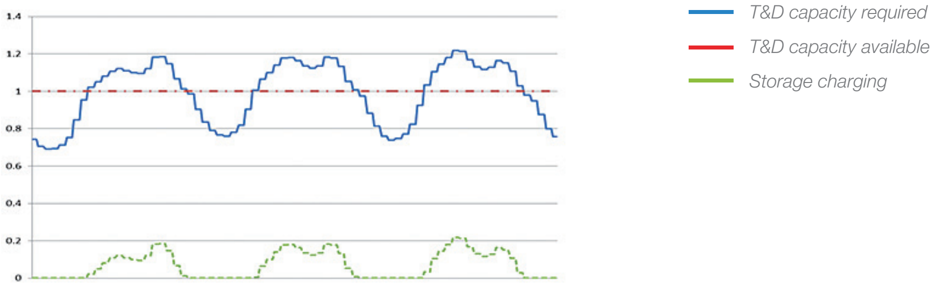
Business case description:

- Storage is used to delay a necessary upgrade of T&D infrastructure that would be required due to power loads higher than the T&D capacity. Typically, storage would be used to absorb power at times when it would exceed the capacity of an adjacent T&D line or substation. The electricity would be released at a later time when sufficient T&D capacity becomes available.

Operating mode illustration:

FIGURE 23 – BUSINESS CASE 3 ILLUSTRATION:
STORAGE PROVIDING T&D DEFERRAL FOR A PERIOD OF 3 DAYS

T&D CAPACITY REQUIRED AND AVAILABLE, MW



Business case findings:

- The T&D upgrade deferral business case is special, as it is almost completely location-specific. In particular, the cost of the deferred T&D upgrade, the siting restrictions, the required response time and ramp rate as well as the required storage capacity differ in each situation.
- Our analysis shows that the amount of deferred investment is the main sensitivity. T&D deferral will thus find its first markets in situations where the upgrade would be very costly (underground or undersea cables, locations with difficult access). Alternatively, storage could be used if it is not possible to obtain the required permits for the T&D upgrade in time and if it is not possible to enter into demand-side response contracts of sufficient size and duration. In this case, the storage would be deployed to relieve the localised constraint rather than be based on a stand-alone business case.
- The regulatory implication of this business case is the need to clarify under which conditions TSO/DSO can own and operate the storage or purchase the T&D deferral service from external providers. Also, the regulatory treatment of energy that is taken out of the market and is later resold needs to be clarified, as this would mean that the TSO/DSO would in effect be trading in the wholesale market.

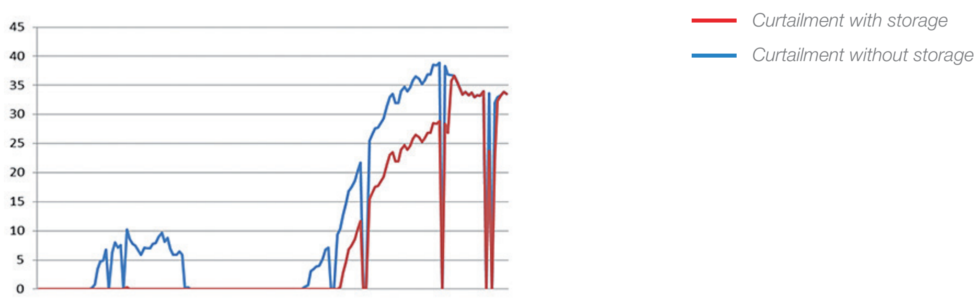
4) P2P STORAGE USED TO REDUCE WIND GENERATION CURTAILMENT AND INTEGRATE THE EXCESS POWER INTO THE GRID

Business case description:

- Storage is increasing the revenues of a wind park by absorbing energy that cannot be fed into the grid due to T&D constraints (storage charges from energy that would otherwise be curtailed) and discharging at times when T&D capacity is available. This revenue source is only applicable in situations where regulation does not guarantee that the RES producer is remunerated for curtailed electricity.

Operating mode illustration:

FIGURE 24 – BUSINESS CASE 4 ILLUSTRATION:
STORAGE REDUCING WIND FARM CURTAILMENT OVER THE PERIOD OF 2 DAYS, MW



Key parameters:

- Position in the grid: coupled with wind generation unit
- Wind farm size: 100 MW
- Curtailment above: 40 MW
- Baseline storage size: 10 MW/80 MWh
- Technologies considered: PHES, CAES, LAES, Li-ion batteries, NaS batteries, lead-acid batteries
- Wind feed-in tariff (FIT): EUR 88/MWh.

Business case findings:

- The business case where P2P storage is used for grid integration of wind energy that would be locally curtailed remains negative in 2030. Moreover, the business case is difficult to improve. Given the wind production patterns (frequent periods of several days of high production followed by several days of low production), the energy-to-power ratio has to be high if a meaningful share of the curtailed wind energy is to be integrated. This, however, results in a low cycle life and damages the economics of the case.
- A storage asset with a very low energy-to-power ratio (0.5:1) would be able to achieve break even. However, such storage assets would only be able to reduce curtailment by a small fraction.

- Furthermore, the feasibility of this business case depends on the regulatory treatment of curtailment. In some countries (e.g., Germany), wind farm operators are paid out a large proportion (95-100%) of the relevant FIT for energy that is curtailed. This removes incentives for the wind farm operator to store the energy and integrate it into the grid at a later point, or otherwise productively use the energy. Curtailment payments thus present a potentially large obstacle for the use of storage (both P2P and hydrogen) for productive utilisation of excess renewable energy.

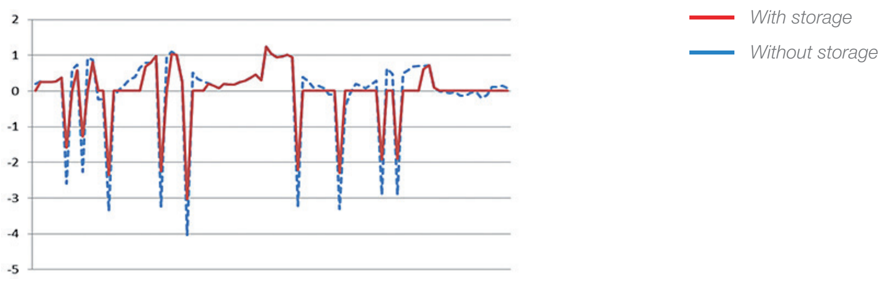
5) P2P STORAGE USED FOR SHORT-TERM FIRMING OF WIND GENERATION OUTPUT

Business case description:

- Storage is used for "firming" of wind turbine output and ensuring that the wind farm is able to provide predictable power in four-hour intervals.
- Benefit of storage comes from avoiding penalties for both positive and negative deviations from the forecast.
- The viability of this business case is based on the assumption that there is a benefit for wind farm operators to be able to guarantee a more predictable production profile than provided by operation of the wind farm without storage. Under current European regulation, this is generally not the case and VRE enjoys preferential access to the grid.

Operating mode illustration:

FIGURE 25 – BUSINESS CASE 5 ILLUSTRATION:
REDUCTION IN DEVIATION FROM FORECAST PRODUCTION OVER A PERIOD OF 2 DAYS, MW



Key parameters:

- Wind output capacity: 10 MW
- Forecast period length: four hours
- Baseline storage size: 1 MW/2 MWh
- Technologies considered: Li-ion, flow and NaS batteries
- Penalty from deviation from forecast: EUR 50/MWh
- No deviation tolerance band.

Business case findings:

- This currently hypothetical business case serves as an illustration of the ability of P2P storage to integrate wind energy into the grid. The potential of this business case to be profitable lies in the short periods of time for which energy needs to be stored – enabling it to reach a relatively high utilisation at low energy-to-power ratio. This contrasts sharply with the previous case of integrating curtailed wind into the grid.

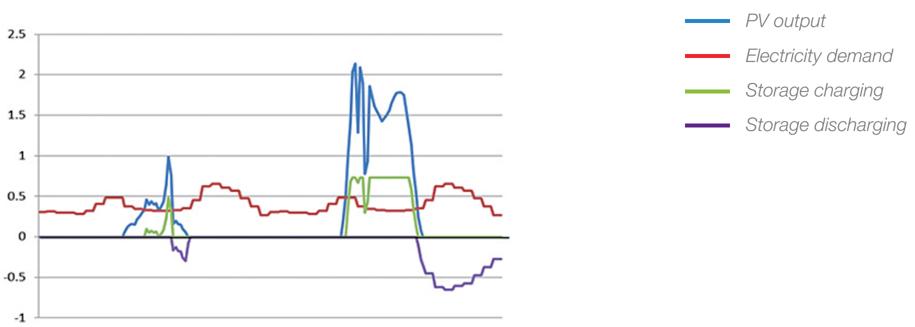
6) P2P STORAGE COUPLED WITH HOME PV TO MINIMISE THE AMOUNT OF POWER PURCHASED FROM THE GRID

Business case description:

- In residential setting, storage is charging from PV output exceeding immediate demand and is discharging during times of positive residual demand.
- Storage is reducing the amount of electricity required from the grid (at retail price, including transmission and other fees) and the amount of PV-generated electricity exported to the grid.
- Profit is generated from the difference in FIT and retail electricity cost, lowered by efficiency loss.

Operating mode illustration:

FIGURE 26 – BUSINESS CASE 6 ILLUSTRATION:
DYNAMICS OF STORAGE USED FOR EXCESS HOME PV INTEGRATION OVER A PERIOD OF 2 DAYS, KW



Key parameters:

- Position in the grid: coupled with home PV
- House consumption: 3,500 kWh/year
- PV size: 5 kWp
- Baseline storage size: 1 kW/5 kWh
- Technologies considered: Li-ion, lead-acid, NaS, flow-V batteries
- PV FIT: EUR 120/MWh
- Retail electricity cost (including fees): EUR 270/MWh.

Business case analysis:

- A small-scale storage coupled with home PV has a positive business case in 2030 and, at the low range of cost estimates for lead-acid batteries, already in 2014. This is driven by a combination of a relatively high utilisation (due to daily solar cycles of several hours' duration) and a high spread between the final consumer grid price, including all fees and levies as well as the price at which the PV-generated energy would be fed into the grid.
- The business case would potentially be further improved if time of use metering were introduced. This would enable a targeted discharging of the storage at times of high prices, increasing the benefit per each discharged MWh.
- A change in regulation that would change the structure of grid fees and other levies from a per-MWh basis to a fixed amount per connection point represents a threat to this business case. This would reduce the benefit of each MWh discharged.

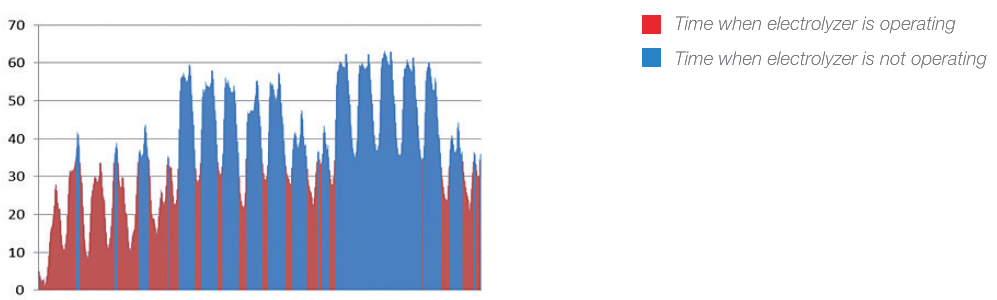
7) ELECTROLYSER CONVERTING ELECTRICITY TO HYDROGEN FOR USE OUTSIDE OF THE POWER SECTOR

Business case description:

- An electrolyser converts electricity into hydrogen during a set percentage of hours with the lowest electricity price
- Hydrogen is sold and used outside the electric power sector (e.g., for mobility or industry use).

Operating mode illustration:

FIGURE 27 – BUSINESS CASE 7 ILLUSTRATION:
RESIDUAL LOAD IN GW AND TIMES OF ELECTROLYSER OPERATION OVER A PERIOD OF 2 WEEKS



Key parameters:

- Utilisation: 50% of the year with lowest electricity prices (within an optimum range of trade-off between utilisation and electricity price)
- Average wholesale power price at which the electrolyser is charging at given utilisation (EUR 25/MWh in 2014, EUR 33/MWh in 2030) is based on the German high-RES scenario
- Electrolyser size: 10 MW
- Technologies considered: alkaline, PEM and SO electrolysers
- Low range of 2030 capex cost and following 2030 parameters used:
  - Alkaline: EUR 370/kW, 50 kWh/kg of hydrogen, 10 years lifetime
  - PEM: EUR 250/kW, 47 kWh/kg of hydrogen, 10 years lifetime
  - Solid oxide: EUR 625/kW, 43 kWh/kg of hydrogen,[33] 10 years lifetime
- On-site storage included to store daily production (base case 240 MWh – one day's storage at EUR 5/kWh of storage capacity)
- Neither costs of transportation and delivery, nor additional infrastructure costs are included; hydrogen is assumed to be either used locally or stored in cost-effective salt cavern storage if storage capacity in excess of on-site storage is required.
- No network fees, levies and taxes on electricity are included in the base case.
- The 2013 hydrogen benchmark price is at EUR 2/kg, the 2030 hydrogen price at EUR 2.5/kg.

Business case analysis:

- Under the base case assumptions, the 2030 business case is slightly negative (profitability index of about 0.9) for alkaline and solid oxide electrolysers and is positive for PEM electrolyser (profitability index of about 1.5), driven by its combination of low capex and higher efficiency.
- The business case is highly sensitive to several factors, the most important of which include:
  - The price of hydrogen realised in the market – electrolysers produce higher purity hydrogen than SMR and may command a purity premium for some applications.
  - Additional storage and transportation costs – the business case for all three technologies turns negative when the required on-site storage exceeds three days. Hydrogen transportation costs also reduce the profitability of the business case.
  - Electrolyser lifetime – for all three technologies, 10 years of lifetime are assumed. At 50% utilisation, the electrolyser lifetime will likely be longer, reducing the capital charge per kg of hydrogen produced. In the base case, the alkaline electrolyser would achieve break even at 12 years of lifetime.
  - The ability to provide frequency reserve services to the grid (electrolyser acting as controllable load) – this could increase the revenues of the electrolyser (equivalent to reducing costs of produced hydrogen by up to EUR 0.6 /kg).[34]
  - Introducing final consumption electricity grid fees and levies.

In summary, positive business cases for grid-connected electrolysers producing hydrogen may exist in suitable locations (where the need for on-site storage and further transportation is low) if the generated hydrogen is exempt from electricity grid fees and levies.

33 Higher efficiency can be achieved if waste heat from other processes can be used during electrolysis

34 FCH JU: Development of Water Electrolysis in the European Union, February 2014

STACKING OF SERVICES

Using storage for multiple business cases at the same time or sequentially ("stacking" of services) could improve its profitability. This requires synergies in providing multiple services by one storage unit compared to providing the stand-alone services through more storage assets.

There are several ways how storage services can be stacked to achieve synergies:

- The same storage energy capacity can be used sequentially for the provision of different services, depending on profitability at any given time (e.g., using storage for T&D deferral seasonally and for time shift or frequency reserve for the rest of the year).
- Storage energy capacity may be split between two services, but provision of one of the services is enabled by the possibility to share energy capacity (e.g., using 10 MW out of the total capacity of a 150 MW per eight hours pumped hydro storage to guarantee provision of secondary reserve for the duration of one week and using the remaining capacity for time shift).
- The same storage energy capacity can be used for more services at the same time – either receiving multiple capacity payments for the same capacity or receiving a capacity payment and using the same capacity for a different service (e.g., using non-perfect correlation of the direction of charging signal to deliver primary and secondary reserve together with capacity that is lower than the sum of the capacities required for the stand-alone services).

However, the viability of stacking is not straightforward due to several constraints:

- Technical constraint: cases need to be delivered by the same technology, restricting the ranges of response speed and charge/discharge rate of the chosen technology.
- Operational constraint: the charging and discharging profiles of the services need to be compatible. In particular, for contingency services (T&D deferral and frequency reserve), the need to ensure that the service is available whenever called upon restricts the possibility to use the same capacity for a different purpose.
- Market constraint: storage can be operated by various stakeholders along the power value chain, and regulation might restrict the type of services a stakeholder class can deliver. Furthermore, different services could deliver the benefit across different stakeholder groups and monetisation of the benefit from a different customer class may be challenging.

During the study, the coalition identified several viable examples of stacking:

- Seasonal T&D deferral combined with either time shift or provision of frequency reserve
- T&D deferral subsequently at several grid points through mobile storage
- Dedicating part of the storage power capacity to the provision of frequency reserve and the remainder to time shift, enabling storage to guarantee provision of frequency reserve for periods longer than its energy-to-power ratio
- Using an electrolyser to produce hydrogen and varying load in response to the frequency reserve needs of the grid.

Other stacking combinations may be possible but are highly dependent on the charging and discharging profiles of individual services, the ability of the storage operator to forecast them and the regulatory stance on allowing stacking, especially for contingency services (frequency reserve and T&D deferral). General statements about their feasibility or profitability are therefore not possible.

Part 4:

Energy storage commercial regulation: overview and recommendations

Key finding 7

There is a low degree of regulatory acknowledgement of storage as a specific component of the electric power value chain – and hence a lack of storage-specific rules and insufficient consideration of the impact of regulation on storage. The key obstacles to storage identified by the study are:

- Lack of clarity on the rules under which storage can access markets – in particular the inability of TSOs and DSOs to own and operate storage, or purchase T&D deferral as a service in some countries, or lack of rules concerning the access of storage to the ancillary services market
- Application of final consumption fees to storage (including P2G), even though storage does not constitute final use of the energy
- Payments for curtailment to RES producers, removing an incentive for productive use of the curtailed electricity.

At present, most European countries do not have in place a specific commercial (as opposed to technical and safety) regulation of energy storage. In the absence of storage-specific regulation, storage is treated as a combination of power consumption and generation and has to conform to relevant rules for both operating modes. While examples of progressive regulation exist both among EU countries and outside of Europe, national legislation only addresses part of the whole topic. Within Europe, Germany has currently the most developed – although not necessarily most favourable – regulation governing energy storage. Worldwide, California is the front-runner, including the mandate to deploy 1,325 GW of storage technologies across the power value chain by 2020. Our analysis shows that the business cases are often made unfeasible by the existing regulation – a regulation development is therefore needed.

As demonstrated in the business-case section, regulatory environment is key to commercial viability of storage technologies. Before 2030, there will potentially be several profitable business cases for storage. However, regulatory obstacles would hinder a profitable deployment of many of them and prevent the storage technologies from developing.

This chapter provides a broad overview of current regulation pertaining to energy storage in energy markets of selected EU countries. Specifically, the study examines how current regulation addresses access to markets and remuneration of energy storage use for time shift, frequency reserve and T&D deferral as well as conversion to hydrogen for applications outside the electric power sector. Next, we present examples of more progressive regulation from outside of Europe and summarise the findings for regulatory implications of the business cases. Finally, there are recommendations for removing regulatory obstacles to enable further development of storage and further research suggestions to comprehensively assess the new regulatory options.

The study reviewed the regulation governing the participation of energy storage technologies in energy markets for the five largest countries by consumption of electric power in the EU (Germany, the UK, France, Italy, Spain), together accounting for over 75% of total the EU power consumption, and also the regulation of non-connected Greek systems.

Based on our review, none of the countries has comprehensive regulation for electricity storage technologies, and most of the countries do not have a specific regulation for electricity storage besides historically regulated pumped hydro plants. In the absence of particular regulation, storage is treated as a combination of both power consumption and power generation, and it has to conform to the relevant rules. In the island system of Greece, on the other hand, only the so-called "hybrid stations", i.e., storage coupled with renewables, are specifically regulated.

MARKET ACCESS

- Time shift: access of storage technologies to wholesale market for time-shift application is generally allowed in all reviewed countries, however, in some countries (e.g., France, Spain, Italy and Greece), only pumped hydro is explicitly considered by regulation for this application.
- Frequency reserve: current regulation in Germany and the UK enables participation of storage technologies in frequency reserve markets via combined offerings ("pooling") with other providers. In other reviewed countries, only pumped hydro is able to provide frequency regulation.
- T&D deferral: use of storage for T&D deferral is currently possible only in Italy and the UK. Generally in Europe, TSOs and DSOs are not allowed to have control over an electricity-generating facility due to the unbundling requirement of Article 9 (1) of the Electricity Directive. Thus, in absence of storage-specific regulation and to the extent that storage is treated by regulation as generation, TSOs and DSOs cannot operate storage assets.[35] The UK enables small generating facilities, including energy storage, to obtain exemption from the obligation to hold a generation licence on a case-by-case basis, which enables TSOs and DSOs to deploy smaller-scale energy storage for T&D deferral. National legislation in Italy also allows TSOs and DSOs to build and operate storage if it is proven to be the most efficient way to address T&D problem.[36]

35 2013, Store: European Regulatory and Market Framework for Electricity Storage Infrastructure
36 Art 36, paragraph 4, decree law 93/11

FIGURE 28

Storage can access time-shift market in all countries surveyed, but its ability to provide frequency reserve and T&D deferral is limited to certain countries

✓ Allowed ✗ Not allowed ✓ Regulation only governing pumped hydro

	DE	FR	GB	IT	ES	GR[1]
	Can storage participate in the wholesale market?					
Time-shift	Allowed	Allowed	Allowed	Allowed	Allowed	Allowed
	Can storage participate in the frequency reserve market?					
Frequency reserve	Allowed	Regulation only governing pumped hydro	Allowed	Regulation only governing pumped hydro	Regulation only governing pumped hydro	Regulation only governing pumped hydro
	Can TSO/DSO own and operate storage?					
T&D	Not allowed	Not allowed	Allowed[2]	Allowed[3]	Not allowed	Not allowed

1 Existing regulation is pertaining to hybrid stations only (renewables coupled with storage) in non-interconnected islands
2 Allowed for small storage assets
3 If proven as most cost effective solution

REMUNERATION

- Time shift: from the remuneration perspective, there is even less storage-specific regulation than for the access of storage to the above-mentioned applications. Operating in consumption and generation modes, storage may be subject to fees relevant to both operating modes in the absence of storage-specific regulation.
  - Presence of double grid fees in certain countries (e.g., Greece) is an example of treatment where storage technologies both in charging (i.e., consumption mode) and discharging (i.e., generating mode), which has negative impact on storage profitability.[37]
  - Germany has the most advanced regulation also regarding the remuneration of storage technologies. It exempts interim-stored electricity from the renewables levy (EEG) and a lowered rate is applied to electricity lost due to cycle efficiency. Electricity charged to storage is exempt from the consumption tax, but only if it is 100% renewable; otherwise the consumption tax would apply. Pumped hydro storage can also receive exemption from the consumption tax for electricity used in the charging mode according to current regulation. [38]New storage and refurbished pumped hydro are also exempt from network usage fees for 20 years of operation. Furthermore, German regulation preserves to storage the remuneration payable to renewables for power directly fed into the grid. Thus, storage will receive the FIT according to used technology when discharging interim-stored power to the grid. To receive the FIT, electricity stored must be 100% renewable.
- Frequency reserve: if possible, participation of storage technologies in frequency reserve markets is remunerated identically as in the case of all other providers: no allowance is made for faster ramping resources as seen in California. Because the ancillary services provision differs between EU and the US, the solution may not be applicable.
- T&D deferral: there is no storage-specific remuneration scheme and respective regulation. TSOs and DSOs benefit from capex savings from avoiding or substituting conventional grid upgrades. As already mentioned before, the UK allows TSOs and DSOs to own and operate small-scale storage for T&D deferral, but caps the turnover from non-distribution activities at 2.5% of distribution business revenues.[39]

37 See EURELECTRIC: “Euro Needs Hydro Pumped Storage: Five Recommendations”, May 2012

38 § 9, 1, 2 StromStG in conjunction with § 12, 1, 2, StromStV

39 2013, Smarter Network Storage: Electricity Storage in GB

EU REGULATION RELATED TO HYDROGEN PRODUCTION AND APPLICATION

Commercial regulation of electrolytic hydrogen production and applications is currently very limited. The regulation primarily addresses safety, technical and environmental issues, but general rules for the access and remuneration of electrolysers, fuel cells and produced hydrogen are missing.

- Access: access of electrolysers to the power grid is allowed under the same conditions that apply to final consumers. Generally, electrolysers and fuel cells must comply with ISO standards as well as EU safety, technical and environmental directives to receive the CE marking required for items sold within EEA. For P2G applications, the connection of installations providing hydrogen is typically arranged on a case-by-case basis. In Germany, already today the gas grid operator is obliged to connect installations providing "biogas", including hydrogen, to the grid. A generally acceptable hydrogen admixture limit to the gas grid is below 10%, but exact volumes are managed by the gas grid operator who needs to make sure that injected hydrogen will not cause problems to end consumers.
- Remuneration: regulation of the remuneration of electrolytic hydrogen itself is very scarce. Some countries, e.g., Germany and the UK, allow electrolysers to operate as controllable load by providing access to the ancillary service market, which gives electrolysers an additional revenue stream option and may decrease the cost of hydrogen produced. In Germany, the production of hydrogen is exempt from the electricity consumption tax and also from the renewables levy (EEG), but only if the hydrogen is re-electrified and used in the power sector.

  For P2P applications, Germany provides FIT to power made from green hydrogen based on the origin of the initial power source, e.g., a wind plant. On top, a feed-in bonus is awarded to re-electrified hydrogen from small fuel cell installations. Remuneration in the form of FIT for green hydrogen for P2G applications is currently not observed in any of the countries reviewed. However, in Germany, green hydrogen with a minimum of 80% renewable input is granted the same feed-in bonus as "biogas".

EXAMPLES OF MORE STORAGE-FRIENDLY REGULATION FROM OUTSIDE OF EUROPE

To understand the current status and trends of regulation for energy storage, the study also looked outside Europe.

From the countries reviewed, the US has recently made the most considerable changes to power market regulation. They focused particularly on allowing storage technologies to access the ancillary service market and introducing performance-based remuneration for the provision of ancillary services. Specifically:

- The Federal Energy Regulatory Commission (FERC) order No. 719 of 2008 directed independent system operators (ISOs) and regional transmission organisations (RTOs) to open markets for new technologies that can provide ancillary services. This provision opened a door also to storage to provide the frequency regulation service.
- In 2011, FERC order No. 755 required ISOs and RTOs to compensate providers of frequency regulation based on their performance. Following this order, a two-tier remuneration system was introduced for the provision of regulating power. The first payment remunerates the provider for the capacity dedicated to ancillary services, and the second, additional payment – also known as "mileage" – compensates the provider for the regulation actually supplied to the grid. Because fast-ramping resources, including storage, are able to follow the frequency signal more accurately and provide more actual regulation to the grid, they get paid more for the service.
- Within the US, but also worldwide, California has created the most storage-supportive environment by passing the Energy Storage Law (AB 2514). This law requires utilities to procure storage technologies equal to 2.25% of peak load by 2015 and 5% by 2020. California thus became a pioneer in mandating deployment of storage for the purpose of renewable integration and ancillary services.
- California's largest investor-owned utilities (Southern California Edison, Pacific Gas and Electric as well as San Diego Gas and Electric) need to jointly invest in and deploy 1,325 GW of energy storage by 2020 into the transmission, distribution and consumption being part of the power value chain. Procurement targets were set by the California Public Utilities Commission (CPUC) as a compromise between what was deemed cost-effective and technically achievable with the aim to set realistic targets and allow for proper planning and safeguards.

LESSONS LEARNED FROM THE ANALYSIS OF BUSINESS CASES FROM THE REGULATORY PERSPECTIVE

Our evaluation of business cases shows that a profitable deployment of storage in the future will be subject to removing obstacles preventing storage from market participation. The analysed business cases could be further improved by introducing new regulatory arrangements that change the way the energy system is currently governed.

The following regulatory changes have been identified as having the potential to improve specific business cases. These regulatory options should not be interpreted as a recommendation, as their inclusion in the regulatory framework must be based on a careful analysis of the impact on all stakeholders within the energy sector.

Business case	Regulatory changes enabling or improving business case
1) P2P storage providing grid-level daily time shift	• Introduce a capacity remuneration scheme: capacity payments to conventional generators and other dispatchable backup capacity (including storage)
2) P2P storage providing secondary frequency reserve	• Differentiate payments for frequency reserves based on speed and ramping capacity: provide higher payments for sources that are better suited to follow frequency regulation signal (pay for "mileage") • Enable access to the market for storage with limited energy capacity: reduce the duration of periods for which frequency reserve services have to be reliably provided and increase the number of tendering periods accordingly
3) P2P storage used for T&D upgrade deferral	• Allow storage access to the market: clarify rules under which TSOs/DSOs can operate storage or purchase T&D deferral as a service from third parties
4) P2P storage used to reduce wind generation curtailment and to integrate the excess power into the grid	• Remove price signal distortions caused by compensating curtailment: find alternative ways of compensating renewables producers so that curtailment payment is not an obstacle to storing the energy that would be curtailed • Ensure FIT/FIP (feed-in premium) is conserved for renewable electricity discharged from storage: conserve FIT for all renewable energy stored. If storage is charged both from renewables and non-renewables, conserve FIT/FIP for the renewable part
5) P2P storage used for short-term firming of wind generation output	• Include producers of renewables electricity in the balancing market: increase responsibility of renewables producers for deviation between forecast and supplied energy
6) P2P storage coupled with home PV to minimise the amount of power purchased from the grid	• Introduce time-of-use pricing at consumer level: set time-of-use pricing for households to encourage reduction of load at times of high residual demand (e.g., via use of storage)
7) Electrolyser converting electricity to hydrogen	• Exempt electrolyser from final consumption fees when hydrogen is used outside power sector: enable integration of power and gas sectors as well as use of renewable electricity where it has the highest value/can contribute most to CO2 reduction

RECOMMENDATION

Our analysis of the regulatory situation from the energy storage perspective in the reviewed countries as well as our evaluation of business cases for storage indicates that significant development of the current regulation is needed. There are three types of regulatory changes that can support the deployment and further commercialisation of storage:

- Removing obstacles to storage and hydrogen storage applications stemming from current regulation
- Introducing new regulation changing the overall energy system regulation
- Providing support during the initial phase.

REMOVING OBSTACLES TO STORAGE APPLICATIONS

The minimum improvements the current regulation requires are changes that set a level playing field and remove obstacles preventing storage from participation in power markets. The main pitfall of the current regulation observed is thus a lack of storage-specific regulation causing obstacles to storage deployment. To that end, the new regulation should:

- Explicitly acknowledge storage as a separate asset class to encourage its differentiated treatment in applicable uses
- Recognise that storage (including P2G) is not final consumption and should not be regulated as such:
  - Storage should be exempt from final consumption fees and levies
  - Storage should not be subject to double grid or discriminatory fees
- Define conditions under which storage can participate in ancillary services markets, including minimum capacity, minimum availability time, maximum duration of service provision and minimum intervals between repeated provision of reserve
- Clarify conditions and limitations under which network operators (TSOs, DSOs) are allowed to own and operate a storage asset or purchase the T&D deferral service from external providers.

INTRODUCING A NEW REGULATION CHANGING THE OVERALL ENERGY SYSTEM REGULATION

Besides removing obstacles stemming from the current regulation, business cases for storage can be improved by considering new regulatory provisions described in the business case analysis section above. Importantly, new regulatory proposals as well as the existing regulation need to be consistent with EU energy policy objectives as set in the Treaty of Lisbon. The objective of the regulation is thereby to[40]:

- Ensure the functioning of the energy market
- Ensure the security of energy supply in the EU
- Promote energy efficiency and energy saving as well as the development of new and renewable forms of energy
- Promote interconnection of energy networks.

40 http://www.europarl.europa.eu/aboutparliament/en/displayFtu.html?ftuId=FTU_5.7.1.html

New regulatory options should thus be further analysed and researched to understand and assess their potential impact on all stakeholders in full complexity and to make sure that they fulfil the general regulation objectives. Examples of potential impact on key stakeholders resulting from new regulatory options are indicated in the table below:

Selected regulatory options	Potential impact on key stakeholders (non-exhaustive examples)
Introduce capacity remuneration scheme	• Final power consumers: depending on how capacity remuneration is implemented, it may lead to an increase in electricity costs for final consumers
Exempt electrolyser from final consumption fees when hydrogen is used outside the power sector	• Consumers in power, gas and mobility sectors: incidence of the costs for decarbonisation would depend on allocation of final consumption levies to individual sectors
Differentiate payments for frequency reserves based on speed and ramping capacity	• Conventional generators: decrease in frequency reserve remuneration from slower/less accurate thermal sources if total frequency reserve remuneration amount is kept unchanged
Remove price signal distortions caused by compensating curtailment	• Renewable generators: removing payments for curtailment could adversely impact renewables profitability and their further build-up
Include renewables producers in the balancing market	• Renewables generators: increases costs of producing RES power and could adversely impact renewables profitability and their further build-up
Introduce time-of-use pricing at consumer level	• Grid-level storage: time-of-use pricing at consumer level would lower residual load fluctuations at grid level, reducing the opportunity for grid-level storage • TSOs and DSOs: – Introducing time-of-use pricing may require upgrades to infrastructure (e.g., smart metering); the costs may have to be borne by final consumers – Smoothing local demand profile may reduce required T&D upgrade investments

PROVIDING SUPPORT DURING THE INITIAL PHASE

On top of removing obstacles and introducing new regulatory arrangements, deployment of storage technologies can be further supported by other measures with the aim to decrease costs of technologies and accelerate their commercialisation, similarly to solar and wind technologies in the past. Potential support measures should be considered only in the initial deployment phase and were not further analysed by the study.

Additional modelling assumptions

MODELLING APPROACHES

We used two complimentary modelling approaches to investigate the demand for and value of storage for time-shift application. The primary approach was based on country archetype modelling, and the complimentary approach used the EU power model to crosscheck the main outcomes.

1. Country archetype modelling

The country archetype model analyses the supply-demand balance of an electric power system. The model covers one year in 15-minute intervals (35,040 periods per year). The key inputs to the model are renewables installed capacity, renewables unit generation profiles (differentiated between offshore, onshore, PV solar and biomass), electricity demand profile, installed capacity of non-RES generation (nuclear, coal, gas, oil) and short-run marginal costs of non-RES generation, including CO2 costs. The model first determines residual demand based on the demand profile and RES generation profiles. Then it calculates the amount of energy required from the non-RES sources as well as the fuel type used to provide this energy according to the short-run marginal cost merit order. The key outputs of the model are (for each 15-minute interval): residual demand (amount of excess energy or required further generation), non-RES generation by fuel type and non-RES generation costs, including CO2 costs.

Adding storage in the model allows changing the shape of the residual demand, which is subject to constraints determined by storage characteristics (power capacity, energy capacity, round-trip efficiency). The benefits of storage in the model are equal to fuel and CO2 savings achieved by the change in the resulting non-RES generation dispatch.

Two different operating modes of storage were modelled:

1. Storage absorbs excess energy (charges whenever there would be curtailment) and uses it to reduce backup capacity (discharges as soon as the curtailment stops).
2. Storage smoothes residual demand on a daily basis. Storage discharges eight hours per day with the highest residual load and charges eight hours per day with the lowest residual load.

For each year and scenario, we consider an operating mode with greater benefits to calculate the value of storage.

The archetype modelling was carried out using spreadsheet software.

For the modelling, we selected four countries/regions that represent different archetypes observed in Europe:

- Germany, a large Central European country with a high share of intermittent renewables and nuclear phase-out after 2022
- Spain, a large Southern European country with a high share of intermittent renewables
- Sweden, a medium-sized Nordic country with a high share of hydro power
- Crete, a Mediterranean island with a high share of intermittent renewables.

To understand the impact of T&D and must-run constraints on the value of storage, the following cases were modelled:

- Base case: each country is treated as an island (no international connections) based on the assumption that there are no internal T&D constraints in the country and no must-run constraints.
- "T&D constraints" case: this case is based on the assumption that there is no development in T&D networks and that the highest historically observed VRE absorption is the maximum that the grid can accommodate.
- "Copperplate Europe" case: assesses the impact of treating three of the modelled country archetypes (Germany, Spain, Sweden) as a single system with no T&D constraints and no must-run constraints. This approximated the case when substantial T&D capacity would be built up.

2. EU power model

To crosscheck the main results obtained by using our primary "Archetype modelling approach", we used the Plexos power system modelling software, which includes demand and generation capacity for 22 countries.[41] The model assumes capacity for interconnection between the countries, however, internal T&D constraints are not considered.

The Plexos model operates to optimise the total cost of the power system based on one-hour time resolution data during the 8,760 hours of the year.

ASSUMPTIONS FOR ARCHETYPE MODELLING

1. Supply

Capacity mix:

- For the reference scenario, the installed capacity mix for each of the modelled archetypes was based on the European Commission's EU Energy, Transport and GHG Emissions Trends to 2050 report. For the cases where supply significantly exceeded demand according to report forecasted scenarios (Sweden only), we scaled down generation to exceed demand by a maximum of 10%. This eliminated excess generation that would otherwise have been observed in the model and that would have been available for time shift. In reality this excess generation currently does not exist, as overgenerated electricity is exported.
- For the high-RES scenario, we used national installed capacities from the reference scenario, which we scaled up by EU-27-wide trends for renewables penetration growth. EU-27-wide installed capacities and respective scaling factors are based on the European Commission's Energy Roadmap 2050 report.

41 EU excluding Ireland, Luxembourg, Cyprus, Malta, Estonia, Latvia, Lithuania and Croatia, but including Norway and Switzerland

Intermittent renewables (wind onshore, wind offshore, solar):

- We used historical hourly profiles and scaled them up according to the assumed future capacity for each intermittent RES.

Hydro:

- The installed capacity of hydro is forecast to remain rather stable across the modelled years and scenarios. Run-of-river generation and reservoir inflows are based on historical monthly water inflows. Generation from reservoir hydro plants is activated in the model at times when residual demand is high, while keeping the year-end reservoir level equal to year-start level to ensure sustainability of its operation.

Nuclear and biomass:

- Constant capacity factor is assumed throughout the year.

Thermal:

- The thermal backup consists of solid, gas and oil generation. No carbon capture and storage (CCS) is assumed.

2. Demand

Yearly demand:

- For the reference scenario, country-specific demand is available and used from the European Commission's EU Energy, Transport and GHG Emissions Trends to 2050 report. For the high-RES scenarios, country-level demand is scaled from the reference scenario based on EU-wide data. Yearly demand includes final electricity demand and T&D losses.[42]

Base profile:

- An hourly historical country profile is scaled up in line with yearly power demand.

3. Grid

Interconnections:

- In the base case, both in reference and high-RES scenarios, the archetypes are modelled as islands with no interconnection capacity to neighbouring countries; in the "copperplate Europe" case, unlimited interconnection capacity between the countries is assumed.

T&D constraints:

- For all scenarios, no intra-country transmission and distribution constraints have been assumed, in other words, we are applying the so-called "copperplate" assumption.
- The "T&D constraints" case limits the intermittent renewables in-feed to the maximum observed absorption in the 2013 scenario and is based on the assumption that the rest is excess energy that would be curtailed in absence of storage technologies.

42 Assumes that T&D losses account for 75% of plants set selfconsumption and grid losses; energy branch consumption neglected

4. Commodities

PRICES OF COMMODITIES AND CO_2

Commodity	2013	2030	2050
Gas (EUR/MWh)	27	36	36
Coal (USD/tonne)	83	140	170
CO2 (EUR/tonne)	5	35	100

5. Further modelling parameters

INSTALLED CAPACITIES, GW
EUROPEAN COMMISSION SCENARIOS

EU-27 – reference scenario	2015	2030	2050
Nuclear energy	123	107	122
Hydro (excl. pumping)	116	123	132
Wind	123	305	412
Solar	76	149	230
Other renewables (tidal, etc.)	1	3	7
Thermal power (excl. biomass)	486	446	471
Total	925	1,132	1,374

EU-27 – high-RES scenario	2015	2030	2050
Nuclear energy	126	90	41
Hydro (excl. pumping)	112	120	131
Wind	145	470	984
Solar	28	195	603
Other renewables (tidal, etc.)	1	5	30
Thermal power	515	444	429
Total	925	1,324	2,219

ARCHETYPE MODELLING

	Reference	Reference	High-RES	High-RES
Germany	2030	2050	2030	2050
PV solar	53.6	74.3	61.0	136.2
Wind (on- and offshore)	79.1	105.5	106.1	176.3
Biomass	10.5	12.1	18.1	21.2
Hydro total (excl. PHES)	5.8	7.2	5.6	7.2
Thermal (excl. biomass)	74.8	74.6	74.5	68.0
Nuclear	0.0	0.0	0.0	0.0
Total	223.7	273.7	265.3	408.9
Spain	2030	2050	2030	2050
PV solar	17.0	27.8	22.3	55.3
Wind (on- and offshore)	41.4	60.6	63.8	108.7
Biomass	1.7	2.6	3.4	5.5
Hydro total (excl. PHES)	15.1	16.1	14.8	16.1
Thermal (excl. biomass)	46.7	39.7	41.8	24.7
Nuclear	7.0	7.4	5.8	2.5
Total	128.8	154.2	151.8	212.7
Sweden	2030	2050	2030	2050
PV solar	0.2	0.3	0.3	0.6
Wind (on- and offshore)	4.6	7.3	6.0	16.1
Biomass	2.9	3.1	4.9	7.2
Hydro total (excl. PHES)	18.3	18.8	17.9	18.7
Thermal (excl. biomass)	2.8	2.5	3.0	1.8
Nuclear	9.3	10.8	6.7	2.1
Total	38.2	42.9	38.8	46.5

GROSS ELECTRICITY GENERATION, GWH
EUROPEAN COMMISSION SCENARIOS

EU-27 – reference scenario	2015	2030	2050
Nuclear energy	887,261	799,389	923,898
Solids	803,081	475,234	362,360
Oil (incl. refinery gas)	45,708	20,476	21,840
Gas (incl. derived gases)	748,722	734,499	786,463
Biomass waste	188,714	242,597	342,281
Hydro (excl. pumping)	361,611	388,519	416,470
Wind	262,722	766,793	1,073,065
PV solar	96,127	206,106	346,440
Geothermal and other renewables	8,712	16,077	45,316
Total	3,402,657	3,649,690	4,318,132

EU-27 – high-RES scenario	2015	2030	2050
Nuclear	920,951	578,404	179,105
Hydro, wind and solar	716,559	1,838,420	3,744,893
Thermal (incl. biomass)	1,971,864	1,249,481	1,216,567
Total	3,609,375	3,666,305	5,140,565

ARCHETYPE MODELLING

	Reference	Reference	High-RES	High-RES
Germany	2030	2050	2030	2050
PV	55,810	79,359	63,521	145,495
Wind (on- and offshore)	162,565	216,949	218,064	362,595
Biomass	64,539	74,441	111,257	130,250
Hydro total (excl. PHES)	25,917	29,086	25,364	28,939
Thermal	271,419	240,202	189,200	85,195
Nuclear	0	0	0	0
Total	580,251	640,036	607,407	752,475
Spain	2030	2050	2030	2050
PV	35,906	59,193	46,973	116,275
Wind (on- and offshore)	90,495	132,664	139,528	237,564
Biomass	10,410	16,070	20,626	33,474
Hydro total (excl. PHES)	35,967	37,031	35,200	36,844
Thermal	123,165	101,779	81,455	26,301
Nuclear	57,797	61,199	41,900	11,847
Total	353,740	407,936	365,682	462,305
Sweden	2030	2050	2030	2050
PV	210	282	234	490
Wind (on- and offshore)	10,621	17,467	13,920	38,369
Biomass	17,861	19,145	30,082	44,025
Hydro total (excl. PHES)	69,694	70,018	68,208	69,664
Thermal	12	89	67	49
Nuclear	62,890	64,752	47,449	16,040
Total	161,288	171,753	159,960	168,637

TOTAL DEMAND, GWH
EUROPEAN COMMISSION SCENARIOS

	Reference	Reference	High-RES	High-RES
	2030	2050	2030	2050
EU-27	3,460,614	4,084,545	3,500,320	3,797,641

ARCHETYPE MODELLING

	Reference	Reference	High-RES	High-RES
	2030	2050	2030	2050
Germany	579,311	630,453	585,958	586,169
Spain	346,919	396,352	350,900	368,512
Sweden	152,625	165,659	154,376	154,023

Main metrics and mechanics of storage

During charging, energy storage can be seen as load (power consumption), whereas during discharging, storage is playing the same role as dispatchable electricity generation. However, energy storage is a unique asset class in the energy system whose functioning differs in important aspects from both consumption and generation. In this section we review the main characteristics of storage as well as the main parameters influencing its economics.

Energy storage fulfils three functions: to charge, to hold, and to discharge energy. In this study, we consider P2P storage, where the energy carrier that is charged and discharged is electricity, as well as conversion to other carriers (heat and hydrogen) where electricity is charged and the energy is released from storage outside the electric power system in the form of hydrogen or heat.

The maximum power that storage can charge or discharge is usually measured in kW or MW. In this report, we refer to it as charge or discharge power capacity. The maximum energy that storage can hold is measured in kWh or MWh, and we refer to it as energy capacity. Storing energy always results in energy losses. To characterise these, we use round-trip efficiency[43] – the ratio of energy that can be discharged from storage to the energy that is charged into storage.

The finite energy capacity is the main differentiator of storage from dispatchable generation. Dispatchable generation can provide power continuously[44], whereas storage is only able to discharge until it is empty, after which it has to recharge (at least partially) before it is able to resume discharging.

In particular, finite energy capacity adds an extra dimension that needs to be taken into account when describing the utilisation and economics of storage:

- For conventional generation, utilisation measures the ratio of energy delivered to maximum theoretical output that can be delivered by the unit in a period of time. For a 100 MW coal power plant, the maximum annual theoretical output is 876,000 MWh (delivering full 100 MW during all 8,760 hours per year[45]). So if the plant produces 219,000 MWh in the year, its utilisation is 25%.
- For storage, we analogously define discharge utilisation as the total discharge of storage over a period of time divided by the maximum annual theoretical discharge if energy capacity is not a constraint. A storage asset with a 100-MW discharge power capacity delivering 219,000 MWh per year will also have a discharge utilisation of 25%.
- An additional metric specific to storage is the number of cycles per period of time – this indicates how many times the storage is fully charged and discharged[46] in the given time. The number of cycles thus measures the utilisation of the energy capacity. A storage asset with 800 MWh of energy capacity delivering 219,000 MWh per year goes through 274 cycles per year (219,000/800 = 274), whereas one with 1,600 MWh energy capacity delivering the same amount of energy per year goes through 137 cycles per year.

43 In reality, storage has both a charge efficiency and a discharge efficiency, and round-trip efficiency is the product of the two. For the purposes of this study, we simplify and use a single metric – the round-trip efficiency

44 As long as fuel is available (which is almost never a constraint for practical purposes) and disregarding time required for regular maintenance

45 8,760 hours = 365 days x 24 hours, in leap years the total number of hours increases to 8,784

46 Storage can, of course, be charged and discharged only partially. The number of cycles metric is additive in this respect (e.g., treats two 50% discharges as one 100% discharge)

The complexity of storage economics lies in the trade-off between discharge utilisation and the number of cycles:

- If the energy capacity of storage is low, the storage will either be empty or full most of the time and unable to charge or discharge as needed – the resulting discharge utilisation is low.
- If the energy capacity increases, the probability that the storage is ready to charge or discharge when needed rises and, hence, the discharge utilisation improves. However, the number of cycles is bound to decrease as energy capacity increases.
- The optimal ratio of power and energy capacity given a charging and discharging profile will depend on the relative costs of power and energy capacity.

The existence of two-size metrics (power and energy capacity) also means there are two ways as to how to relate the costs and benefits of a storage asset to its size. We can express the annual benefits and total costs of storage per unit of power capacity (EUR/installed kW/year) or per unit of energy capacity (EUR/installed kWh/year). As a matter of convention, we are using EUR/installed kW/year as the preferred metric, while always indicating the power to energy ratio of the storage.

Description of selected technologies

1) Pumped hydro energy storage

Pumped hydro energy storage is able to reduce or stop production and store water when prices are low, and use this water for production when prices are higher. Pumped storage turbines pump water into an upper reservoir and store it when demand is low. When demand and prices peak, the water is released through turbines to a lower reservoir and the electricity is sold at premium prices. Further, thanks to its flexibility and short response time, pumped hydro technology is able to provide regulation services in ancillary markets.[47]

2) Compressed air energy storage (adiabatic and diabatic)

CAES systems use off-peak electricity to compress air and store it in a reservoir, either an underground cavern or aboveground pipes or vessels. When electricity is needed, the compressed air is heated, expanded and directed through an expander or conventional turbine generator to produce electricity.

In case the heat from compression is used to preheat the air before expansion, the process is adiabatic. If external heat input is used to preheat the air by combustion, the process is diabatic.[48]

3) Liquid air energy storage (adiabatic and diabatic)

Air can be turned into a liquid by cooling it to around -196°C using standard industrial equipment. 700 litres of ambient air becomes about 1 litre of liquid air, which can then be stored in an unpressurised insulated vessel. When heat (including ambient or low-grade waste heat) is re-introduced to liquid air, it boils and turns back into a gas, expanding 700 times in volume. This expansion can be used to drive a piston engine or turbine to do useful work. The systems share similar performance characteristics to pumped hydro and can harness industrial low-grade waste heat/waste cold from co-located processes, converting it to power. Capacity and energy being decoupled, the systems are very well suited to long duration applications.[49]

4) NaS battery

NaS battery technology could be used in grid services because of its long discharge period (approximately six hours). Like many other storage technologies, it is capable of a prompt, precise response to grid needs such as the mitigation of power quality events or the response to signals for area regulation.

NaS batteries are only available in multiples of 1 MW/6 MWh units with installations typically in the range of 2 to 10 MW.[50]

47 European Association for Storage of Energy (EASE), European Energy Research Alliance (EERA) (n.d.): *European Energy Storage Technology Development Roadmap towards 2030*
48 California Energy Commission: Energy Storage Systems Evaluation
49 Liquidair.org
50 California Energy Commission: Energy Storage Systems Evaluation

5) Li-ion battery

Rechargeable Li-ion batteries are commonly found in consumer electronic products, which make up most of the total production volume.

They are already commercial and mature for consumer electronic applications (notebooks, cellular phones, MP3 players). Li-ion is the leading technology for plug-in hybrid electric vehicles (PHEVs) and all-electric vehicles.[51]

6) Lead-acid battery

Lead-acid is the most commercially mature rechargeable battery technology in the world. Originally invented in the mid-1800s, it is widely used to power engine starters in cars, boats, planes, etc. There have been few utility T&D applications for such batteries due to their relatively heavy weight, large bulk, cycle-life limitations and perceived reliability issues (stemming from maintenance requirements).

Power output from lead-acid batteries is non-linear, and their lifetime varies significantly depending on the application, discharge rate and number of deep discharge cycles, which can significantly reduce the product life. Innovation in materials is improving cycle life and durability, and several advanced lead-acid technologies are being developed in the pre-commercial and early deployment phase.[52]

7) Flow battery

A flow battery is a rechargeable battery, in which energy is stored in one or more electroactive species which are dissolved in liquid electrolytes. The electrolytes are stored externally in tanks and are pumped through the electrochemical cell that converts chemical energy directly to electricity and vice versa. The power is defined by the size and design of the electrochemical cell whereas the energy depends on the size of the tanks.

With this characteristic flow, batteries can be fitted to a wide range of stationary applications. Principally, this battery technology is very well suited to large- and medium-scale technical operations. As the main advantage of this battery type is the independent scaling of power and energy, it offers a big potential for relatively cheap “weekly” storage, which can bridge the gap between medium-term storage (1-10 hours) and long-term storage (several weeks), for example, to compensate weekly fluctuations of renewable power generation.

Flow batteries are classified into redox flow batteries and hybrid flow batteries. The most important commercially available type of flow battery is the vanadium redox flow battery.[53]

51 DOE / EPRI 2013 Electricity Storage Handbook - Sandia National Laboratories
52 California Energy Commission: Energy Storage Systems Evaluation
53 Badwal et. al: Emerging electrochemical energy conversion and storage technologies, FrontChem

8) Alkaline electrolyser

The electrolyte is an aqueous alkaline solution containing either sodium hydroxide (NaOH) or potassium hydroxide (KOH), and electrodes are commonly made of nickel-coated steel.

The alkaline electrolyser technology is well understood and considered robust, with units in reliable operation for decades. It is the current standard for large-scale electrolysis, and systems have been successfully built at megawatt scale, producing up to 200 Nm3/hour of hydrogen, making them well suited to the storage of large quantities of energy. In energy applications, conventional alkaline electrolyser technology may have drawbacks, such as the relatively limited ability to respond to fluctuation in electrical input (commonly found when integrating renewables such as wind and solar), or lower gas purity in comparison with PEM technology.[54]

9) PEM electrolyser

The PEM electrolyser technology has fast response times to fluctuations in electrical input and can also be operated anywhere between 0 and 100% of nominal capacity, which are important considerations for grid balancing. PEM electrolysers also produce high-purity hydrogen, which can be used directly in many applications with no further purification required.[55]

10) Large-scale hydrogen energy storage

During times of excess power, hydrogen is produced by electrolysis. The gas can be stored at high pressure in pressure vessels like a tube storage or, in very large quantities (over 7,000 tonnes), in an artificial salt cavern. The energy density (kWh/m^3) reaches similar values like a Li-ion accumulator offer (300 kWh/m^3), but just at a fraction of its costs. High energy density in combination with a low storage capex (EUR/kWh) makes it the preferred solution to store energy for weeks of operation. They are applicable in small distribution grids in combination with fuel cells up to large gas-turbine-based systems at the transmission system level, where it provides the grid-forming features like short current power and grid-stabilising inertia that cannot be provided by inverter-connected RES.

54 FuelCell Today: Water Electrolysis & Renewable Energy Systems, 2013
55 FuelCell Today: Water Electrolysis & Renewable Energy Systems, 2013

11) Heat storage

Thermal energy storage (TES) is a key element for effective and efficient generation and utilisation of heat where heat supply and heat demand do not match spatially and in time. This covers effective thermal management in the sectors heating and cooling, process heat and power generation, as well as the increased utilisation of renewable energy systems. A specific feature of thermal storage systems is that they are diversified with respect to temperature, power level and the use of heat transfer fluids, and that each application is characterised by its specific operation parameters.

Heat can be stored in a number of ways:

- Sensible heat storage results in an increase or decrease of the storage material temperature, stored energy is proportional to the temperature difference of the used materials.
- Latent heat storage is connected with a phase transformation of the storage materials, typically changing their physical phase from solid to liquid and vice versa. Stored energy is equivalent to the heat (enthalpy) for, e.g., melting and freezing.
- Thermochemical heat storage is based on reversible thermochemical reactions. The heat stored and released is equivalent to the heat (enthalpy) of the reaction.[56]

56 European Association for Storage of Energy (EASE), European Energy Research Alliance (EERA) (n.d.): *European Energy Storage Technology Development Roadmap towards 2030*

Bibliography

Altfeld, K., Pinchbeck, D. (2013): *Admissible Hydrogen Concentrations in Natural Gas Systems*

Auer, J., Keil, J. (2012): *State-of-the-art electricity storage systems*, Deutsche Bank

Bloomberg New Energy Finance: *Global Renewable Energy Outlook 2013*

Borden, E., Schill, W.-P. (2013): *Policy Efforts for the Development of Storage Technologies in the US and Germany*, Deutsches Institut für Wirtschaftsforschung

Borsche, T., Ulbig, A., Koller, M., Andersson, G. (2013): *Power and Energy Capacity Requirements of Storages Providing Frequency Control Reserves*, Power Systems Laboratory, ETH Zürich

California ISO: *2013 Annual Report on Market Issues and Performance*

Chakrabarti, M., Hajimolana, S., Mjalli, F., Saleem, M., Skyllas-Kazacos, M. (2011): *Progress in Flow Battery Research and Development*, in: "Journal of The Electrochemical Society"

ChemCoast e.V. (2013): *Roadmap for the Realisation of a Wind Hydrogen Economy in the Lower Elbe Region*

Department of Energy & Climate Change (2014): *RHI Biomethane Injection to Grid Tariff Review*

DVGW Deutscher Verein des Gas- und Wasserfaches e.V. (2013): *Entwicklung von modularen Konzepten zur Erzeugung, Speicherung und Einspeisung von Wasserstoff und Methan ins Erdgasnetz*

Ehret, O., Bonhoff, K. (2014): *Hydrogen as a Fuel and Energy Storage: Success Factors for the German Energiewende*, in: "International Journal of Hydrogen Energy," (forthcoming)

Electric Power Research Institute (EPRI) (2010): *Electricity Energy Storage Technology Options*

Electric Power Research Institute (EPRI) (2013): *Cost-Effectiveness of Energy Storage in California – Application of the EPRI Energy Storage Valuation Tool to Inform the California Public Utility Commission Proceeding R. 10-12-007*

Energy and Environmental Economics, Inc. (2014): *Investigating a Higher Renewables Portfolio Standard in California*

Energy Futures Lab, Imperial College London (2012): *Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low-Carbon Energy Future – Report for the Carbon Trust*

EURELECTRIC (2012): *Decentralised Storage – Impact on Future Distribution Grids*

EURELECTRIC (2014): *Taxes and Levies on Electricity in 2012*

European Association for Storage of Energy (EASE), European Energy Research Alliance (EERA) (2013): *Joint EASE/EERA Recommendations for a European Energy Storage Technology Development Roadmap towards 2030*

European Association for Storage of Energy (EASE), European Energy Research Alliance (EERA) (n.d.): *European Energy Storage Technology Development Roadmap towards 2030 – Technical Annex*

European Commission (2008): *HyWays – the European Hydrogen Roadmap*

European Commission (2011): Energy Roadmap 2050

European Commission (2013): *EU Energy, Transport and GHG Emissions – Trends to 2050*

European Commission, FCH JU (2014): *HyUnder – Assessing the Potential, Actors and Business Models of Large-Scale Underground Hydrogen Storage in Europe*

European Commission's DG ENER (2006): *Introducing Hydrogen as an Energy Carrier*

European Commission's DG ENER (n.d.): *The Future Role and Challenges of Energy Storage*

European Commission's Joint Research Centre (2013): *Assessing Storage Value in Electricity Markets*

European Commission's Market Observatory for Energy (2009): *Europe's Energy Position – Market & Supply*

European Commission's Market Observatory for Energy (2010): *Europe's Energy Position –annual report*

European Network of Transmission System Operators (ENTSO-E): *2013 Survey on Ancillary Services Procurement and Electricity Balancing Market Design*

FCH JU (2014): *Development of Water Electrolysis in the European Union*

Fraunhofer Institute for Wind Energy and Energy System Technology (2014): *Erdgassubstitution durch eine forcierte Energiewende*

Fraunhofer Society (2011): *100% Renewables for Electricity and Heat – a Holistic Model for a Future German Energy System*

Gahleitner, G. (2012): *Hydrogen from Renewable Electricity: An International Review of Power-to-Gas Pilot Plants for Stationary Applications*, in: "International Journal of Hydrogen Energy"

German Energy Agency (dena) (2010): *dena Grid Study II – Integration of Renewable Energy Sources in the German Power Supply System from 2015-2020 with an Outlook to 2025*

German Energy Agency (dena) (2013): *Biomethane – the energy system's all-rounder*

German Energy Agency (dena) (2014): *dena-Studie Systemdienstleistungen 2030 –Sicherheit und Zuverlässigkeit einer Stromversorgung mit hohem Anteil erneuerbarer Energien*

GRID +, European Electricity Grids Initiative (EEGI) (2013): *Energy Storage Innovation in Europe*

Grond, L., Holstein, J., Schulze, P. (2013): *Systems Analyses Power to Gas – A Technology Review,* DNV KEMA Energy & Sustainability

Institute for Power Electronics and Electrical Drives (ISEA), RWTH Aachen (2012): *Technology Overview on Electricity Storage*

Inter-American Development Bank (IDB) (2014): *Potential for Energy Storage in Combination with Renewable Energy in Latin America and the Caribbean*

International Electrotechnical Commission (IEC) (2011): *Electrical Energy Storage – White Paper*

International Electrotechnical Commission (IEC) (2012): *Grid Integration of Large-Capacity Renewable Energy Sources and Use of Large-Capacity Electrical Energy Storage – White Paper*

International Energy Agency (IEA), OECD (2014): *Technology Roadmap – Energy Storage*

KEMA, Inc. (2010): *Research Evaluation of Wind Generation, Solar Generation, and Storage Impact on the California Grid*

Low Carbon Networks Fund (2013): *Smarter Network Storage*, UK Power Networks

Marcinkoski, J., Spendelow, J. (2012): *DOE Fuel Cell Technologies Program Record – Fuel Cell System Cost*, US Department of Energy

National Renewable Energy Laboratory (NREL) (2010): *The Role of Energy Storage with Renewable Electricity Generation – Technical Report*

National Renewable Energy Laboratory (NREL) (2013): T*he Value of Energy Storage for Grid Applications*

National Renewable Energy Laboratory (NREL) (n.d.): *Renewable Electricity Futures Study – Renewable Electricity Generation and Storage Technologies*

NPL (2011): *Methods for the Analysis of Trace-Level Impurities in Hydrogen for Fuel Cell Applications*

NRG Expert (2012): *Energy Storage – An Overview*

Ofgem (2014): *Electricity Balancing Significant Code Review – Final Policy Decision*

Pacific Northwest National Laboratory (2008): *Assessing the Value of Regulation Resources Based on Their Time Response Characteristics*

Pacific Northwest National Laboratory (2013): *National Assessment of Energy Storage for Grid Balancing and Arbitrage*

PIER Program (2011): *2020 Strategic Analysis Of Energy Storage in California*

PLANET – Planungsgruppe Energie und Technik GbR. et al. (2014): *Integration von Wind-Wasserstoff-Systemen in das Energiesystem*

REserviceS (2014): *European Case Study – Frequency Reserves from Wind Power and PV in a Large Footprint*

Sandia National Laboratories (2009): *Electric Utility Transmission and Distribution Upgrade Deferral Benefits from Modular Electricity Storage*

Sandia National Laboratories (2010): *Energy Storage for the Electricity Grid – Benefits and Market Potential Assesment Guide*

Sandia National Laboratories: *DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA*

SBC Energy Institute (2014): *Hydrogen-Based Energy Conversion*

SBC Energy Institute (2013): *Electricity Storage*

Store (2013): *European Regulatory and Market Framework for Electricity Storage Infrastructure*

SunEdison (2011): *Enabling the European Consumer to Generate Power for Self-Consumption*

Technical University Denmark (2013): *Energy Storage Options for Future Sustainable Energy Systems*

The Electricity Storage Network (2014): *Commercial and Regulatory Challenges of Implementing Smart Grid Solutions*

The Energy Research Partnership (2011): *The Future Role for Energy Storage in the UK*

THINK project (2012): *Electricity Storage – How to Facilitate its Deployment and Operation in the EU*, European University Institute

US Department of Energy (2013): *Grid Energy Storage*

US Energy Information Administration (EIA): *International Energy Outlook 2013*

US Federal Energy Regulatory Commission (2011): *Order No. 755*

US Federal Energy Regulatory Commission (2013): *Order No. 784*

Wagner, F. (2014): E*lectricity by Intermittent Sources – An Analysis Based on the German Situation 2012,* The European Physical Journal Plus

Glossary

CAES	compressed air energy storage
capex	capital expenses
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CE	Conformité Européenne
CPUC	California Public Utilities Commission
DG ENER	Directorate-General for Energy
DSO	distribution system operator
EC	European Commission
EEA	European economic area
EEG	Erneuerbare-Energien-Gesetz (German Renewable energy Act)
ENTSO-E	European Network of Transmission System Operators for Electricity
ES	electricity storage
EU	European Union
FCEV	fuel cell electric vehicle
FCH JU	Fuel Cell Hydrogen Joint Undertaking
FERC	Federal Energy Regulatory Commission
FIT	feed-in tariff
Flow-V	flow-vanadium
GHG	greenhouse gas
GW	gigawatt
GWh	gigawatt hour
High-RES	high renewable energy sources
ISO	independent system operator
kW	kilowatt
kWh	kilowatt hour
LAES	liquid air energy storage
LCoE	levelised cost of electricity
Li	lithium
Mt	million tonnes
NaS	sodium-sulfur
Ni	nickel
OEMs	original equipment manufacturer
opex	operating expenses
P2G	power to gas
P2P	power to power
Pb	lead
PEM	proton exchange membrane
PHES	pumped hydro energy storage
PV	photovoltaic
RES	renewable energy sources
RTO	regional transmission organisation
SMR	steam methane reforming
T&D	transmission and distribution
TSO	transmission system operator
TW	terawatt
TWh	terawatt hour
VRE	variable renewable energy
WACC	weighted average cost of capital