An Energy think tank informing the European Commission
INSIGHT_E

Policy Report
December 2015
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Business models for flexible production and storage

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This report is also available on our website: www.insightenergy.org

The INSIGHT_E project is funded by the European Commission under the 7th Framework Program for Research and Technological Development (2007-2013). This publication reflects only the views of its authors, and the European Commission cannot be held responsible for its content.

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Executive Summary

Current trends and policies are progressing in the direction of an increased share of electricity from renewable sources in the EU electricity system, in particular from intermittent sources such as wind and photovoltaics. Furthermore, the share of electricity in total energy consumption is likely to increase in the coming years. Finally, there is increasing use of electric appliances in households at varying use through the day. All together this results in potentially large and sometimes fast variation of both electricity production and consumption - as well as the need to match these - calling for temporary production or storage of electricity or conversion of electricity into other forms in a range of scales for both power and time.

The following research questions are the focus for this study:

- What lessons can be learnt from how flexible production and storage were applied in the past, also in terms of business models and legislation?
- How have business models and legislation in terms of flexible production and storage evolved to the present day in light of the increase in use of intermittent sources?
- What are the reasons for success or failure of flexible production and storage, particularly with regard to business models and legislation?
- What has the role of storage been in the energy system and how is it expected to change into the future, particularly in terms of the amount of energy, power needed and time scales?

In the light of past and current experiences, the study reviews the need for temporary production and storage (amount of energy, power needed, time scales) in the future, at a time horizon out to 2030 and 2050. This aspect of the report bases its analysis on modelling exercises, and considers the potential solutions to deploying temporary production and storage. Business models and potential evolutions of the legislative framework associated with the different solutions are also proposed.

As highlighted in the **past and present analysis of this study**, EU energy policy is mostly based on characteristics of existing generation assets (fossil fuel, nuclear and hydro), their ramping dynamics and start-up costs. So, far, flexibility has been provided from the generation supply side, and not demand side. It has been agreed by national regulators that the electricity grid supporting system flexibility should be designed up to the highest demand (peak demand) on the grid. However, the Energy Efficiency Directive leaves room for interpretation, where storage is envisaged as a demand tool.

Key learnings from the modelling study:

- The modelling study report verifies findings from other studies that multiple benefits are required to justify battery storage.
- There is a clear correlation between the degree of RES penetration and the value of storage. This is illustrated by the difference in feasibility of storage between the reference scenario and the CO_2 scenario.
- Under current estimations of battery prices, there is no business case for battery storage up to 2030. Storage becomes attractive in selected markets in 2050.
- There are large variations between the countries which were investigated: Austria, France, Germany and Italy. The main reason is the significant difference in production mix and infrastructure.

Further studies including how multiple benefits can be used to justify large-scale battery storage may be considered. However, it is likely that such studies would reveal even larger national differences.

Main findings of the report: The outlook for storage

- Ensuring a level playing field to competition. Flexibility depends on the liquidity of the market and would require a certain level of competition between the main players i.e. arbitrage between day-ahead and intraday markets, between peak and base load prices.

- Storage facilities should be generally understood as a semi-regulated activity, with the primary goals to serve the purpose of ensuring flexibility in the system while securing security of supply. Given the "semi-regulated" nature of storage, storage facilities should be owned by a separate body, a 'storage system operator', in line with the unbundling rules of the Third Package[1].

- Extensive research needs to be done on finalizing and establishing the needs and obligations of storage facilities in order to fulfill the foreseen role of storage facilities in a European electricity market, as well as securing communication between the 'storage system operators' and the grid system operators, the TSOs and DSOs.

[1] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0055:0093:EN:PDF

I. INTRODUCTION

Prior to the liberalization process of Europe's energy markets which began in the early 1990s, national electricity supply was mostly provided by a few, often vertically integrated, companies holding a legal monopoly on the entire value chain. Hence, the production or procurement, transmission or distribution and supply of electricity with regard to distinct areas were granted to single companies according to the predominant view in most EU Member States. It was evident that competition was not suitable due to the macroeconomic importance, the technical complexity, and the capital-intensive nature of facilities in the electricity sector (Heddenhausen, 2007). Electricity tariffs were generally fixed and revisited by the governments to enable cost recovery of investment and operation of the power plants and grid in the portfolio (Percebois, 2008).

During the 1990s, the European Union and the Member States decided the stepwise introduction of competition to electricity and gas markets. The first electricity and gas directives, adopted in the late 1990s, set a regulatory framework for power and gas industries and started the liberalisation process in the Member States. In order to promote the progress of the internal energy market further measures were considered necessary to enable the restructuring. Hence, the second gas and electricity directives, adopted in 2003, aimed at unbundling the energy transmission networks from the production and the supply side of the value chain. A third liberalisation package, proposed by the European Commission in 2007, targeted at removing shortcomings of the liberalisation progress and further strengthening the competitive environment.

However, in a number of Member States the liberalisation process is far from being complete. A recent report captures an overview of the current situation in Europe (Pye, 2015). The report indicates that in 2013, 19 of 28 Member States had begun the liberalisation process in the electricity market, while 20 of 28 Member States had begun liberalisation in the gas market.

In view of the above, power suppliers invested in power plant portfolios to meet the demand anticipated for all consumers in the supply region both securely and economically, taking into consideration legal and technical restrictions and the availability of fuels. According to Figure I-I the demand for electricity in Europe in the early 1990's was predominantly met by coal (including lignite) and nuclear power plants. Electricity generation from renewables was almost exclusively provided by hydro power plants.

Since the share of volatile feed-in from renewables was negligible, the need for flexibility[2] was mainly related to typical patterns of a group of residential, commercial and/or industrial power consumers. In this regard, fluctuations over the day, during the week and on a seasonal basis are observable within an electrical power system. Peak demand usually occurs in the day-time and off-peak in the night-time when domestic or commercial consumption is lower. Irregular events such as televised events or extreme weather can also lead to irregular changes in demand. During the week, the demand on weekdays generally exceeds the demand on weekend due to the share of commercial activities. Seasonal variations occur due to a higher demand in winter than in the summer.

[2] "Flexibility is the ability of a power system to maintain continuous service in the face of rapid and large swings in supply or demand (Papaefthymiou, Grave, & Dragoon, 2010)."

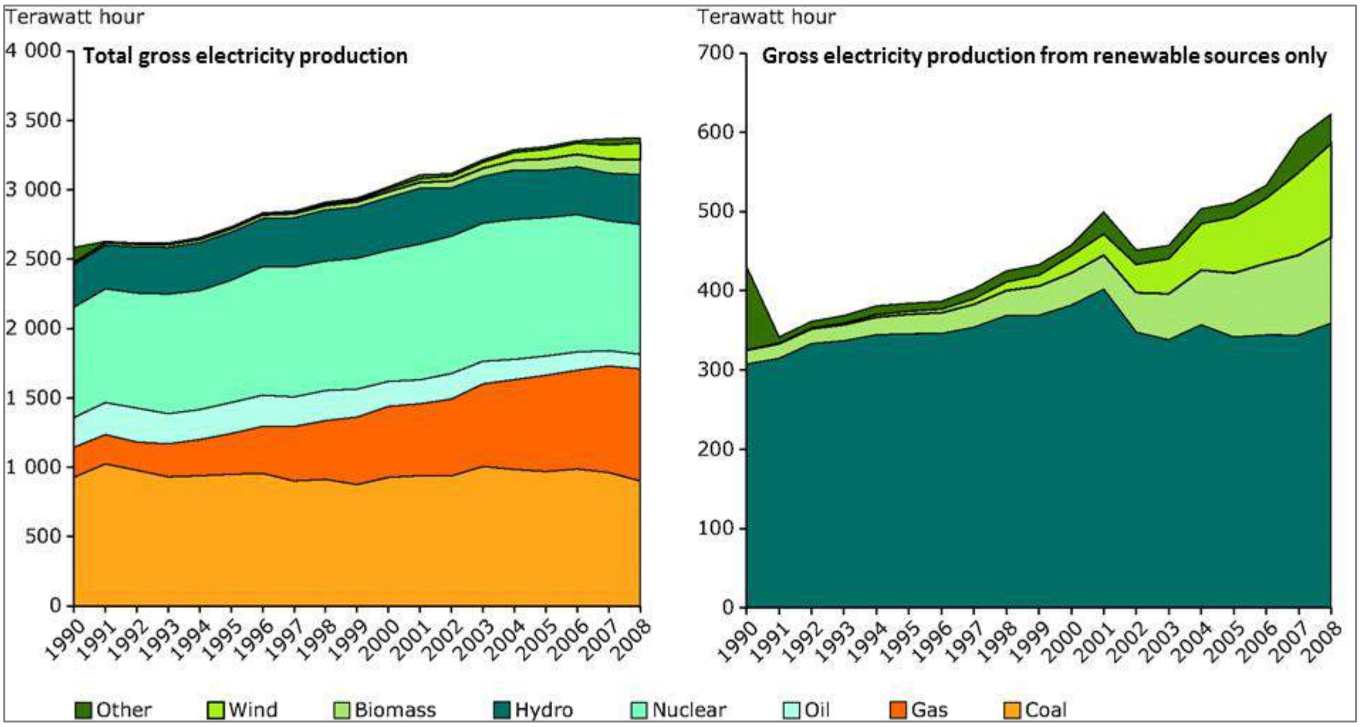

Figure I-I: Gross electricity generation by fuel in the EU 1990-2008. The figure on the right represents an enlargement of only the renewable sources from the figure presented on the left [3].

As indicated by Figure I-II, the residential, commercial and industrial sectors show different consumption patterns. The largest variance in consumption can be observed in the residential sector with the highest share of electricity used for cooling, heating and ventilation purposes compared with the other sectors. The industrial sector experiences little variability in electricity use. Within this sector economic variables, as well as technical operating conditions of heavy industries, affect industrial energy use rather than weather-related factors (U.S. Energy Information Administration (EIA), 2013).

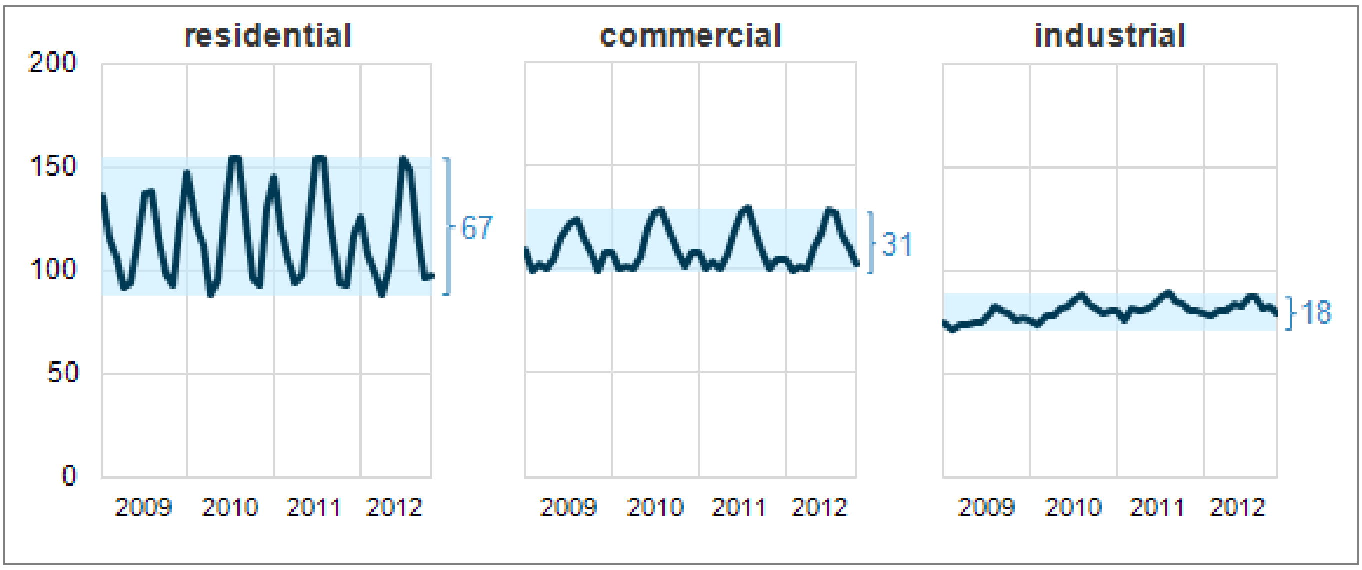

Figure I-II: Retail sales of electricity by end-use sector in billion kilowatt-hours in the US [5].

Regardless of the season, there is a surge in demand in the morning when domestic consumers start using electrical appliances or industrial companies begin operation. In the course of the morning demand stabilizes when shops open and electrical equipment, such as computers, are powered. Later in the day another surge occurs when the working day is over and people start to return home and switch on electrical equipment. In the course of the evening demand decreases to a minimum as people begin to retire to bed.

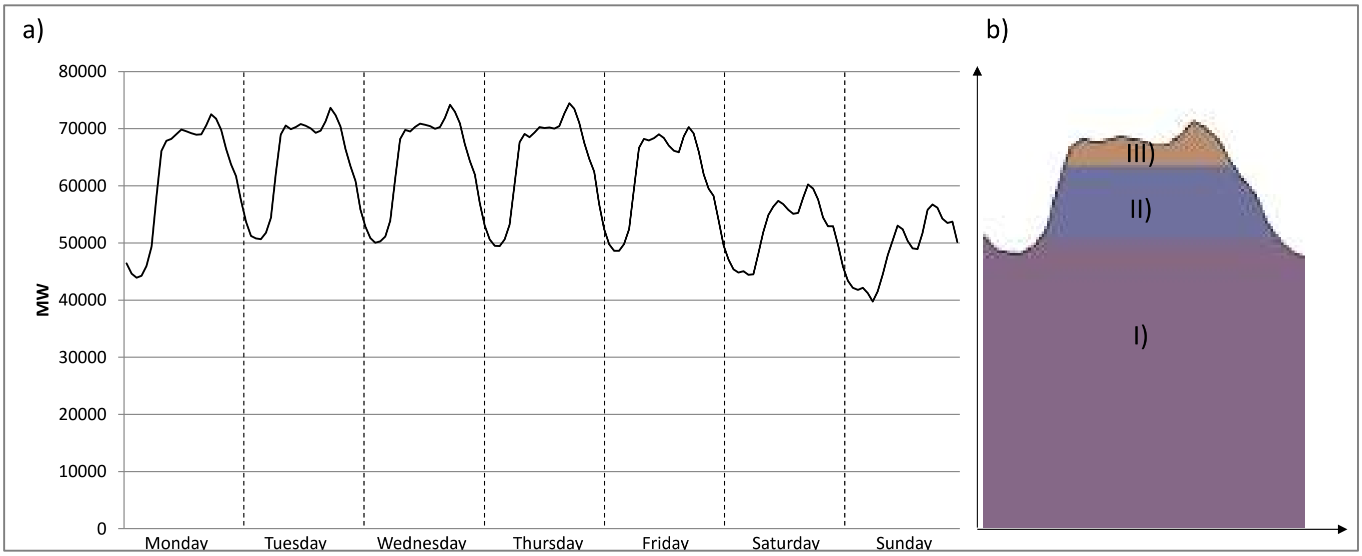

Figure I-III: (a) Hourly load curve of a sample European country during one week in winter, Data provided by [ENTSO-E], (b) Example of a hourly load curve on a weekday: Base load (I), Intermediate load (II), Peak load (III), diagram by author.

Power generators endeavour to balance the load plus losses throughout the grid and schedule the commitment of all units in their power plant portfolio at any time in order to minimize the overall cost of electricity generation. Following the schematic representation in Figure I-III (b) three types of power plants can be considered according to the cost-optimal duration of daily operation: base load, intermediate and peak load power plants. Base load units are designed to operate for long periods of time at or near full load as they have low operation costs due to use of low-cost fuels, supplying the basic demand on the network. This plant type is not optimized to respond to major shifts in output. A shutdown is only executed in case of forced outage and maintenance. For example, lignite, run-of-river or nuclear power plants can operate economically within this load range.

Table I-I presents an overview of the flexibility of the following various conventional power generating technologies: nuclear (NPP), hard coal (HC), lignite (LIGN), combined cycle gas (CCG) and pumped hydro storage (PS). As indicated in Table I-I, although technically suitable to perform load-following operations, the start-up of LIGN and NPP may take from several hours up to nearly two days (Delea & Casazza, 2010). As shown in Figure I-IV, the electricity generation in 1990 in many EU member states was largely based on NPP and LIGN subject to fuel availability. For example, the annual full load hours of NPP ranged from nearly 5200 in the UK up to almost 7800 in Belgium. Power generation from LIGN was considerable, particularly in Germany, reaching more than 6600 annual full load hours (Eurelectric, 2012).

Table I-I: Flexibility of conventional power generating technologies (Eurelectric, 2011)

	NPP	HC	LIGN	CCG	PS
Start-up Time "cold"	~ 40H	~ 6H	~ 10H	< 2H	~ 0,1H
Start-up Time "warm"	~ 40H	~ 3H	~ 6H	< 1,5H	~ 0,1H
Load Gradient ↗ "nominal Output"	~ 5%/M	~ 2%/M	~ 2%/M	~ 4%/M	> 40%/M
Load Gradient ↘ "nominal Output"	~ 5%/M	~ 2%/M	~ 2%/M	~ 4%/M	> 40%/M
Minimal Shutdown Time	←		NO	→	~ 10H
Minimal possible Load	50%	40%	40%	<50%	~ 15%

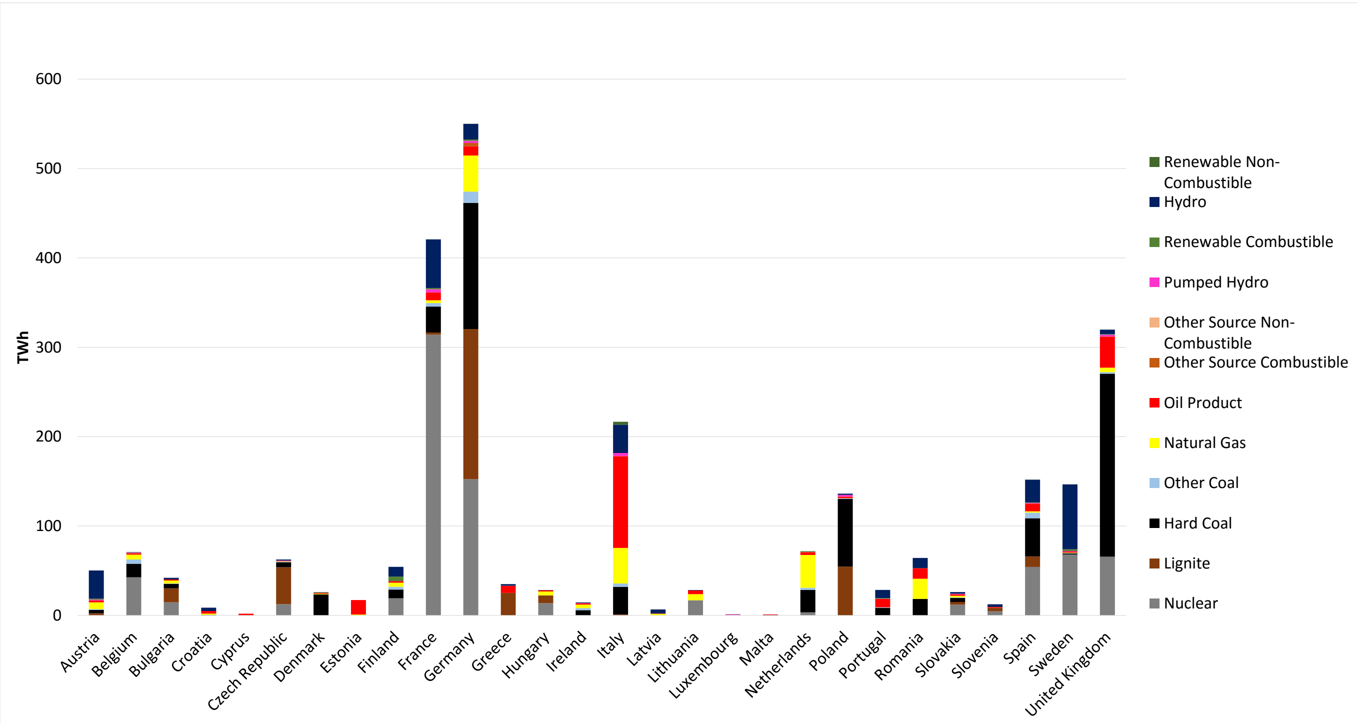

Figure I-IV: Gross electricity generation by fuel in 1990 in the EU-28, own representation based on data from (Eurostat).

Additionally, by-products in manufacturing processes served as "free" fuels for on-site electricity generation. Within steel production, large volumes of coke gas, blast furnace gas and converter gas are released and can be converted to electricity in gas turbines or engines. For example, per ton of coke that is produced from coal, approximately 470 Nm^3 of coke gas is produced, of which 40% can be used for power generation (Clarke Energy).

Demand in excess of the base load requires the use of further and more flexible capacities. Power plants in the range of intermediate load start up in the morning to meet the surge in demand and shut down in the evening when demand begins to fall again to the base load level (Breeze, 2005). Usually HC and CCG units are used to meet the intermediate load. These power plant types are designed for frequent partial-load operations and daily start up and shutdown routines (Strauss, 2009).

As shown in Table I-I, HC and CCG units can be brought online more quickly and can additionally dispose of fast load gradients up to 2%/min. As illustrated by Figure I-IV, HC power was of high importance for intermediate load generation, particularly in Denmark and UK, amounting to annual capacity factors of 49% and 59%, respectively (Eurelectric, 2012). The generation from HC in Denmark in 1990 accounted for more than 90% of total power generation, indicating that HC power plants were also deployed for base load generation (Eurostat).

Peak load units are necessary to cover sudden peaks in demand that occur at specific, generally predictable hours of a given period (i.e., the peak load in the evening, when consumers simultaneously switch on electrical equipment). In addition, peak load units provide ancillary services and flexibility to the power system in case of forced power plant outages or sudden and unexpected rise in demand. Gas and oil-fired turbines, reciprocating engines and storage units comprise the majority of peak load power plants, as they are able to start up from a cold condition within minutes and show higher responsiveness than intermediate load power plants (Delea & Casazza, 2010).

As shown by Figure I-IV, almost every country in the EU-28 operated gas- and/or oil-fired generation plants in 1990, providing peak power and flexibility to the power system. For example, electricity generation from natural gas accounted for more than 50% in the Netherlands. Natural gas power stations ran on average nearly 3500 full load hours in 1990. As with coal in Denmark, the high share of oil-based power generation in many countries in 1990 (Cyprus: 100%; Estonia: 94%; Italy: 47%) indicates that oil was also used for intermediate-load generation (Eurostat) (Eurelectric, 2012).

II. Role of storage

II.A. Past role of energy storage: which technologies were used and why?

Against the background of the discrepancy between customers' requirements and production, resulting in peak and off-peak periods, electric energy storage (EES) systems provided additional flexibility to the system and allowed electricity production to be uncoupled from its supply to consumers. As indicated, pumped storage (PHS) is the most responsive of the technologies, able to generate electricity almost instantaneously when called upon. This plant type also has the highest load gradient, where ramp up and down by more than 40% of the nominal output per minute is possible. In fact, the prevailing opinion in the past, during periods of high consumption growth with no particular obstacles to developing pre-existing supply networks, was that there was no economically satisfactory solution for storing electrical energy. According to the data in Figure I-IV, the share of pumped hydro storage in gross electricity production in 1990 was negligible - except for Luxembourg where over half of the generation came from the pumped hydro storage plant in Vianden. However, a slowdown in growth and improvements of storage technologies have resulted in applications for EES along the entire electricity value chain (Levillain, Serres, Chantelou, Bonety, & Marquet, 1999).

II.A.1. Generation

Overproduction during off-peak periods was stored and released to provide peaking power, resulting in lower peak production costs and a more uniform load factor for generation, transmission, and distribution systems. Base load power plants, operating near full capacity for economic reasons, were prevented from ramping (thereby improving efficiency of the overall generation and reducing emissions). Additionally, EES could participate in load-following operation and could be considered for standby and spinning reserve in case of power station outages. Due to their "black start"[3] capability EES can replace an electric power station. In the long-term, excess capacities for peak demand can be reduced by operating storage technologies. As illustrated by Figure II-I sufficient capacities of EES would enable thermal generating capacities to only meet average demand rather than peak demands, provided that the electricity price spread between peak and off-peak times is sufficiently high.

[3] A **black start** is the process of restoring an electric power station or a part of an electric grid to operation without relying on the external transmission network. Normally, the electric power used within the plant is provided from the station's own generators.

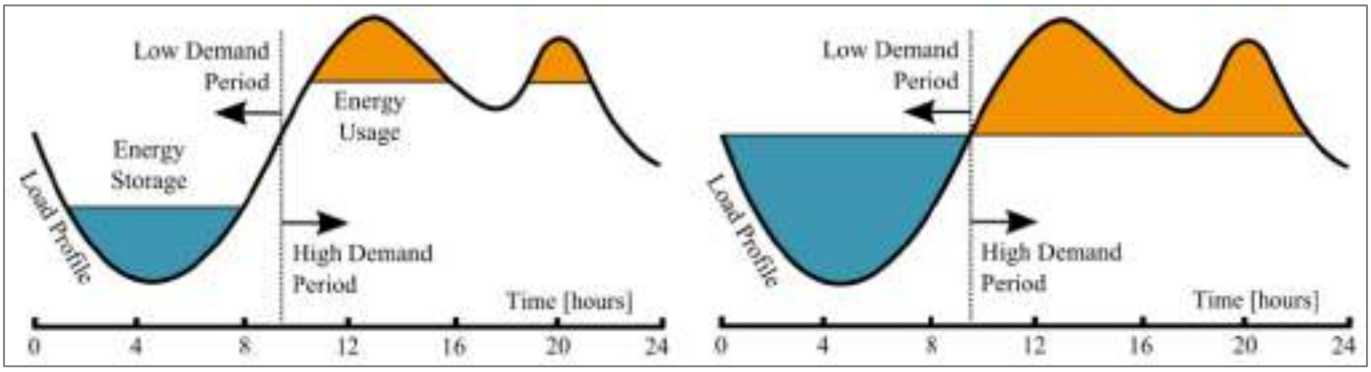

Figure II-I: Load profile of a large-scale electricity storage system. (a) EES in Peak Shaving; (b) EES in load levelling (Sabihuddin, Kiprakis, & Mueller, 2015 8 (1)).

II.A.2. Transmission and distribution

Frequency shifts in power networks occur mainly due to random short time demand changes. For example, irregular events such as televised events or extreme weather can lead to irregular changes in demand. Frequency deviations may also result from the supply side, e.g. by unscheduled power plant outages resulting in a drop in frequency or the feed-in from VRES. In the case the network frequency falls below a certain threshold, consumers must be disconnected (load-shedding) from the network in order to maintain the grid stability. Thus, the frequency within a power network must be kept within tight tolerance bounds. Frequency regulation is an important service in order to maintain security of power supply. Historically frequency regulation was mainly provided by ramping of generation units. Similarly, EES were able to adapt the charging and discharging process according to the needs of the transmission system. As for frequency, the voltage in a power system must be kept within tolerances. More precisely, reactive power[4] needs to be balanced to prevent voltage to rise and drop across the power network. As an alternative to thermal generation units, EES could also provide voltage control. Further benefits could be obtained by operating storage technologies when the carrying capacity of the transmission and distribution systems was likely to overload temporarily. Instead of adding small and economically unviable amounts of extra capacity, a small amount of energy storage could help reducing peak load and lowering the load of the transmission and distribution system.

II.A.3. Energy services

Besides power plant and power network operators, end-users have also taken advantage of power storage. Customers having opted for a relevant retail tariff, incentivizing electricity consumption during off-peak periods as a result of lower electricity prices in many Member States. For example, with electric night storage heaters as one early form of demand side management in the residential

[4] Reactive power is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage.

sector, demand for electricity was shifted to off-peak time to be released as heat in peak-times, thereby avoiding power plants from ramping and balancing load profiles.

As shown in Figure II-IIa different types of electrical energy storage systems can be distinguished according to the energy form used: mechanical, electrochemical, chemical, electrical and thermal. However, some technologies in the figure are still under development or a long way from market maturity. For a brief description of specific technologies see (International Eletrotechnical Commission (IEC), 2011). In Figure II-IIb the technology options are compared by the rated power, the energy content and the nominal discharge time, covering a wide spectrum from seconds to month. This includes applications ranging from larger scale, generation and transmission related systems, to those 'beyond the meter', into the customer/end-user site including portable devices, transport vehicles and stationary energy resources.

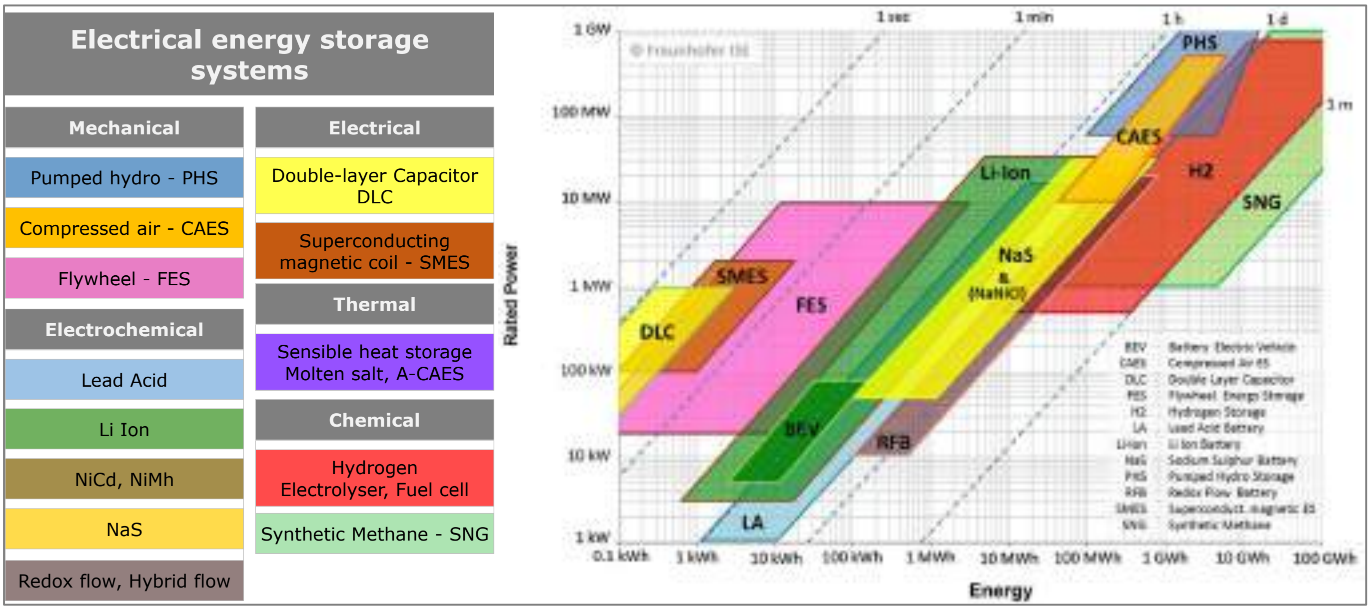

Figure II-II: Classification of electrical energy storage systems according to energy form (a); Comparison of rated power, energy content and discharge time of different EES technologies (b), own representation based on (International Eletrotechnical Commission (IEC), 2011).

From the storage options shown above, hydropower storage plants are the only large-scale storage technology available to date, providing the most efficient and economical way to store potential electricity. PHS utilities usually offer a short- to medium-term storage capacity depending on the size of the reservoir while conventional storage hydropower plants with natural inflow are capable to offer significant long-term storage capacity (Pedraza, 2015). The operation of PHS has been essential in the past, when Europe's networks were mainly composed of a large number of regional grids with very weak interconnections (European Commission, 2013). Except for hydropower, other storage technologies - such as battery and flywheel storage - used to be very rare and not efficient due to either inappropriate infrastructure or economic reasons (Levillain, Serres, Chantelou, Bonety, & Marquet, 1999).

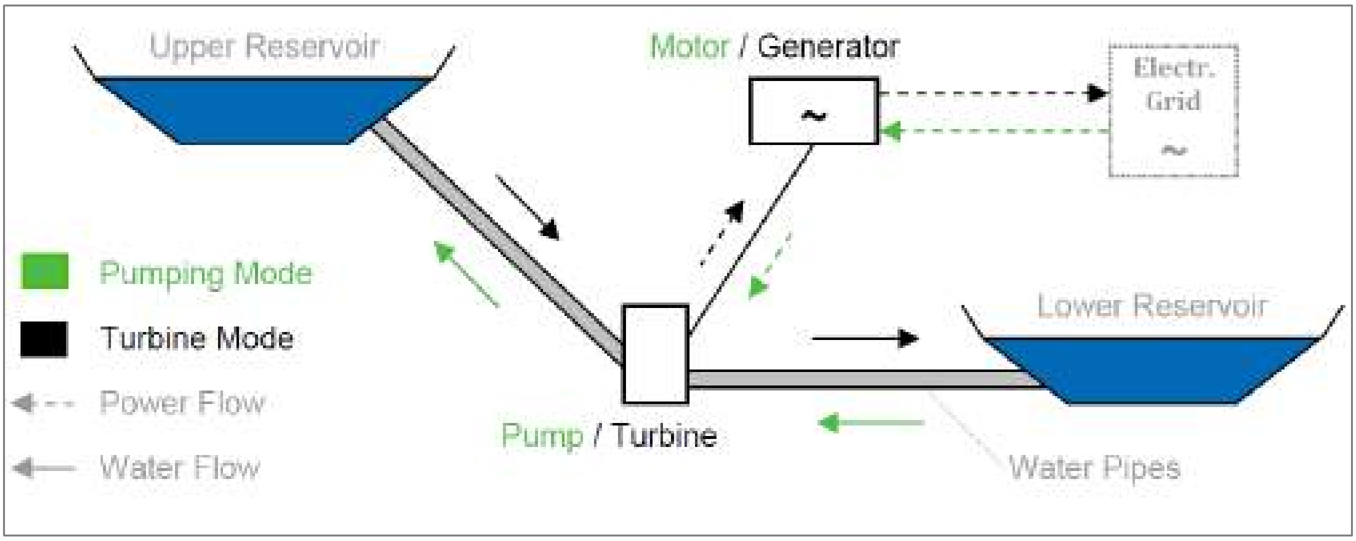

Figure II-III: Simplified schematic of PHS system[5]

II.A.4. Pumped Hydro Storage

Pumped hydro storage is currently the only commercially proven, large-scale, economically viable (>100 MW) energy storage technology. The fundamental principle of this storage type is to store electric energy in the form of hydraulic potential energy. Water stored in an upper reservoir is processed in a turbine to recover its potential energy in form of mechanical (kinetic) energy.

Figure II-III shows a simplified schematic of a general PHS system but there are many different subtypes of PHS. For example, there is sea water PHS, which use the ocean as a lower reservoir (one system currently exists in Japan), or underground PHS, which use deep mining structures for one or both reservoirs, although these systems are still at a conceptual stage and are not mainstream. Generally two main types of PHS are distinguished, namely pure PHS (PHES) and pump-back PHS (Deane et al., 2010). Pure PHES plants rely entirely on water that has been pumped to an upper reservoir from a lower reservoir, a river or the sea. Pure PHES are also known as 'closed-loop' or 'off-stream'. Pump-back PHS use a combination of pumped water and natural inflow to produce power/energy similar to a conventional hydroelectric power plant. Pump-back PHS may be located on rivers or valleys with glacial or hydro inflow.

PHS systems are among the oldest and most widely used energy storage options and therefore fully commercialized. Some of the earliest PHS plants were built in the Alpine regions of Switzerland and Austria, regions that have a rich hydro resource and a natural complimentary topography for PHS. PHS development on a European level is closely correlated to nuclear development. However, countries such as Austria with no nuclear generation, but a rich hydro resource, developed PHS to primarily enhance the operation and efficiency of large-scale hydro power plants.

The chronological development of PHS in many countries shows the majority of plants were built from the 1960s to the late 1980s (Figure II-IV). This was in part due to a rush for energy security and

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[5] Source: http://www.store-project.eu/

nuclear energy after the oil crises in the early 1970s. Fewer facilities were developed during the 1990s; due to a natural saturation of the best available (and most cost effective) locations and a decline in growth in nuclear development.

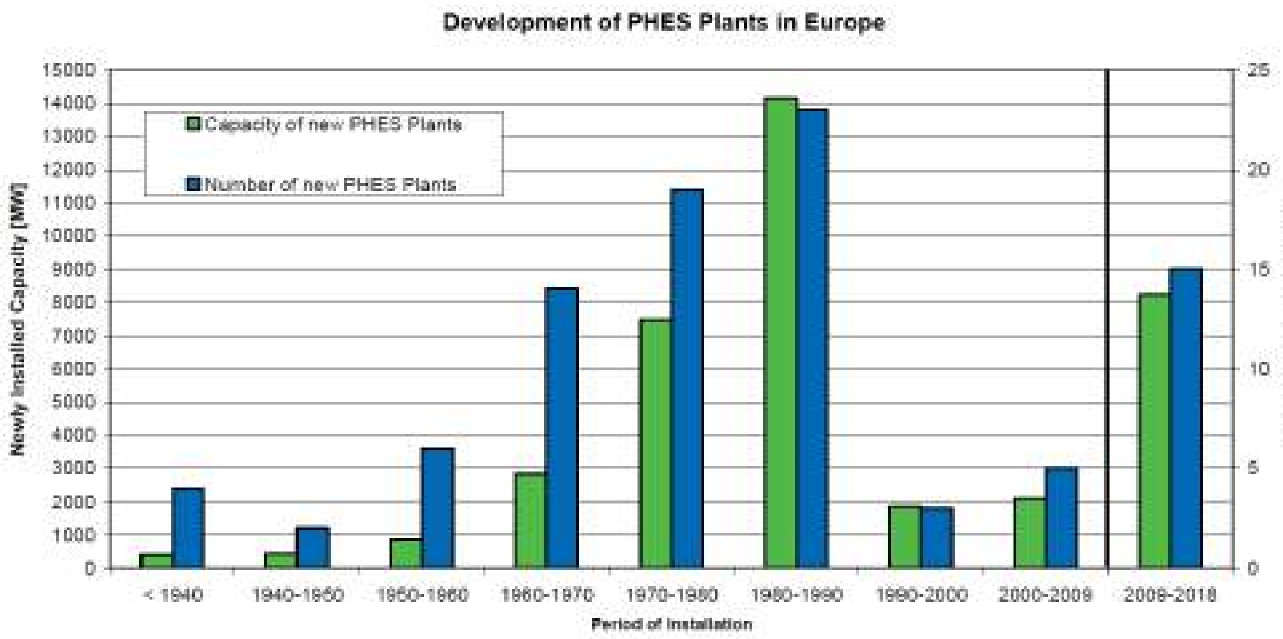

Figure II-IV: Chronological development of PHES in MW capacity and plant number in the EU for existing and proposed PHES. Source www.store-project.eu

The hydraulic, mechanical and electrical efficiencies of pumped storage determine the overall cycle efficiency, ranging from 65 to 85%. Power ratings of PHS systems range from several MW up to 2 GW with discharge times up to 100 hours depending on the storage volume of the reservoirs (see Figure II-IIb). Pumping and generating in PHS systems generally follow a daily cycle but weekly or even seasonal cycling is also possible with larger PHS plants.

II.A.5. Other storage technologies

Other mechanical storage systems have not yet significantly penetrated the energy market. Experience with compressed air energy storage (CAES) is limited. Diabatic[6] and advanced adiabatic CAES (A-CAES) can be distinguished. Worldwide only two diabatic CAES utilities are operated to date, of which the first was built in 1978 in Germany, with a capacity of 290 MW (Huntorf). Adiabatic systems promising higher efficiencies and zero direct CO_2 emissions were not available (Swider, 2007). The main drawback of this storage type is the need for suitable geological structures. The construction of artificial caverns for storage would involve high cost (European Association for Storage of Energy (EASE); European Energy Research Alliance (EERA), 2013). Although flywheel storage is a mature technology and fully introduced in the industrial market (i.e. motion smoothing, ride-through power

[6] In a diabatic CAES, air is cooled before compression and reheated before expansion in a gas turbine. In an adiabatic CAES, the air's heat energy is stored separately and recovered before expansion (Swider, 2007).

for power disturbances), it is not competitive at the higher power ratings[7]. High maintenance requirements and installations regarding safety lead to increased costs (Cole, Hertem, Meeus, & Belmans).

Electrochemical storage, such as Battery Energy Storage (BES), being available in various sizes and power ratings has not competed with PHS or CAES in the period prior to liberalization due to limited lifetime and storage capacities as well as higher maintenance requirements. Furthermore, concerns existed about negative environmental impact caused by batteries due to toxic materials (Cole, Hertem, Meeus, & Belmans).

Chemical storage via hydrogen is not competitive with other storage technologies. Notably high costs and very low efficiency have prevented the large-scale introduction. With hydrogen only being available as a secondary source of energy, costly conversion equipment is necessary. The conversion process has high energy consumption resulting in a fairly low overall efficiency. Furthermore, the volumetric energy density is very low, requiring much space for storage and increasing the cost of infrastructure (Cole, Hertem, Meeus, & Belmans).

Supercapacitors (Double-Layer Capacitors (DLC)) and Superconducting Magnetic Energy Storage (SMES) as new options for electrical energy storage are not yet at a stage of development for market introduction (Cole, Hertem, Meeus, & Belmans).

Thermal storage has been in use since the 1960s in terms of night storage heaters in order to utilize surplus power generation at night. With the growth of nuclear energy, it became popular in the 1970s (European Commission, 2002). According to Table II-I, night storage heaters were predominant in the UK, Germany and France. In the UK 8% of households used storage heaters. In France 22% of households used central heating of which 20% was supplied by storage heaters (European Commission, 2002). From 1970 to 1996 the installed capacity of night storage heaters in Germany rose from 10 GW to almost 40 GW, at a consumption level of 27 TWh of electrical energy. For comparison, pumped hydro storage in Germany without natural inflow produced 3.7 TWh in 1996 (Stadler, 2008).

Table II-I: Penetration of heat emitter types used in electric central heating in 1998, absolute percentages of households (European Commission, 2002).

%	Denmark	Finland	France	Germany	Ireland	Sweden	UK
Storage			4.44	6.1			8
Convective			16.9			12.9	
Hydronic						6.5	
Other (incl. radiant panels)			0.9	0.1			2
Total	0.7	21.2	22.2	6.5	8.8	19.4	10

[7] The first flywheel energy storage plant is expected to launch commercially in 2017 (First Hybrid Flywheel Energy Storage Plant in Europe announced in Midlands, 2015)

In addition, and of higher importance for the domestic heat supply, electric water heaters were a widespread application of thermal storage. The total EU electricity consumption by domestic electric storage water heaters in 1997 was 87 TWh accounting for 15% of the overall household electricity consumption. About 30% of the EU's 142 million households in 1997 used electric water heating systems. Especially in Austria, France, Germany and Luxemburg water heating systems were very common (> 40%[8]). This type of heat supply was also popular in Italy, Belgium and Finland (>30%[8]), in the UK (>20%[8]) and to a lower extent in Portugal, Sweden, the Netherlands, Ireland, Denmark and Spain (>10%[8]). In Greece, less than 10% of all households made use of electric water heaters as their hot water source (European Commission, 1998).

[8] Referring to all households.

II.B. Present role of energy storage

Due to the liberalization of the European electricity markets in 1996, 2003 and 2009, new regulatory policies for electricity generation from renewable energy sources (RES) appeared on the political agenda in most of the EU Member States as well as on the EU level. In particular, the European Commission has strongly encouraged ambitious targets and support schemes for a large scale market penetration of renewable energies (Kühn, 1990). Between 1990 and 2013, total electricity generation from RES increased by 177%. The most significant growth has been in distributed variable RES (primarily generation from wind and solar). In 2013, electricity generation from RES in the EU-28 reached 854 TWh, 37% of which was from wind and solar power. The quantity of electricity generated from wind turbines has more than tripled in the period between 2005 and 2013. Solar power generation has grown considerably and increased 55-fold in the same period. As illustrated by Figure II-V significant amounts of wind and solar generation had to be integrated into Europe's electricity system, especially in Germany, Spain, Italy, and UK.

Due to uncertain weather conditions, the amount of wind and solar power in the system cannot be predicted with accuracy. In fact, the generation is subject to daily and seasonal fluctuations. Consequently, in addition to demand-driven fluctuations due to consumer behaviour the growing amount of variable renewable energy sources has led to generation-driven fluctuations increasing the challenge of keeping the electricity system in constant balance and the need for adequate infrastructure to integrate the varying output. As long as the share of variable RES in a power system is low the system can operate as usual (Eurelectric, 2011). More precisely, when the share of variable RES is lower than 15% to 20% of the overall electricity consumption, the grid operators can compensate the intermittency. However, the large growth of RES has led to a situation where the generation share exceeds 20-25% at times, a situation that some European countries, such as Denmark (43.1%), Spain (36.4%) and Germany (25.6%), are facing today (European Commission, 2013).

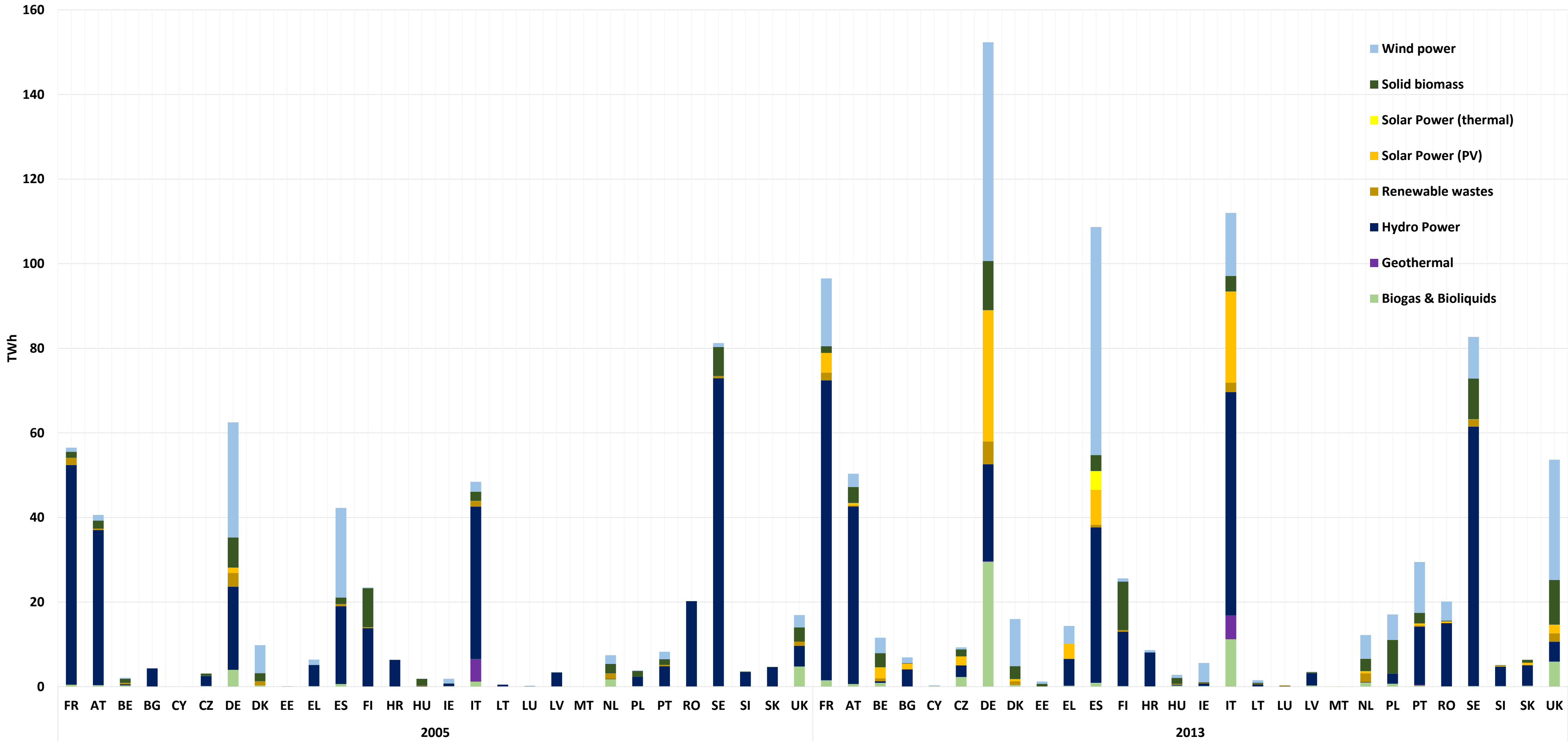

Figure II-V: Gross electricity generation from renewable sources in the EU-28 by country and share of intermittent generation (solar and wind) in gross electricity consumption, own representation on the basis of data from (Eurostat).

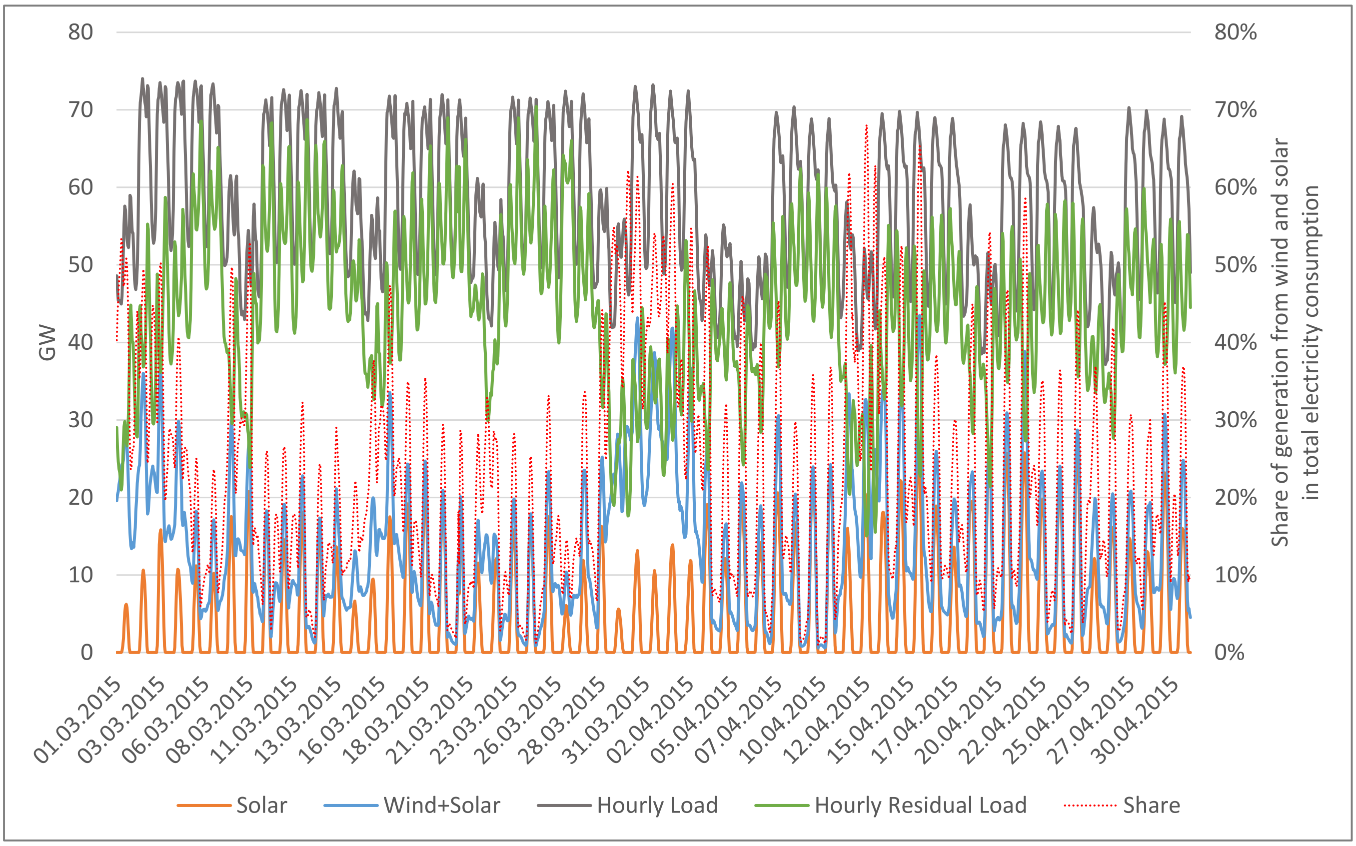

Figure II-VI: Hourly load, wind and solar generation in Germany, own representation based on data provided by (European Network for Transmisson System Operators for Electricity (ENTSO-E)), (Tennet TSO GmbH), (Amprion GmbH), (50Hertz Transmission GmbH), (TransnetBW GmbH).

Figure II-VI illustrates such a situation using hourly network figures of the German transmission grid from March to April 2015. The share of wind and solar generation in total electricity consumption exceeded at least 30% in 442 hours and a share of 50% in 92 hours. At times, a share above 65% was reached. In contrast, for more than 100 hours' wind and solar generation contributed less than 5% requiring the remainder of the power generation portfolio to meet the demand. As a result, the residual load was subject to considerable fluctuations. While the hourly load in the considered period increased at a maximum of 18%, which was reasonably foreseeable due to a regular surge in demand, the morning fluctuations of the hourly residual load were significantly higher due to less accurately predicted feed from wind turbines and PV systems. Hereby, a maximum value of more than 35% was reached corresponding to a power request of nearly 10 GW within one hour. As shown in Table II-II other countries in Europe are faced with similar challenges; regional fluctuations from wind power can reach considerable sizes, especially in Denmark and Ireland.

Table II-II: Short-term variations of large scale regional wind power, as percent of installed wind power capacity, for different time scales and regions[9] (European Wind Energy Association (EWEA), 2010).

			10-15 minutes		1 hour		4 hours		12 hours	
Region	Region size	Numbers of sites	Max decrease	Max increase	Max decrease	Max increase	Max decrease	Max increase	Max decrease	Max increase
Denmark	300x300 km²	> 100			-23%	+20%	-62%	+53%	-74%	+79%
West-Denmark	200x200 km²	> 100			-26%	+20%	-70%	+57%	-74%	+84%
East-Denmark	200x200 km²	> 100			-25%	+36%	-65%	+72%	-74%	+72%
Ireland	280x480 km²	11	-12%	+12%	-30%	+30%	-50%	+50%	-70%	+70%
Portugal	300x800 km²	29	-12%	+12%	-16%	+13%	-34%	+23%	-52%	+43%
Germany	400x400 km²	> 100	-6%	+6%	-17%	+12%	-40%	+27%		
Finland	400x900 km²	30			-16%	+16%	-41%	+40%	-66%	+59%
Sweden	400x900 km²	56			-17%	+19%	-40%	+40%		

Generally, the coincidence of increasing generation from variable RES and reduced demand, for example at the beginning of a weekend, and the opposite at the beginning of the week can lead to extreme power ramps. Such short-term and extensive requests for power impose new requirements for dispatchable generation[10] facilities (Eurelectric, 2011). This underlines that in addition to continual improvements of accuracy of forecasts more flexibility and back-up resources are necessary to cope with an increasing share of non-dispatchable RES in the energy mix of the EU member states. All flexibility sources need to be assessed in terms of their ability to integrate RES volatility and optimize the energy system as regards security of supply and affordability. The role of storage and flexible generation must be reconsidered in this context.

Figure II-VII gives a schematic overview of the options to meet the growing need for flexibility in the electricity market covering the categories supply, demand, storage, and the transmission/distribution system.

Flexibility options in power supply include dispatchable centralized and distributed power generation but also variable RES as controlled curtailment plays a role in meeting power system flexibility. In contrast, consumers willing to shift their power demand in favour of network requirements can provide additional flexibility taking advantage of new applications in communication and control, enabling a two-way communication. In addition to the suitability of energy storage facilities to provide demand-driven peak energy and balancing to the grid, energy storage helps to remove electricity from the system in times of over supply from variable RES for subsequent use in a period of under supply (temporal compensation). The expansion and modernization of power transmission and distribution networks are a “key enabler of flexibility” in the system allowing the exchange of regional over-supply thereby alleviating local network congestion (spatial compensation). Furthermore increasing the

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[9] Denmark, data 2000-2002 from http://www.energinet.dk; Ireland, Eirgrid data, 2004-2005; Germany, ISET, 2005; Finland, years 2005-2007 (Holmgren, 2008); Sweden, simulated data for 56 wind sites 1992-2001 (Axelsson et al., 2005); Portugal, INETI.

[10] Dispatchable generation refers to sources of electricity that can be dispatched at the request of power grid operators or of the plant owner; that is, generating plants that can be turned on or off, or can adjust their power output accordingly to an order

capacity of network lines can provide access to spatially distributed flexibility resources (Papaefthymiou, Grave, & Dragoon, 2010). In addition, cross-sectoral storage is a further option to deal with fluctuating input by using power-to-X technologies – for example by coupling the electricity and heating sectors in the form of heat accumulators (power-to-heat). As a result, distributed cogeneration plants can focus on electrical power generation, thereby reducing the proportion of must-run plants. Accordingly, further cross-sectoral technologies such as power-to-gas and power-to-mobility (electric vehicles) in the transport and chemical sector could in the future enable additional flexibility for the electricity system (Agora Energiewende, 2014).

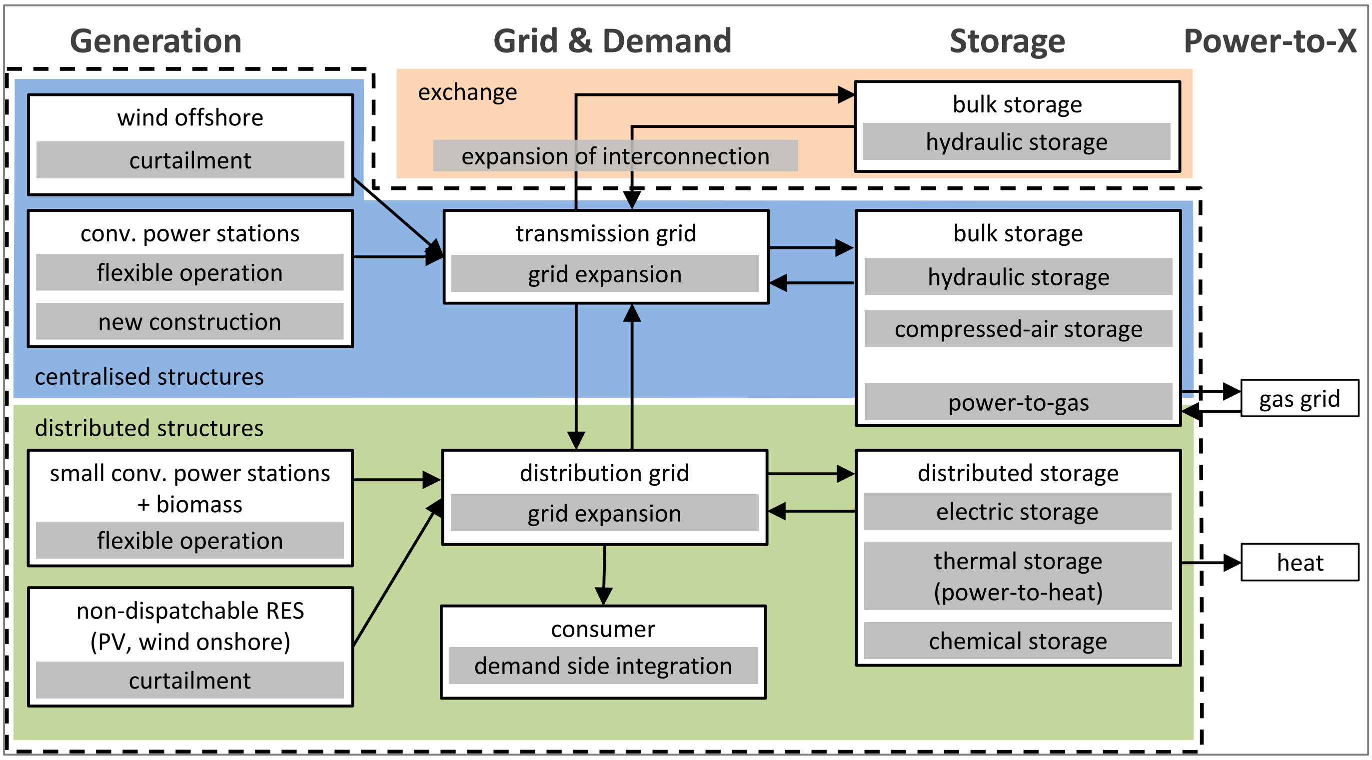

Figure II-VII: Flexibility options in the electricity market (Hufendiek, 2015).

Along with regional availability, the use of the different flexibility options conforms to the operational timeframe. In this respect, several flexibility options are possible. Figure II-VIII gives a summary of the suitability of different flexibility options highlighting the major barriers for their deployment subject to operational timeframes: **short-term** flexibility (up to one hour), **mid-term** flexibility (up to days), and **long-term** flexibility (seasonal variations).

(Red: small-scale distributed technologies; **Bold, underlined:** Mature technologies)

Figure II-VIII: Comparative assessment of the characteristics of flexibility options in different operational timeframes (Papaefthymiou, Grave, & Dragoon, 2010).

The most mature options are on the supply side, particularly open cycle turbines (OCGT) and internal combustion engines (ICE), which can provide short term flexibility. Cold start times and ramping capabilities are limiting factors to the suitability of other plant types (see Figure II-VIII). Main options for mid-term flexibility in the supply side are flexible coal, gas-fired plants and ICE plants. Of course, in terms of greenhouse gas emissions, flexibility from storage facility using 'green' electricity performs better. The use of CHP plants is restricted to thermal storage and primary operation constraints. Active power control (APC) of variable RES (VRES) can contribute to mid-term flexibility.

On the demand side, large-scale industrial demand response (DR) is a mature option to provide short and mid-term flexibility. Small-scale applications would require a suitable IT infrastructure and raises the question of data management.

II.B.1. Pumped Hydro Storage

On the storage side, pumped hydro is the primary mature technology to provide short and mid-term flexibility. More recently, there has been a renewed interest in the technology as an integrator for variable wind power.

Most capacity is located in mountainous areas (Alps, Pyrenees, Scottish Highlands, Ardennes, and Carpathians). Currently there are more than 90 GW of PHES systems (with power rating >100 MW) installed worldwide, representing approximately 3% of global generation capacity. No official figures are available for the total installed capacity of PHES in the EU. The European Market for Pumped Storage Power Plants (Ecoprog) put total capacity at almost 45 GW in the beginning of 2011.

Germany has the largest number of PHS plants with 23 operational plants ranging in capacity from 62.5 MW to 1,060 MW. Germany is second only to Spain in terms of installed MW capacity. Over 6,000 MW of PHS is installed on the Iberian Peninsula. Spain has 14 PHS plants with sizes ranging from 65 MW to 745 MW, the largest plant being the Iberdrola-owned Villarino plant. Portugal has five major PHS plants with an average capacity of 160 MW. PHS in Portugal and Spain are predominantly pump-back type operating on major rivers or operating as part of larger hydro complexes or cascades. This type of facility can also play a number of important roles from irrigation to flood control. The largest PHS plant in the EU is the 1,800 MW EDF owned 'Grand Maison' facility in the French Alps opened in 1987. The 1,728 MW Dinorwig plant in the UK was previously the largest PHES plant in Europe. Dinorwig can achieve full load from spinning in less than 20 seconds.

Worldwide, the USA and Japan have the highest installed capacities of PHS. In the USA, there is an installed capacity of approximately 22 GW, accounting for approximately 2.1% of total installed generating capacity. Like the USA, Japan developed PHS to complement nuclear power facilities, providing peak power in the evenings and pumping when demand is low.

II.B.2. Case studies: which storage technologies were used where, why and how much?

II.B.2.i Germany

The spread between the maximum and minimum values of the residual load (the difference between load and variable RES feed-in) is one indicator for the flexibility needed in a power system. The gradient of the load ramp is another. In Germany, the residual load varied between 18 and 77 GW in 2013. In the same year hourly ramps occurred of up to +15 GW and -10 GW (Agora Energiewende, 2015).

The flexibility needed in the German power system is currently provided widely by the domestic power generation portfolio. Since many of the existing thermal power plants were constructed in the 1980s and 1990s before variable generation from wind and solar became significant, measures have been taken to improve the flexibility of these power plants. Today, base load power plants that are not capable of flexible operation are barely represented in the overall electricity generation mix. Recently built power plants are designed for flexible operation. Figure II-IX illustrates a situation in the recent past where due to a regular surge in demand in the morning and a simultaneous decrease of wind supply a large requirement for additional dispatchable capacity occurred, amounting to 45 GW within eight hours. The gap was almost completely closed by coal (including lignite) and gas power plants. Lignite and coal power plants provided nearly 75% of the flexibility needed. Low variable cost nuclear power plants can operate flexibly within certain limits (see Figure II-IX) but are ramped only if flexibility reserves from fossil fuel generation are already exploited (Lambertz, Schiffer, Serdarusic, & Voß, 2012).

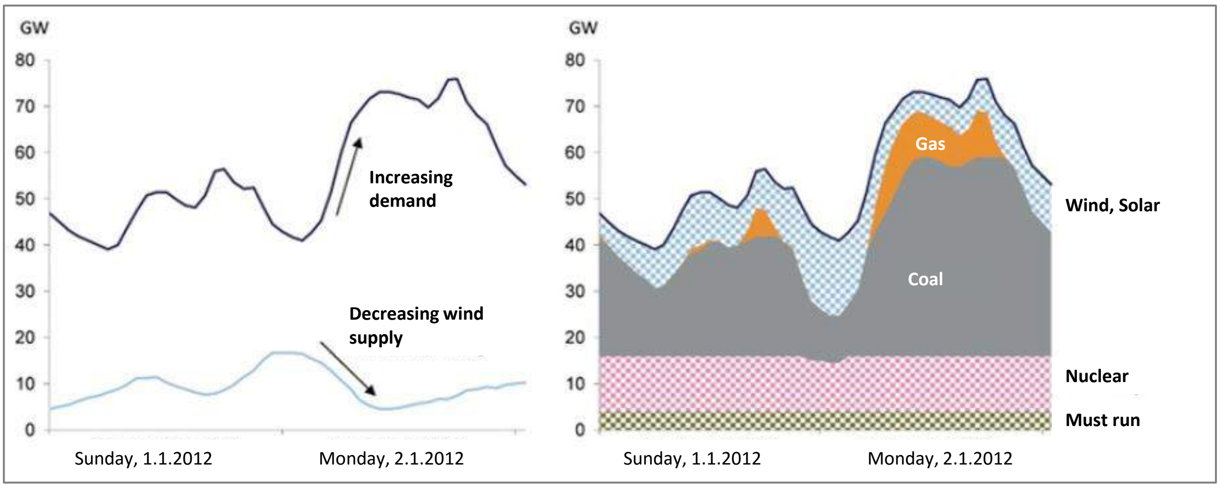

Figure II-IX: Electricity demand, wind supply and unit commitment in Germany on January 1, 2 2012[11] (Lambertz, Schiffer, Serdarusic, & Voß, 2012).

In the short term, electricity storage fills the gap between the ramping down time of wind and solar and the ramping up time of back-up plants. In this case, additional flexibility for the German power system was provided by pumped hydro storage facilities (European Commission, 2013). As shown by Figure II-X Germany together with France, Spain and Italy operates pumped-storage facilities exceeding 5000 MW. Further capacities amounting to 3 GW come from Luxembourg and Austria but are directly connected to the German transmission network (Schill, Diekmann, & Zerrahn, 2015). Besides Germany, seven countries in Europe have obtained licenses to build new pumped storage power plants. Hereafter, an additional capacity of 1.7 GW is planned, while an additional capacity of 194 MW is in an early planning stage (no license yet) (Eurelectric, 2011).

II.B.2.ii Scandinavia

Sweden, Norway, Finland and Denmark are integrated in a well-functioning electricity market (Nord Pool) and also have well-established cross-border cooperation mechanisms between TSOs. More than half of the annual power generation is sourced from hydro, 20% from nuclear, 15% from fossil fuels and the rest from other sources. Although, according to Figure II-X no significant pumped hydro facilities are operated, Scandinavia has considerable reservoir storage capacities at its disposal - more than one third of the annual generation capability (120 TWh on a seasonal basis). Along with a large flexible generation fleet, the Nordic system is capable of withstanding large demand- and generation-driven fluctuations and sudden disturbances in both transmission and generating units (Eurelectric, 2011).

[11] The original figure is in German.

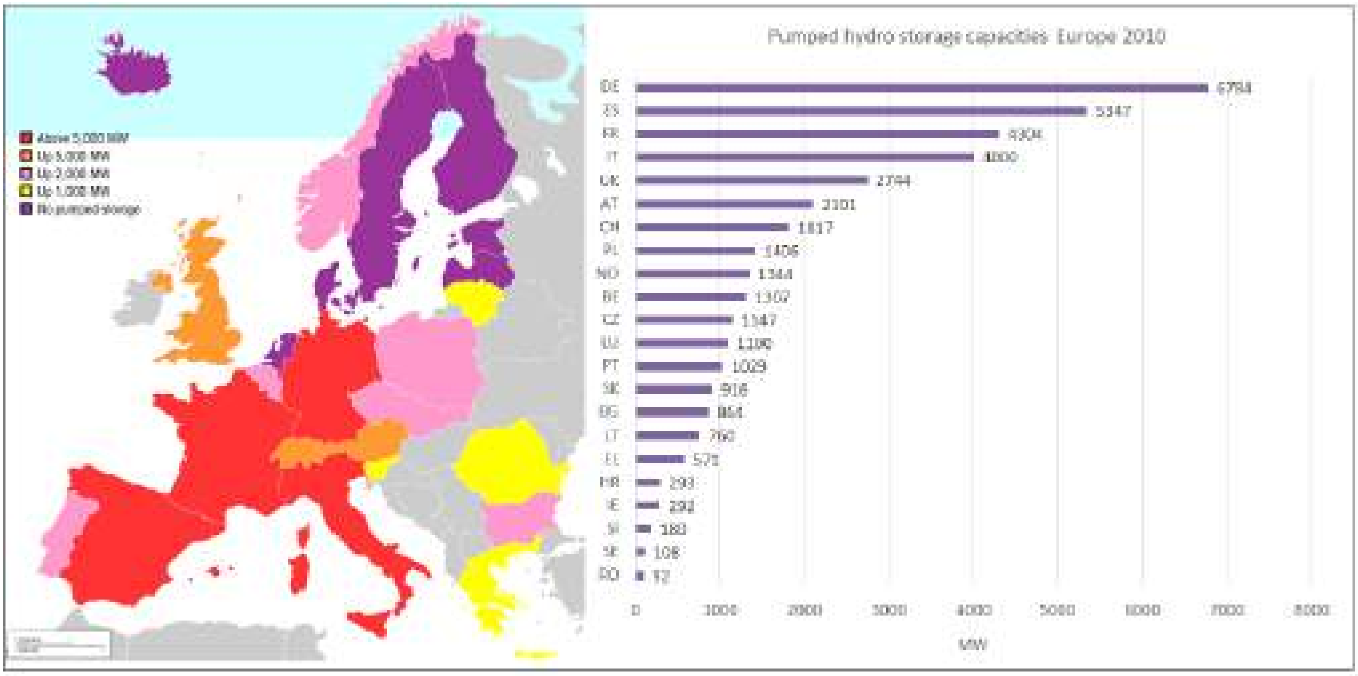

Figure II-X: Pumped hydro storage capacity in Europe in 2011 (left figure) and 2010 (right figure) (Zuber, 2011), own representation based on data from (Eurostat, 2010) .

In particular, Sweden and Norway contribute to the large reservoir storage capacities in Scandinavia. Since the main generation source is hydro, security of supply is influenced by the inflow into rivers from precipitation or from melting snow.

In order to back-up the seasonal imbalances between inflow, which can vary substantially between years and the load, considerable storage capacities are available in both countries (Sweden: 34 TWh, Norway: 85 TWh), designed to have a large flexibility up to a long timescale. Supported by a few pumped hydro storage facilities, balancing needs are currently fulfilled by the existing hydro plants enabling both downward and upward regulating capacity. Short term deviations are balanced via energy trade taking advantage of the interconnections in Scandinavia and to other countries.

An example of short-term flexibility is presented in Figure II-XI. Wind generation in Denmark (green line) dropped from almost rated power (1800 MW) to zero within a timeframe of six hours due to a storm front that hit the country at the beginning of 2005. The drop in wind generation was balanced by hydropower from Norway (orange line) changing the trade balance from export to import (purple line) when wind farms got disconnected gradually due to excessive wind speeds. In summary, the Scandinavian region has two strong assets to cope with the increased requirements for flexibility due to variable RES: hydro storage and a physically and operationally well-interconnected market (Eurelectric, 2011).

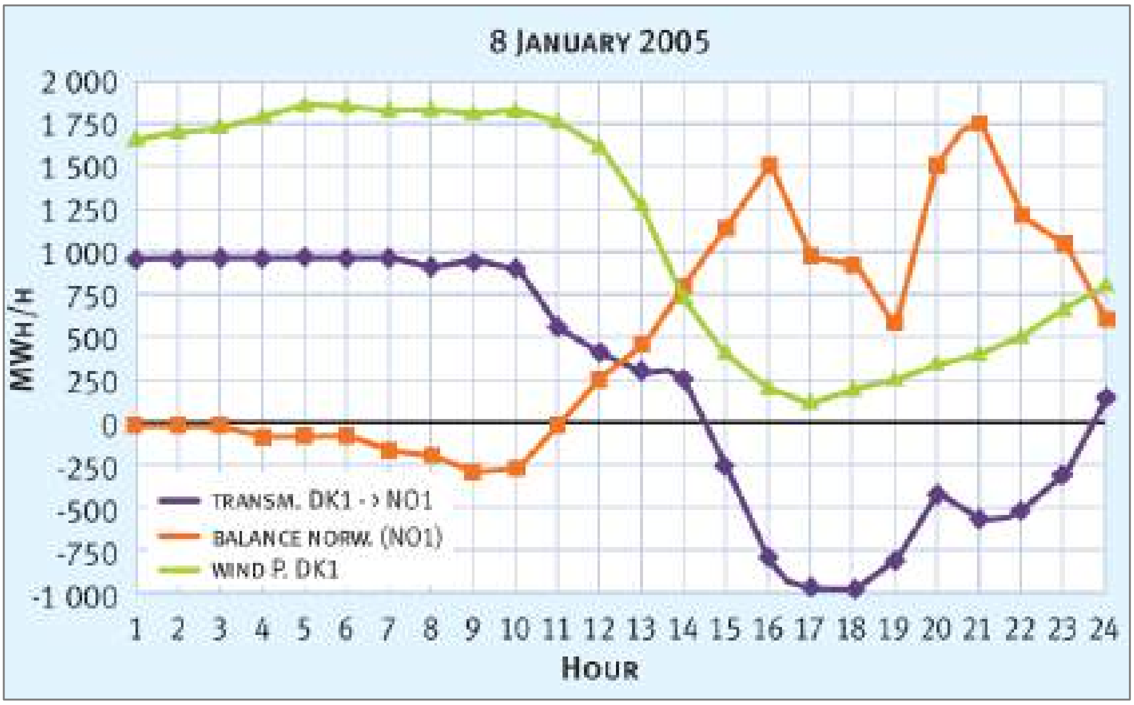

Figure II-XI: Danish wind production between a storm and the balance of flows between Denmark and Sweden (Eurelectric, 2011).

II.B.2.iii Cyprus

Having no indigenous hydrocarbon energy resources, Cyprus operates an isolated power system and relies fully on imported fuels for electricity generation. Up to 2010, the electricity generation portfolio included three conventional power plants with a total capacity of 1438 MW firing mainly heavy fuel oil (92% of the energy mix) and gasoil (Poullikkas, Papadouris, Kourtis, & Hadjipaschalis, 2014).

Power supply from renewable energy sources was not significant (PV: 6 MW, Biomass: 7 MW (Poullikkas, Papadouris, Kourtis, & Hadjipaschalis, 2014)) before the installation of the first wind farm in 2010 with a capacity of 82 MW. Meanwhile, the installed capacity increased up to 147 MW in 2014[12].

In contrast to large interconnected power systems, frequency control in isolated systems is a significant concern in the daily operation. Large frequency deviations due to sudden changes in variable generation and/or transmission outages must be balanced immediately to preserve security of supply. With the influence of intermittent feed-in from renewable energy sources, the requirements in this regard have increased (Petoussis & Stavrinos, 2010).

As Cyprus has currently neither energy storage nor demand side resources, the flexibility must be provided by conventional generation and RES curtailment (Nikolaidis & Charalambous, 2013). However, a case study for Cyprus' power system revealed that the available reserve is not capable of balancing the real-time fluctuation of wind. Higher shares of intermittent energy would further constrain the ramping capability of the conventional power plants due to part loading of generators

[12] Source: http://www.thewindpower.net

(Catalao, 2015). Consequently, the system will not be able to integrate wind power without high levels of real-time wind curtailment or demand shedding (Vos, Petoussis, Driesen, & Belmans, 2013).

However, although Cyprus currently operates no energy storage, there are licensed pumped storage capacities and capacities of pumped storage projects in an early planning stage (no license yet). In the context of projects with no license yet, a total installed capacity of 190 MW is planned to be able to operate 11 hours at full load (Eurelectric, 2011).

II.B.3. Drivers for New PHS Development

Drivers for new PHS development are region- or country-specific but generally renewable energy targets and increasing the efficiency of current hydro plant are often seen as drivers for new development. Targets for increasing renewable energy are stimulating wind energy and solar power developments in many countries. Increased variable generation is seen to drive the demand for system reserve and increase the value of PHS in ancillary services. Reducing the volatility or increasing the efficiency of current hydroelectric assets is also a prime driver for developers who already have existing hydroelectric or PHS assets.

PHS plants are characterised by long asset life (typically 50 to 100 years), high capital cost, low operation and maintenance cost, and round-trip efficiencies of 60-85%. There are however limited siting possibilities for new PHS. The large-scale deployment of PHS projects carries with it some environmental impacts that should not be overlooked. PHS in particular – even for new facilities and designs – has a significant land and water footprint, and not negligible GHG (CH_4) emissions released at the reservoir surface (dam).

Project costs for PHS are very site-specific with some quoted costs varying from €600-€3000/kW (Deane, Ó Gallachóir, & McKeogh, 2010). Furthermore, capital costs depend not only on the installed power but also on the energy storage at any given site.

Figure II-XII details the published capital costs and installed capacities for a number of proposed PHS plants, the majority of which are in Europe. A general linear trend is observed in the relationship between installed capacity and capital cost. Capital costs per MW for select proposed PHS are between €470/kW and €2170/kW.

PHS projects may be remunerated in liberalised electricity markets through ancillary services payments, capacity payment, and electricity trading. Generally, electricity trading is the major source of revenue for PHS as operators may take advantage of energy arbitrage opportunities. For arbitrage, pumping price has to be at least 25-30% lower than selling price to compensate for energy losses, and significant volatility (not necessarily high energy prices) must be present in the wholesale price of electricity to make revenue. Increased wind generation in many countries can naturally lend itself to increased price volatility in the wholesale market.

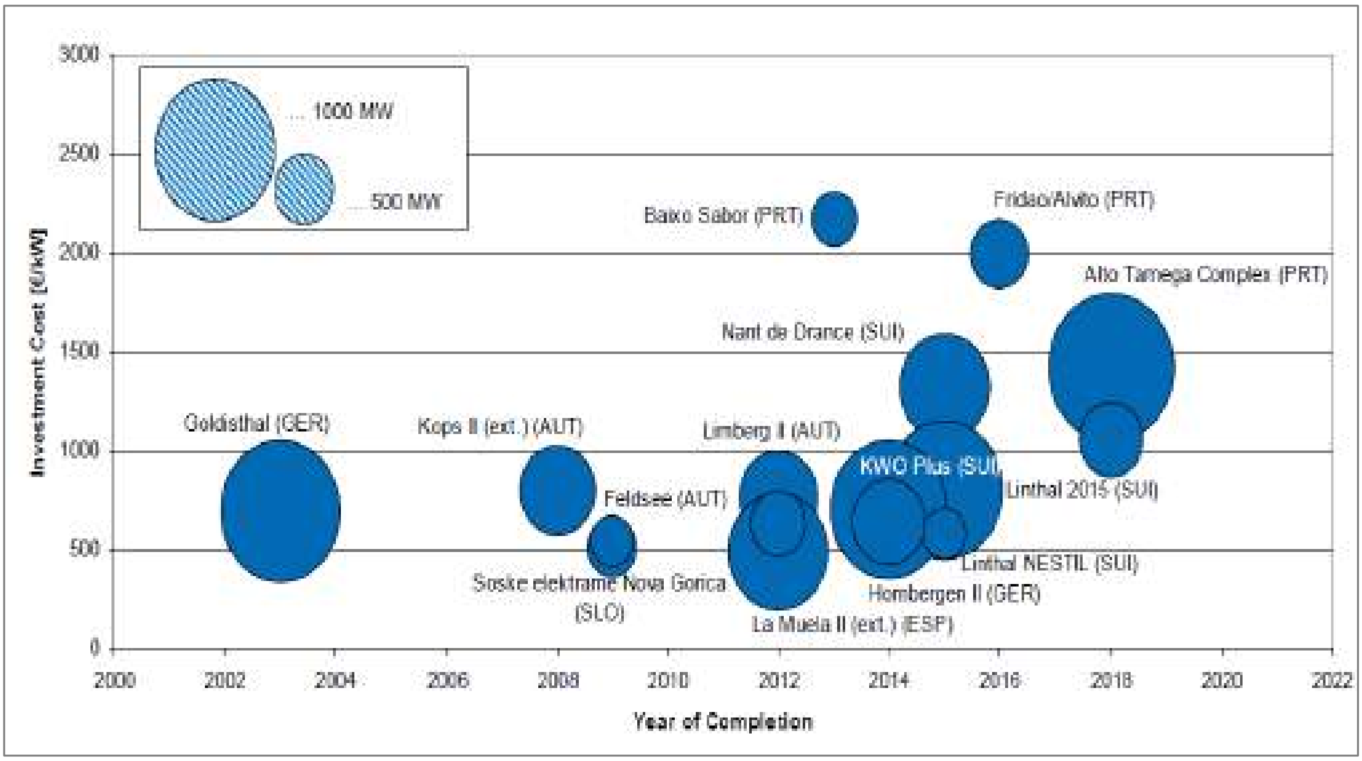

Figure II-XII: Comparison of the specific investment cost for selected PHS systems[13]

Current trends for new PHS plants show that developers operating in liberalized markets are tending to repower, enhance projects, or build 'pump-back' capacity in existing hydraulic plants rather than traditional 'pure pumped storage'. This is partly driven by a lack of economically attractive of new sites. An advantage with 'pump-back' facilities is that energy storage is generally much greater, thus allowing plants to store large amounts of cheap electricity. Plants with significant inflow may also operate as conventional hydroelectric generation units during times of excess inflow thus increasing the economic competitiveness of the plant.

Repowering or enhancement of existing projects is also attractive as large savings are made on the capital expenditure of the project by using existing infrastructure, usually reservoirs thus also reducing environmental and planning issues. Repowered plants benefit from improvements in technology and design and usually use more efficient and larger turbines/pumps. From an investor standpoint the internal rate of return for repower projects is on average higher than that of new plants.

II.B.4. Value of PHS

The value of pumped storage in a system is highly dependent on the makeup of the system in terms of thermal generation portfolio, renewables penetration and type, market structure and interconnection. A number of existing studies have aimed to quantify the value of pumped storage in diverse systems and these studies are well summarized in an EU JRC scientific and policy report which

[13] Source: http://www.store-project.eu/

assesses the storage value in electricity markets (Andreas Zucker, 2013). The section below is based on information and text from this report.

Table II-III: Pumped hydro energy storage market studies in JRC report

Market Region	Year	Arbitrage	Reserve	Author and Year
BE	2007	Yes	yes	(X. He, 2011)
DE	2002-10	Yes		(Steffen, 2011)
DE, FR	2010-30	Yes	yes	(Loisel, Mercier, Gatzen, Elm, & Hvroje, 2010)
ES, IT	2008-11	Yes		(Rangoni, 2012)

Figure II-XIII shows a review of profitability figures from the JRC report for EU projects where the graph bars represent the ranges of annual gross margins found. Gross margin is the difference between storage profits and variable plus fixed O&M costs per kW of installed (turbine) capacity[14].

The report highlights that as authors make different assumptions on the investment level and weighted average costs of capital (WACC), the profitability estimates are usually not comparable. Therefore, annuities for an investment in a generic PHS are shown as straight **black lines** in Figure II-XIII. Profitability is reached if gross revenue exceeds these lines. A total of four possible cases are shown by combining two different values for the WACC (6% and 10%) with two different levels of specific CAPEX (500 – 1500 €/kW) taken from the Technology Map of the European Strategic Energy Technology Plan. The different WACC levels represent typical values for a regulated and a deregulated business. An investment lifetime of 35 years is assumed for both cases. The possible storage gross margin of a PHS seen in all scenario/studies varies by about one order of magnitude (10 – 110 €/kW/year). Arbitrage only operation allows the repayment of a low CAPEX (500 €/kW) investment in some cases but does not provide sufficient revenues for a high CAPEX (1500 €/kW) investment in any of the cases considered. Repayment of a high CAPEX / low WACC combination seems feasible if reserve markets (and other services) are included. In none of the studies do gross revenues allow repayment in a high WACC and high CAPEX scenario (**red lines**).

[14] If a specific study did not explicitly state annual storage revenues, these are calculated from other data published. For (Loisel, Mercier, Gatzen, Elm, & Hvroje, 2010), annual gross margins were recalculated from the net present value, applying interest rate, economic lifetime and inflation rates provided. In the case of (X. He, 2011) the figures obtained from the simulation of one week of storage dispatch optimisation were extrapolated in the report to an entire year simply multiplying results for 52 weeks. All currency units are normalised to €2012 applying exchange rates and inflation figures according to Eurostat. Arbitrage only figures are presented for all studies except from (Steffen, 2011) and (X. He, 2011) which also include revenues from reserve and other markets.

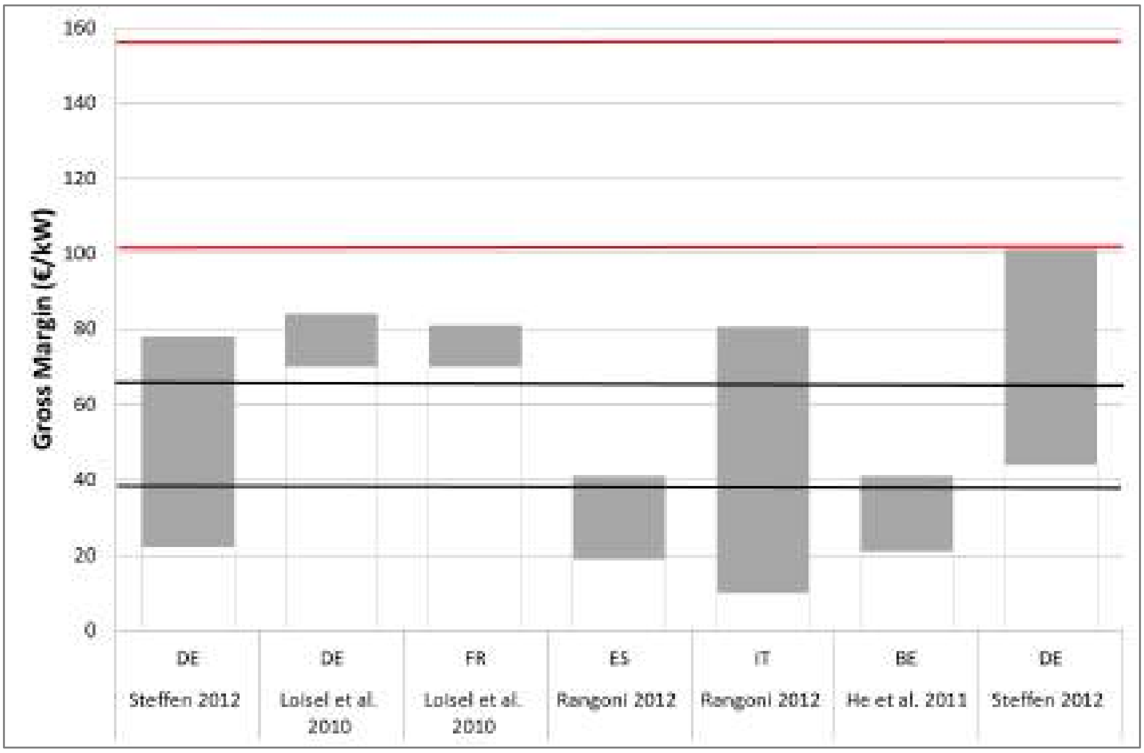

Figure II-XIII: Gross Margin (€/kW) for Pumped storage for a number of study regions. Information on chart is taken from JRC Report[15]

(Rangoni, 2012), calculates storage profitability for Italy on the basis of the average national power price (PUN, *prezzo unico nazionale*), which results from the zonal prices weighted with exchanged volumes for each Italian price zone. Spreads may be higher within zones providing a further upside potential. Finally, publications on hybrid systems of PHS and wind on non-interconnected Islands were not included in the JRC review.

II.B.5. Barriers to PHS Deployment

At a European level the *STORE-Project.eu*[16] has made a number of recommendations to assist the deployment of PHS and storage projects. The project recommends that if a need for energy storage is identified, then this should be clearly expressed in energy policy, and that discernible objectives are developed at EU and Member State level. It recommends that physically viable sites be identified and tested (subject to environmental assessment) at a strategic level during the development of PHS plans and programmes. It recommends that clear MS guidelines for sustainable project development, best practice guidelines, and guidelines for planning are established to further the sustainable development of bulk energy storage. Finally, it recommends that the efficiency and speed with which bulk EST

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[15] The ranges shown in Figure II-XIII are given by the following variation of the input parameters. Historical energy prices taken from different years: (Steffen, 2011) (Rangoni, 2012). Prices are generated by a market model making different assumptions on the storage penetration, (Loisel, Mercier, Gatzen, Elm, & Hvroje, 2010)

[16] Source: http://www.store-project.eu/

projects are considered during the planning approval stage be improved with the establishment of appropriate mechanisms.

II.C. Future role of energy storage

To assess the role of electricity storage in the medium and long term, a set of long-term, low-carbon electricity supply options were analysed for Europe. A multi-region cost-optimization TIMES electricity model was used to generate insights on future electricity supply options under given policy constraints. The model, called European Swiss TIMES[17] Electricity Model[18] (EUSTEM), has 11 regions encompassing 20 of the EU-28 countries (plus Switzerland and Norway, see Figure II-XIV). The EUSTEM model covers 96% of the total electricity generation and 90% of the total installed capacity of the EU-28 + Switzerland and Norway in 2014[19] (see Table A2). It should be noted that EUSTEM is an electricity system model, i.e. there is no representation of heating or transport sectors. As such, the focus of this analysis is to generate insights on the need for electricity storage.

Figure II-XIV: EUSTEM regions

EUSTEM identifies the "least-cost" combination of technologies and fuel mixes based on their operation characteristics, to satisfy exogenously given electricity demands under a given set of constraints. The framework allows for prospective analysis over a long model horizon (70+ years) while at the same

[17] The Integrated MARKAL/EFOM System (TIMES) framework is a perfect foresight, technology rich, cost optimization modelling framework (Loulou, 2005)
[18] It is worth noting that EUSTEM is an extension to the existing five regions Cross border Swiss TIMES electricity model (CROSSTEM), see (Pattupara et al., 2015)
[19] ENTSO-E (European network of transmission system operators for electricity) - Consumption data (2014). Retrieved 31 March, 2013, from https://www.entsoe.eu/data/data-portal/consumption/Pages/default.aspx

time being able to represent a high level of intra-annual detail in demand and supply (e.g. electricity load curves). It also has an enhanced storage algorithm, enabling the modelling of electricity storage systems (Loulou, 2005). It should be noted that demand responses and electricity efficiency improvements are not explicitly represented, with demand side measures expected to be captured in the assumed electricity demand growth rate.

EUSTEM is used to generate insights on possible electricity supply pathways to decarbonize the EU electricity sector by 2050, similar to the EU Roadmap to 2050[20] . The model identifies the long-term capacity expansions plans to meet the given policy targets. To understand the real time dispatchability of the electricity system, the installed capacity from EUSTEM is eventually analysed in an *EU-28 electricity market model* (see Section V.C). It also describes revenue generated by storage processes to study the economic viability of pumped hydro and battery storage systems in current market conditions.

II.C.1. Key Assumptions and model characteristics

Several modelling assumptions and input data are used in EUSTEM. In the following subsection, an overview of the modelling framework and key assumptions are described. A more detailed model description can be found in (Pattupara, 2015).

EUSTEM has a time horizon of 70 years (2010-2080), divided into eight unequal time periods as shown in eriod of 2046-2055.

Table II-IV: Time period definition in EUSTEM. Each period has a milestone year, which is the result-reporting representative year, and displays the average value of parameters over the period, e.g. 2050 represents the period of 2046-2055.

Table II-IV: Time period definition in EUSTEM

Period Number	Period Duration	Time Period	Milestones years
1	1	2010-2010	2010
2	2	2011-2012	2011
3	5	2013-2017	2015
4	8	2018-2025	2021
5	10	2026-2035	2030
6	10	2036-2045	2040
7	10	2046-2055	2050
8	25	2056-2080	2068

[20] European Commission, "Energy Roadmap 2050", 2011. Retrieved 22 February, 2013, from http://ec.europa.eu/energy/energy2020/roadmap/doc/com_2011_8852_en.pdf

Each period also has an hourly representation within a year, differentiated by four seasons and three types of days as shown in Figure II-XV.

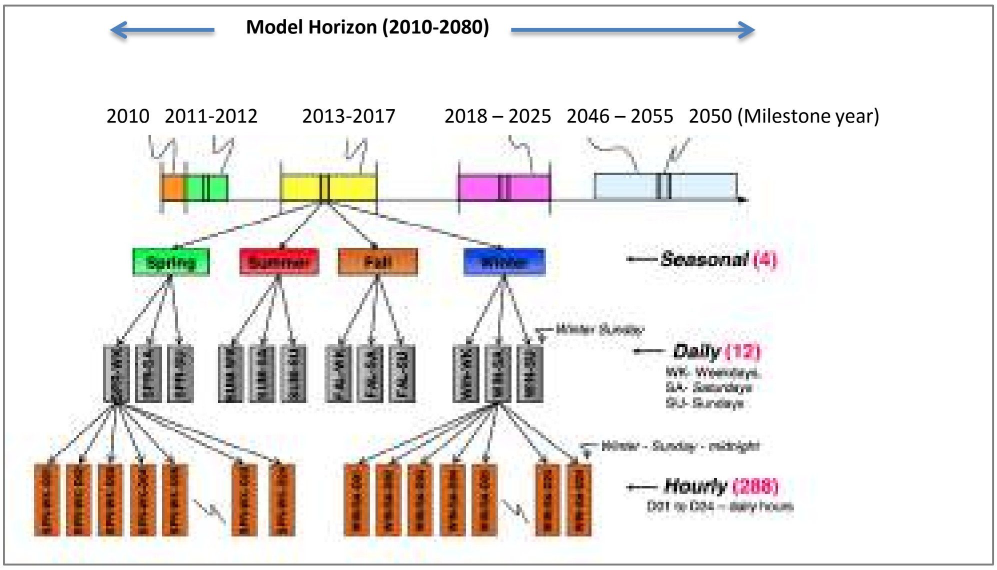

Figure II-XV: Intra-annual details in EUSTEM

The model is calibrated to actual data from IEA on electricity demand, generation mix, electricity trade and capital stock in 2010. Operational characteristics of power plants, seasonal resource availabilities, trade patterns and other such characteristics are included in the model. Existing generation technologies are calibrated to seasonal and annual electricity generation, as hourly level calibration was not possible due to lack of data. However, the availability of renewable energy resources is implemented at seasonal (hydro) and hourly levels (solar, wind). In addition to the existing fleet of technologies, the model has the option to invest in new electricity generation technologies. There are more than 20 categories of electricity generation technologies, which use primary energy resources in the form of renewables (solar, wind, hydro, etc.), fossil and nuclear as inputs (see

Appendix A – EUSTEM model).

The model also has the option to trade electricity between the regions based on long-run marginal costs of electricity generation. Highly simplified interconnectors are represented to quantify the needs for interconnector capacity between the regions. The existing inter connector capacity based on historical trade patterns are included and the model has the option to expand the interconnectors. EUSTEM does not have an electricity transmission or distribution grid. The transmission constraints are captured in the analysis using the dispatch model described in Section V.C on Future Business models.

Electricity demand

For the current analysis, electricity demands are adopted from the Reference scenario of the EU trends to 2050 study[21] . Figure II-XVI shows the electricity demands for the EUSTEM regions.

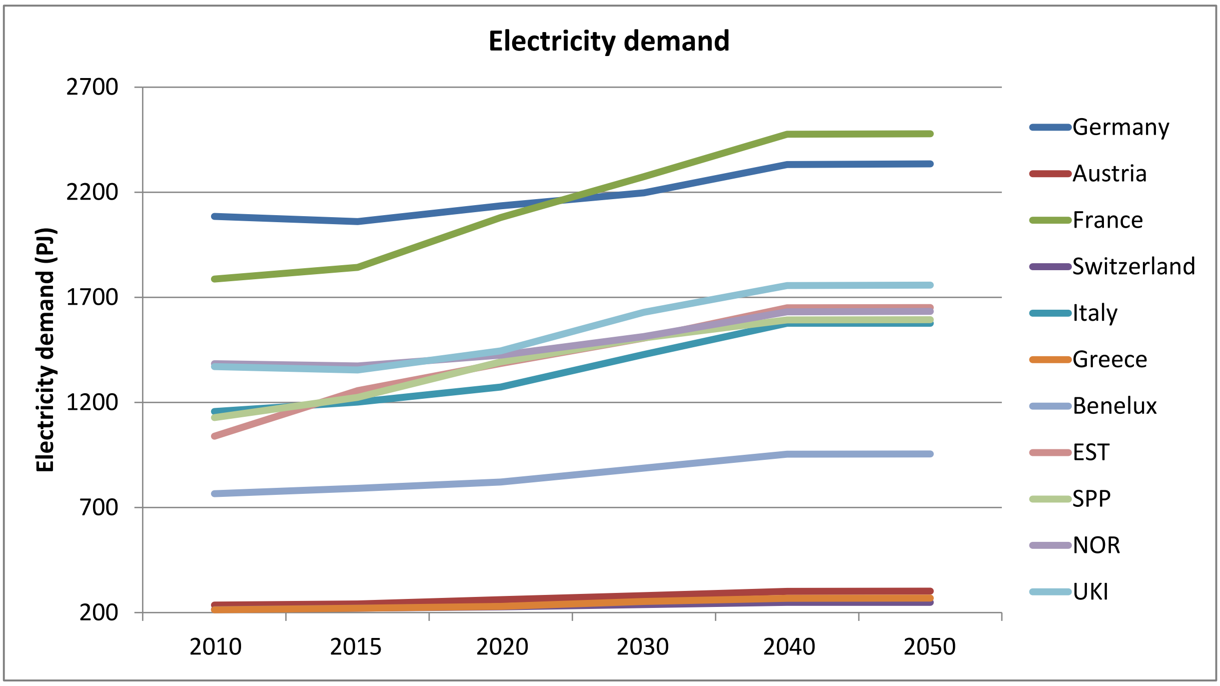

Figure II-XVI: Electricity demand projections of EUSTEM regions

[21] European Commission. (2013). EU Energy, Transport and GHG Emissions, Trends to 2050 - Reference Scenario. Luxembourg.

For intra-annual variations in electricity demand, electricity load curves from the year 2010[22] are implemented for each region for the entire model horizon. Thus, this load curve assumption does not take into account for example the increasing electrification in the transport sector and/or space heating applications (e.g. electric vehicles, heat pumps), which could significantly alter future load curves. Demand response programmes (such as shifting of the load by controlling the function of electric loads in the demand sectors) are not considered.

Electricity generation Technologies

Key techno-economic details of electricity generation technologies used in EUSTEM are given in Appendix A – EUSTEM model. Detailed information on technology descriptions is available in (Pattupara, 2015).

Energy Resource Costs

Fuel prices for natural gas, oil and coal are taken from the World Energy Outlook 2014[23] (International Energy Agency, 2014). Cost of uranium fuel rods are taken from[24]. Appendix A – EUSTEM model shows the energy price assumptions. The energy prices from 2050 are extrapolated to the remainder of the model time horizon.

Renewable potentials

Renewable energy resource potentials for the current analysis are adopted from the JRC-EU-TIMES model (Simoes, 2013). A summary of the renewable potential is given in Table II-V.

Table II-V: Renewable energy potentials (2050)

	CH	AT	FR	DE	IT	EAST	NORDIC	BNL	UKIRE	SPAPO	GRC
Solar PV	32.5	75	670	733	700	600	223	255	618	715	131
Solar CSP	-	-	-	-	36	-	-	-	-	38	15
Wind Offshore	-	-	4.4	461	1.5	11	250	48.6	83.6	122	38.5
Wind onshore	14.4	50	380	475	174	150	300	460	198	370	74.8

[22] ENTSO-E (European network of transmission system operators for electricity) - Consumption data (2014). Retrieved 31 March, 2013, from https://www.entsoe.eu/data/data-portal/consumption/Pages/default.aspx
[23] International Energy Agency. (2014). *World Energy Outlook 2014*. Paris, France: IEA.
[24] Energie-Spiegel No.20. (2010). Sustainable Electricity: Wishful thinking or near term reality?, 2012, from http://www.psi.ch/info/MediaBoard/Energiespiegel_Nr20_072010_d.pdf

Biomass	122	8	119	101.1	33	50	124	60.8	44	33	5
Waste	8.1	3.08	16	21.2	18	12	22	20	12	20	1.5
Geothermal	16	2	1.71	20	26	15	0.1	5	0.6	35	1
Hydro Dam	74.5	31.1	131	3.6	50	8	628	0.3	8	146	29
Hydro Run of River	47.2	116.9	135	86.4	80	50	406	2.4	12	86	4
Tide	-	-	55	-	11	23	100	4.3	375	93	14.4

CCS potentials

Carbon Capture and Storage (CCS) technologies are assumed to be available from 2030 onwards. The market potential of CCS technologies are limited by the CO_2 storage potentials; and the storage potential are taken from various EU studies (Geocapacity, 2009) (Simoes, 2013). For the scenario analysis in this report, the CO_2 storage potentials are limited to hydrocarbon fields – for a conservative estimate (see

Appendix A – EUSTEM model).

II.C.2. Scenarios

Two scenarios have been analysed in this case study. The first scenario represents a least-cost electricity supply option, which is used as a baseline for comparison. The focus of the discussion will be on a decarbonisation scenario of the EU electricity system, which will highlight the importance of electricity storage in a high renewable based electricity generation system.

Least Cost scenario (*LC*)

This scenario is the cost-optimal electricity supply scenario, which gives the least cost electricity supply without reflecting foreseeable market changes resulting from climate change mitigation policies or renewable targets. In this scenario, no specific constraints on technologies are included, except the existing national policies on nuclear phase out. Technology growth constraints have been applied on certain technologies such as coal, wind and solar PV based on historical trends to reflect technical limits to deploy them and thereby prevent unrealistic penetration of these technologies. A CO_2 price is implemented based on the EU ETS prices from the "new energy policy" scenario of the IEA World Energy Outlook[25]. The CO_2 price varies between 11 $€_{2010}$/t- CO_2 in 2010 and 44 $€_{2010}$/t- CO_2 in 2050 and is very close to assumption in the Reference scenario of the EU Energy Roadmap[20]. There are no market incentive tools (such as feed-in-tariffs) applied for the case study. No particular market or interconnector constraints are applied on electricity imports / exports between regions, i.e. the model has full freedom to trade electricity and expand the cross-border interconnector capacity.

Decarbonisation scenario (*CO2*)

The decarbonisation scenario has the same boundary conditions as the *LC* scenario, with an additional CO_2 emission cap to decarbonise the EU electricity sector by 2050. The total CO_2 emissions from the power sector across the regions are reduced by 61% of the 1990 levels by 2030, and 95% by 2050. These emission caps are in line with the CO_2 emission targets in the EU energy roadmap to 2050[20].

II.C.3. Results

In this section, results are presented for Germany, France and Italy. For the business model case study (described in Section V.C), these three countries have been selected for a detailed analysis to evaluate the importance of storage systems. France and Italy have substantial flexible hydro systems which can be used to balance and store electricity. Germany on the other hand has limited pumped hydro storage potential, thereby enabling a contrasting outlook compared to France and Italy.

The model generates a wide range of outputs such as installed capacity, generation mix, hourly long-run marginal cost, capital cost, etc. For the case study, we limit the discussion of results to installed capacity, which is an input to the dispatch model (see Section V.C) and cost of capacity expansions.

Capacity Expansion

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[25] International Energy Agency. (2010). *World Energy Outlook 2010*. Paris, France.

Figure II-XVII shows the total installed capacity of Germany in a CO_2 emission reduction scenario for the period 2030-2050, as well as the base year of 2010. Results from the least-cost scenario (LC) are also shown to illustrate the technology preferences of the model in the absence of any climate change mitigation targets. Although such a least-cost scenario is highly unlikely, it is presented as a basis to understand the cost-optimization framework.

Results from the LC scenario show that in the absence of nuclear-based generation in Germany, coal power plants become the most cost-effective technologies. In the absence of any long-term renewable incentive schemes (like the feed-in-tariff), coal technology (especially lignite technology available in Germany) would still be more cost optimal than renewable technologies such as wind and solar PV, which is seen by the phase-out of existing wind and solar PV technologies by 2050. Although wind and solar PV technologies become much cheaper towards 2050, several other factors could lead to such a generation mix.

In this instance for example, Germany invests considerably in cheap lignite technology and exports excess base-load electricity to neighbouring countries that lack the availability of such baseload options (for example, in the year 2050, around 50TWh of electricity is exported by Germany to neighbouring regions, mainly Switzerland and BENELUX). Such a situation may seem unrealistic, but from a purely cost-optimal point of view, in a single market model, there would be no reason for Germany to invest in renewables to meet its electricity demand if it can export excess baseload electricity and generate more revenue, thereby decreasing its overall system cost. However, the total share of renewables for all of EUSTEM increases from 13% of the total demand in 2010 to 27% in 2050. This could either be due to other constraints preventing the investments in fossil-fuel technologies (see Figure II-XVIII for situation in France) or due to better performances of renewables depending on geographical locations (see solar PV investments in Figure II-XIX for situation in Italy). The large base-load generation from coal plants is supplemented by dispatchable gas and hydro plants to provide sufficient flexibility for the system.

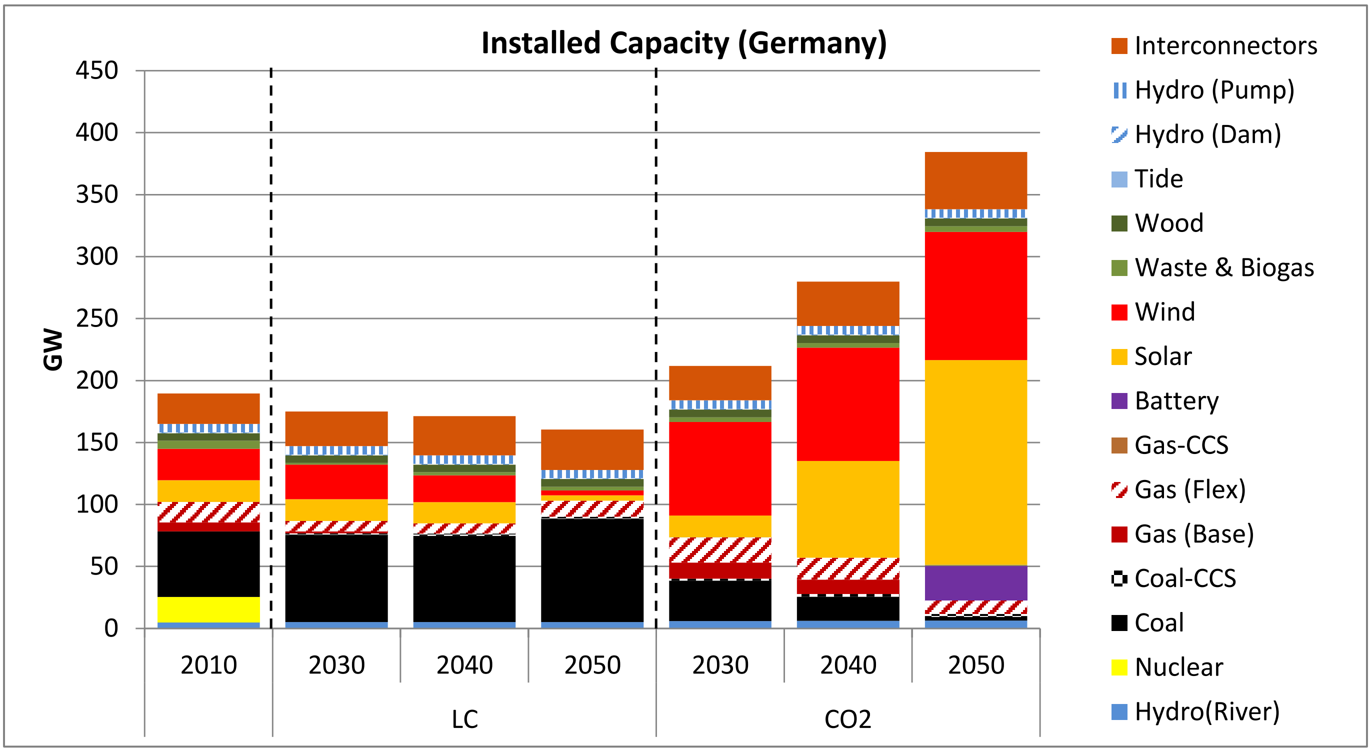

Figure II-XVII: Electricity capacity expansion (Germany)

In the climate target scenario (*CO2*), coal based generation is gradually replaced by wind and solar PV, supplemented by flexible gas and electricity imports. The share of renewable capacity increases from 35% in 2010 to 76% by 2050. In order to balance the intermittent generation from renewables, an investment in around 27 GW of battery storage is required by 2050, in addition to the existing 7 GW of pumped hydro storage available in Germany. This installed storage capacity amounts to around 9% of the total installed capacity. Additional flexibility is provided by dispatchable gas plants, which accounts for approximately 3% of the total installed capacity. Finally, there is a large expansion in interconnector capacities, which increases by around 84% between 2010 and 2050. The majority of the expansion occurs at the cross-border capacities with the NORDIC and BENELUX regions, due to their high renewable and CCS potentials. Results indicate that in order to meet stringent CO_2 emission targets, it would be cost optimal for Germany to become a net importer of electricity (around 20% of the final electricity demand is imported).

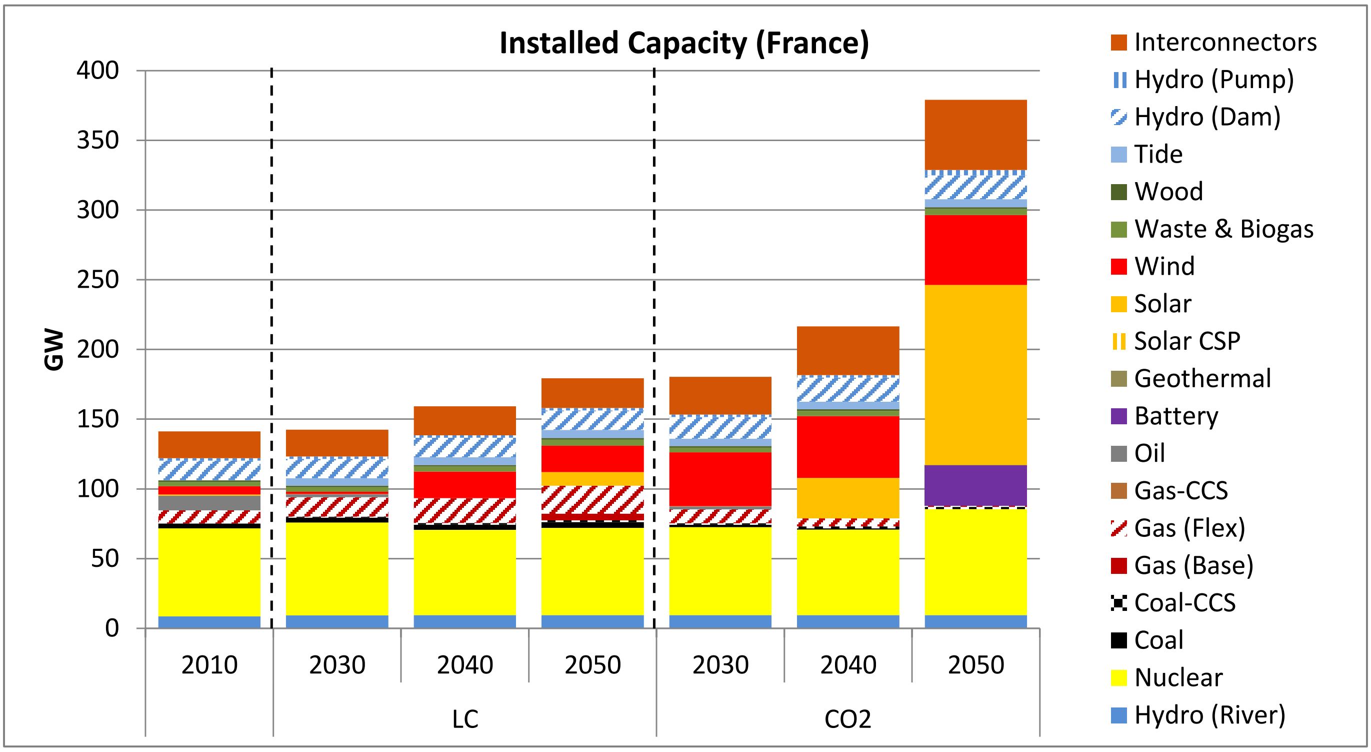

Figure II-XVIII: Electricity capacity expansion (France)

Figure II-XVIII shows the installed capacity in France. It is assumed that France keeps its nuclear generation at the today's level (in energy terms). In the *LC* scenario, one can observe a steady increase in wind and solar PV technologies especially by 2040 and 2050. This is attributed to the growth constraints applied on nuclear and coal expansion. Hence in order to meet the increasing electricity demand, renewable generation is competitive compared to gas-based generation, although some investment in flexible gas plants is still made to add flexibility in the electricity system. This is an apt example of an external constraint influencing decisions in a cost optimization model (in contrast to the German case discussed previously).

In the *CO2* scenario, France has a slightly higher nuclear capacity by 2050. This higher capacity is used at lowered annual load factors to account for seasonal variabilities of its high renewable share. Solar PV and wind capacities expand considerably by 2050 and account for around 48% of total installed capacity. The stringent CO_2 emission cap makes investments in gas and coal plants unattractive in this scenario, thereby resulting in higher penetrations of renewable technologies. Battery and pumped hydro storage also accounts for almost 9% of total installed capacity (as was the case with Germany), despite the availability of dam hydro (5% of total installed capacity) which provides flexible generation. Interconnectors are also significantly expanded (from 20 GW to almost 50 GW), primarily to facilitate electricity exports to Italy, Switzerland, Germany and UKI due to its low-carbon nuclear option.

Figure II-XIX shows the installed capacity of Italy. In the *LC* scenario, solar PV and wind technologies already occupy a share of 46% of the total installed capacity by 2050. In this case, base-load electricity is obtained from coal-based generation and electricity imports from EAST and France. The model then prefers solar PV technologies, whose profile follows the electricity peak load at noon (see load curve diagram in Appendix A), with flexible gas and hydro technologies filling the gaps. This is in strong contrast with France, where renewable investments were made due to the inability to expand its baseload option; and Germany, where renewable technologies were phased-out by 2050 in favour of coal-based baseload generation.

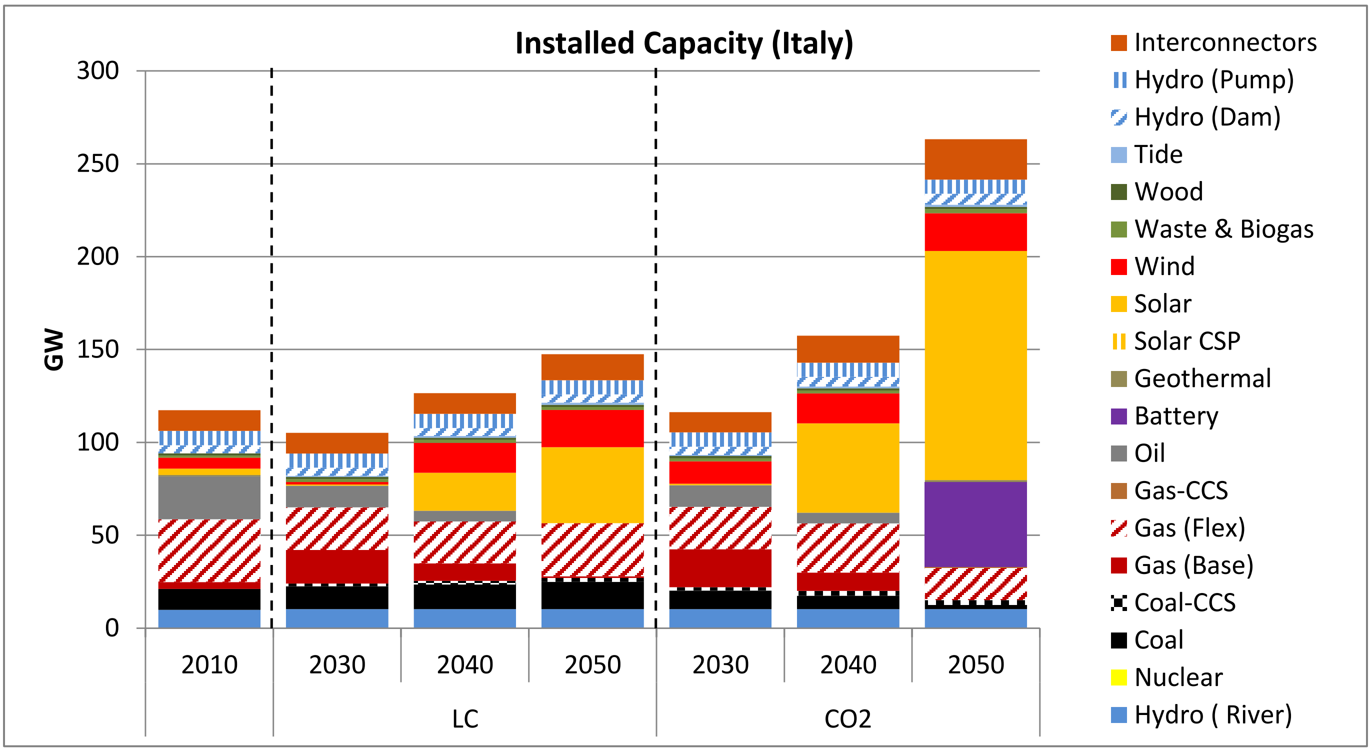

Figure II-XIX: Electricity capacity expansion (Italy)

For Italy, results for the decarbonisation scenario (*CO_2*) closely resembles its least-cost solution (*LC*) till the year 2040. Afterwards, there is a significant increase in solar PV installations, making up almost 47% of the total installed capacity (which rises to 55% when including wind). Battery and pump storage accounts for more than 20% of the total capacity, significantly higher than in France and Germany. This is explained by the much higher share of solar power in the generation mix of Italy, compared to Germany where wind-power dominates over solar PV generation. Interconnectors with neighbouring regions are almost doubled, with Italy still remaining a net importer of electricity (around 14% of the demand in 2050 is covered by electricity imports, primarily from France).

Based on the results discussed above, the penetration of new storage technologies such as batteries occurs only towards the end of the time horizon, i.e. by the year 2050. This is attributed to two main reasons, namely the share of intermittent renewables and the cost reduction of storage technologies. For example, in Italy, the share of solar PV and wind technologies is around 27% of the total electricity generation in the year 2040, which increases to 59% by 2050. Concurrently, the share of flexible generation technologies such as gas plants, which help in balancing the system, is reduced from 36% in 2040, to 18% in 2050, mainly due to the stringent CO_2 emission cap. Hence the increase in share of intermittent generation and decrease in flexible backup technologies, coupled together with the reduction in technology costs makes investments in battery technology cost effective by the year 2050. This conclusion is valid for the other regions as well, where similar trends are observed.

Cost of capacity expansion

One of the key outputs of EUSTEM is the total system cost. For this particular case study, focus has been limited to the capital investment costs to examine the economic feasibility of storage systems.

Figure II-XX shows the capital investment required in Germany. The cumulative investment required in the *LC* scenario between 2018 and 2050 is around 232 billion Euros[26]. On the other hand, investment costs in the *CO_2* scenario for the period 2046–2055 alone is close to 350 billion Euros. The cost of decarbonizing the electricity system of Germany incurs an additional capital cost of almost 450 billion euros between 2018 and 2050. The cost of investing in battery storage, which primarily occurs during 2046–2055, is approximately 40 billion euros, i.e. four billion euros per year in that period. The revenue generated by battery electricity storage must be able to cover this investment costs. Whether this is the case with current market mechanisms is analysed in Section V.C.

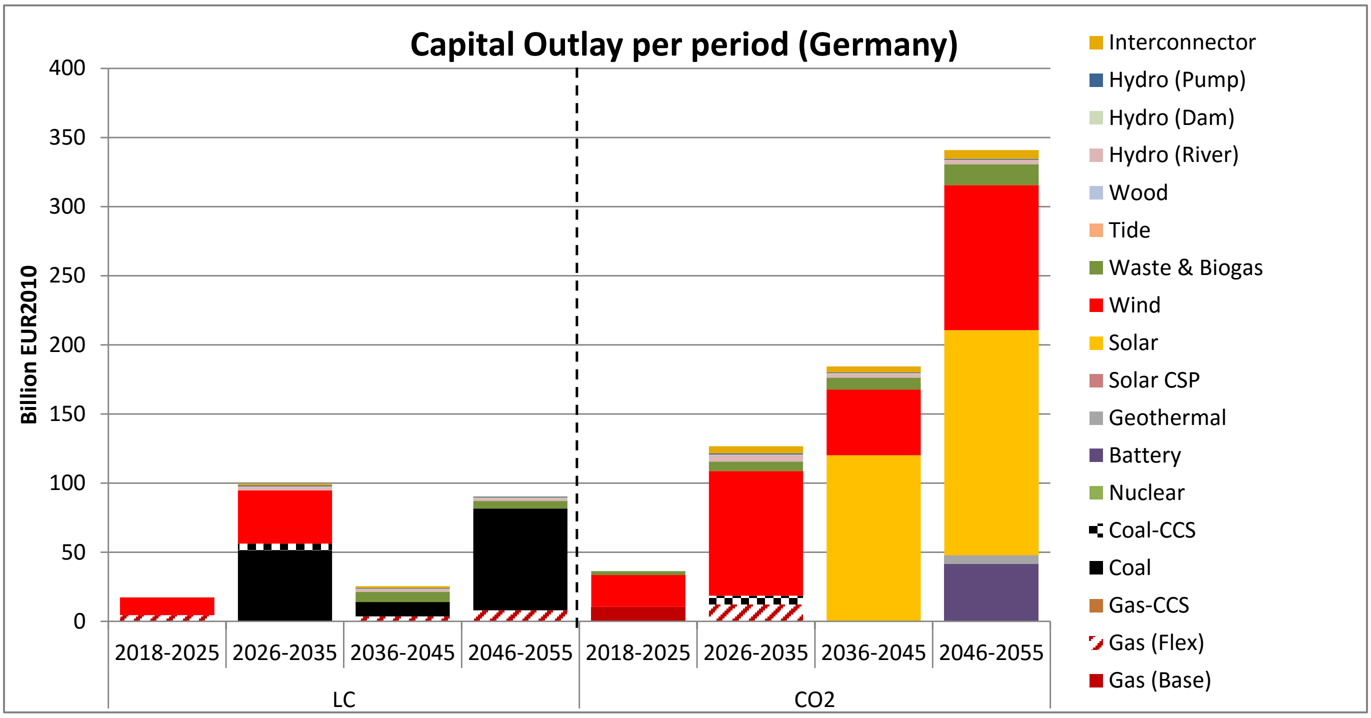

Figure II-XX: Investment costs per period (Germany)

Investment costs for France and Italy are shown in Figure II-XXI and Figure II-XXII respectively, with the key information summarized in Table II-VI. As mentioned before, Section V.C assesses the business case for storage systems such as battery and/or pumped hydro based on the analysis presented in this section.

Table II-VI: Capital cost comparison

Key cost parameters (Billion EUR2010)	France	Italy

[26] Currency Conversion: 1 €2010 = 1.32 CHF2010 (XE (2014), Current and Historical Rate Tables, http://www.xe.com/currencytables/)

Total Cumulative Cost 2018 – 2050 (*LC*)	383	211
Total Cumulative Cost 2018 – 2050 (*CO_2*)	798	447
Cost of decarbonizing electricity sector	415	236
Cost of battery storage (for period 2046 – 2055) (*CO_2*)	43	68

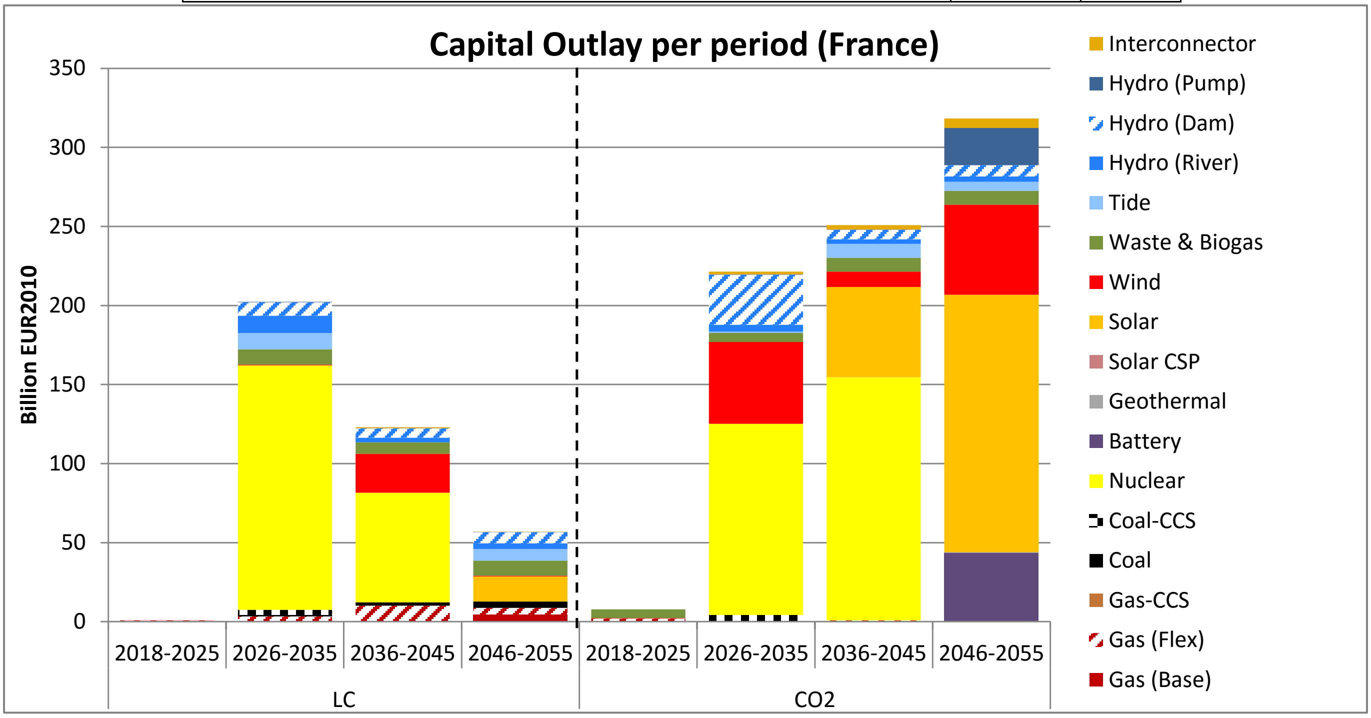

Figure II-XXI: Investment costs per period (France)

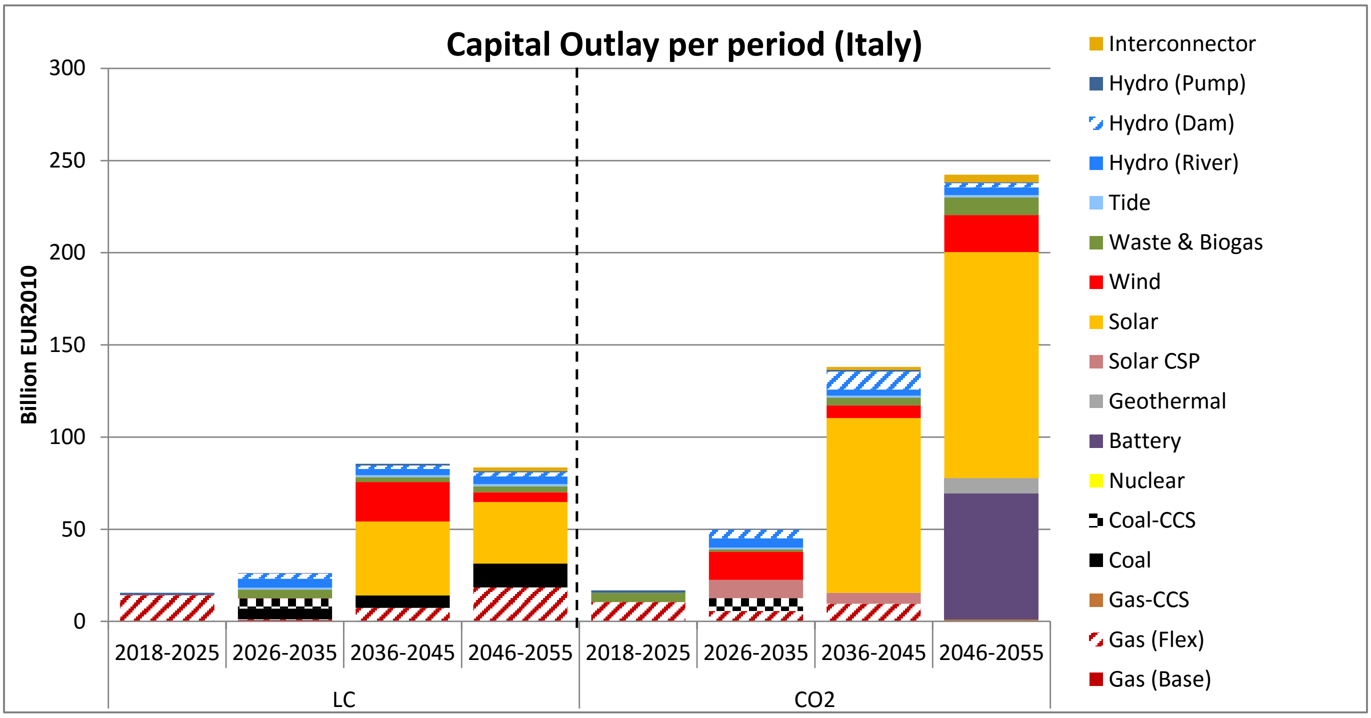

Figure II-XXII: Investment costs per period (Italy)

II.C.4. Other storage technologies

Most of the new options related to demand or storage are rather small-scale technologies. Their deployment requires a suitable IT infrastructure and raises the question of data management (smart grid). In the long run, conventional power plants can be seen as facilities that provide flexibility by storing electricity in form of fuels. Other options are currently not applicable for economic reasons. Flexibility related to network specific measures depends on the characteristics of the specific system and is therefore strongly case specific (Papaefthymiou, Grave, & Dragoon, 2010). With the ongoing market penetration of electric vehicles (EV) as a form of distributed electrical storage units, an additional source of dispatchable demand and demand response is given by controlling the charging process. For example, the charging could be timed to periods of high variable generation. Further benefits could be gained by controlling the charging rates, and thereby providing contingency reserves or frequency regulation reserves. Similarly, EVs could (partially) discharge to the electrical grid (Vehicle-to-grid, V2G) at times when flexible energy service is needed (NREL, 2010).

II.D. Case study of Cyprus: storage in a small isolated power system

The electricity supply system of Cyprus is rather small as compared to that of most EU member states. Currently, it relies primarily on oil-fired generation (93% in 2014)[27], majority of which is heavy fuel oil, along with diesel to a lesser extent. In a system of about 1650 MW, the biggest unit is 130 MW and is fired by heavy fuel oil. Due to the discovery of offshore natural gas reserves, it is expected that

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[27] TSO Cyprus, "RES Penetration," 2015. [Online]. Available: http://www.dsm.org.cy/nqcontent.cfm?a_id=3656&tt=graphic&lang=l2. [Accessed: 17-Nov-2015].

gas-fired generation will dominate the electricity mix in the future. At the same time, the island has a significant solar potential, as in the six summer months there is an average of 11.5 hours bright sunshine daily[28]. As such, even though there was a push towards wind energy in the beginning of the decade, in the last few years solar photovoltaic installations are increasing steadily; the declining investment cost of the technology facilitated to this.

As the cost of generation from certain renewable energy technologies gains competitiveness to that of thermal generation, in an effort to become less dependent to imported fuels and to conform with EU legislation in regards to renewable energy and greenhouse gas emissions, there is a general agreement on the island that the share of renewable energy should increase. Due to the fact that the power system of Cyprus is completely isolated from grid networks of neighbouring countries, the extent to which this will occur will be determined by the system's flexibility. The Transmission System Operator of Cyprus is already expressing concerns that the integration of high shares of variable renewable energy technologies in a system without storage, and in the absence of grid interconnections, will increase the system's vulnerability to a potential blackout substantially, as the existing thermal units may not be able to cope with rapid variations in generation from variable renewables.

The present analysis addresses this concern and aims to identify the cost-optimal levels of renewable energy generation without compromising system reliability. Storage options are allowed so as to introduce an aspect of flexibility in the system and improve the case of variable renewable energy technologies, which inherently lack the ability to provide dispatchable load.

II.D.1. Model and Scenarios

An existing electricity supply model developed in MESSAGE and used in a previous IRENA study[29] is taken and translated into an OSeMOSYS model (M. Howells, 2011). Code extensions that allow the incorporation of short-terms constraints into long-term energy system models are included (M. Welsch, 2014). Therefore, aspects not present in the Cyprus MESSAGE model such as ramp up and ramp down rates of thermal plants and minimum stable generation are included in this effort. The following scenarios are assessed and compared:

- No Storage Scenario (NS Scenario): All generation options are allowed to compete for a share in the generation mix based on their techno-economic characteristics. The renewable energy target in electricity supply for Cyprus is set as a constraint for minimum renewable energy contribution. Renewable energy technology deployment is only limited by the ability of thermal units to ramp up and down with an increased frequency. Natural gas does not exist as a fuel option.
- Enhanced Storage Scenario (ES Scenario): In this scenario, a pumped-hydro storage of 130 MW is considered for installation in 2021. Additionally, flow batteries are allowed in the system, centrally connected to the transmission network, while Li-ion batteries can be installed along with distributed rooftop photovoltaic systems. The storage options connected to the

[28] Department of Meteorology, "Climate of Cyprus." [Online]. Available: http://www.moa.gov.cy/moa/ms/ms.nsf/DMLcyclimate_en/DMLcyclimate_en?OpenDocument. [Accessed: 28-Aug-2015].
[29] IRENA, "Renewable Energy Roadmap for the Republic of Cyprus," Abu Dhabi, 2015.

transmission network (i.e. pumped-hydro and flow batteries) are allowed to contribute to the required operational reserve, while distributed storage options are also allowed to provide ancillary services. Natural gas is not considered as a fuel option in this scenario either.

- Domestic Gas Scenario (DG Scenario): Building on the Enhanced Storage Scenario, this case investigates the financial competitiveness of storage options in case domestic natural gas reserves become available for electricity generation by 2023.

All scenarios use fossil fuel price assumptions as provided by the World Bank[30] and the International Energy Agency[31].

II.D.2. Results

As shown in Figure II-XXIII, the introduction of storage in the system has a significant effect on the penetration of renewable energy technologies in the generation mix. Whereas in the NS scenario by 2030 capacities of photovoltaics and wind reach 1,296 and 1,177 MW respectively, in the ES scenario the respective values are 2,912 and 877 MW. Similarly, share of renewable energy generation in 2030 increases from 64% in the NS scenario to 100% in the CS scenario.

[30] The World Bank, "World Bank Commodities Price Forecast." 20-Oct-2015.
[31] IEA, *World Energy Outlook 2015*. Paris: Organisation for Economic Co-operation and Development, 2015

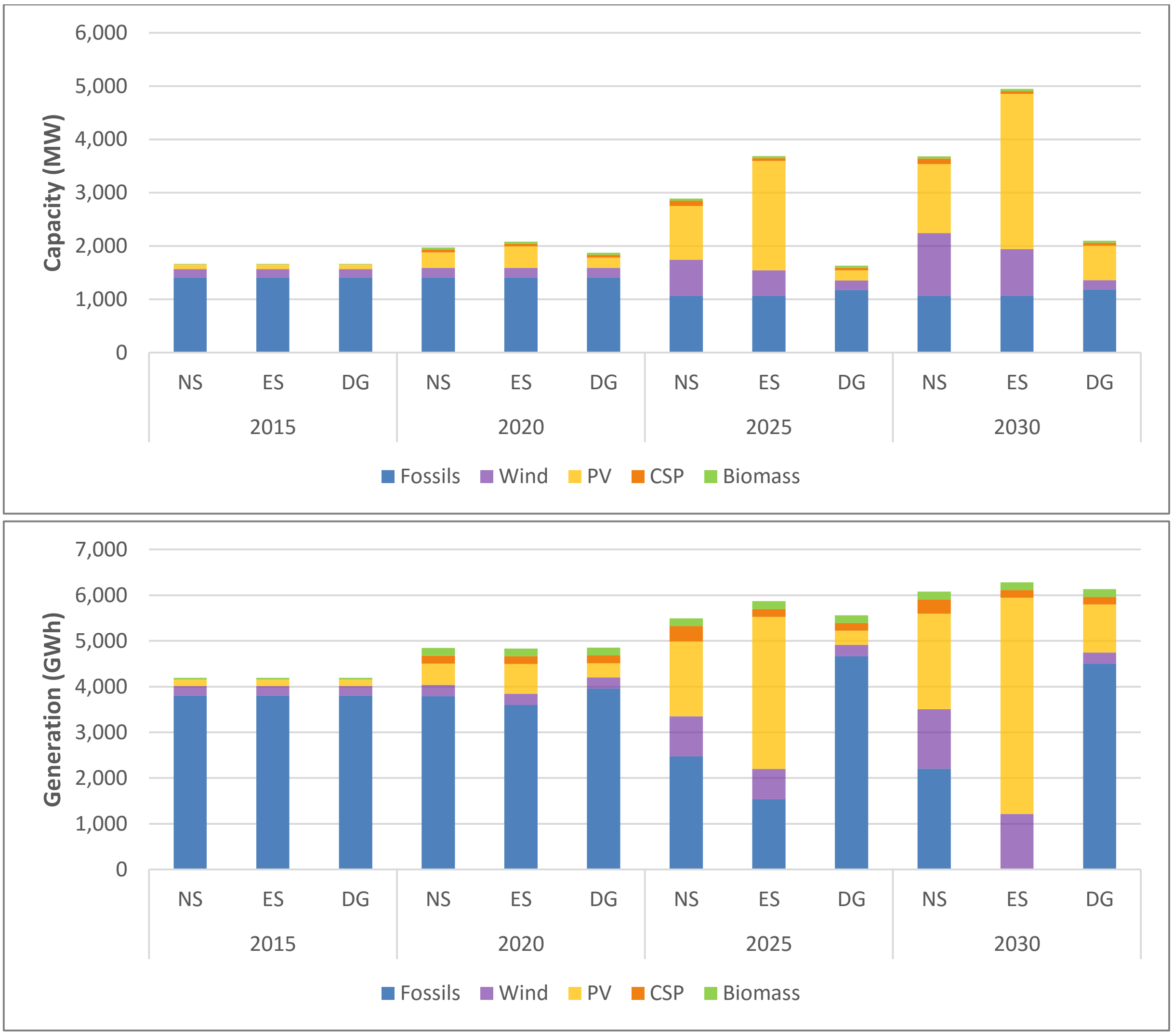

Figure II-XXIII: Evolution of capacity and generation mix in the three scenarios. The obvious difference in generation between scenarios in 2025 and 2030 is due to higher losses as a result of increased use of storage.

Despite the fact that deployment of storage is capital-intensive, it is deemed economically optimal to develop this decentralized storage, as it allows for additional cost-competitive generation from variable renewable energy options. This is achieved only through time of use arbitrage, where cheap electricity from PV can be used to charge the storage during the day and then be used during peak demand periods in the evening, but not through provision ancillary services, even though this option is allowed. It is worth mentioning that pumped-hydro is not deemed as cost-competitive, but if it were forced to be installed, it would be used extensively for the provision of secondary reserve. Operational reserve demand is considered, which corresponds to constant 60 MW, plus 50% of instantaneous wind generation, plus 10% of instantaneous PV generation[29].

It is interesting to see that the potential arrival of natural gas (DG Scenario) can have a big impact on cost-competiveness of distributed PV and storage, as well as renewable generation as a whole. In the DG scenario, share of renewable energy generation is limited to 27%. At the same time, whereas 606 MW of Li-ion batteries are deployed in the ES scenario, these are at just 16 MW in the DG scenario by 2030.

In regards to economic impact, in the ES scenario the introduction of storage coupled with subsequent capacity additions of renewable energy technologies lead to higher investment costs, but lower fuel and CO_2 costs, as compared to the NS scenario. Nonetheless, the cost savings achieved through substitution of oil with natural gas is much greater as can be seen in Figure II-XXIV. The average cost of electricity by 2030 is 30 EUR/MWh lower in the ES compared to the NS scenario, while in the DG scenario this is further reduced by about 20 EUR/MWh.

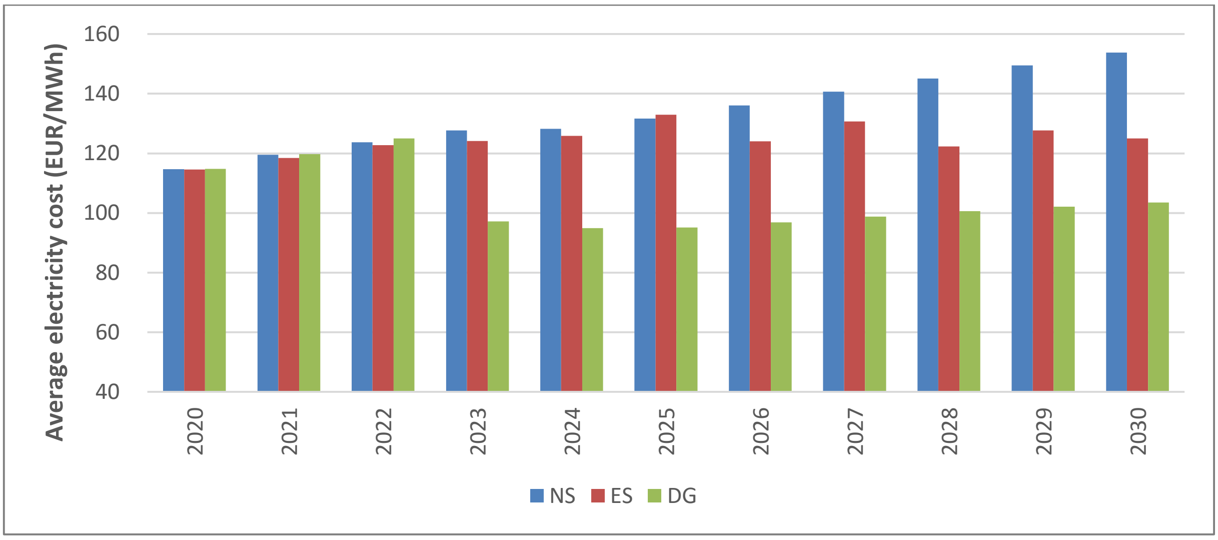

Figure II-XXIV: Average cost of electricity in the three scenarios.

II.D.3. Discussion and Conclusions

As clearly shown in the results, the introduction of storage has the potential to dramatically increase the share of variable renewables in the electricity supply system of Cyprus. Even in a completely isolated system, renewables in combination with storage options have the potential to improve the energy independence of Cyprus, as it will no longer rely on any imports for its electricity generation sector, while this would be entirely clean energy. It can be argued that if this is feasible in Cyprus, it should be even less technically challenging to achieve in interconnected EU member states, since concerns regarding system reliability will be lower. It should be noted that even though certain short-term technical constraints are considered in this analysis, a separate grid stability analysis is required to ensure the technical feasibility of the results.

It should be highlighted that cost-competitiveness of storage options, especially that of distributed PV generation coupled with Li-ion batteries, will be affected by the availability of gas. As seen in the results above, once gas becomes available, the deployment of distributed PV with storage is suppressed dramatically. Nonetheless, we do not take into account potential earnings from gas exports in a scenario with 100% renewable energy generation with storage. Additionally, in this case, even though the average electricity cost is more expensive, by about 20-25%, fossil-fuel independence is achieved. In larger EU member states with limited domestic fossil fuel reserves, this would also mean greater energy independence and hence an improvement in energy security.

The Cypriot case is unique in that it lacks interconnections with other grid networks. As such, demand for reserve has to be provided internally, while flexibility regarding intermittent renewable energy generation is reduced, leading to a higher potential for curtailment. Such a case would be applicable for remote locations or other islands, but for the vast majority of EU member states, such concerns are not relevant. Therefore, in regions with similar climatic conditions and with existing grid interconnections (e.g. Greece, South Italy, South Spain), cost-competitiveness of distributed generation options, with or without storage, would be higher.

Clearly, distributed storage is more competitive in the case of higher distributed generation and promotion of self-consumption. For instance, the majority of photovoltaics introduced in our scenarios corresponds to decentralized plants, even though they are more expensive to deploy than utility-scale photovoltaics. In the latter case, foreign investors would most likely be involved, which could mean that profits are not necessarily recirculated in the local economy, which is not the case with distributed generation. Socioeconomic aspects such as job creation from installation and maintenance of distributed generation and storage options are not represented in our model and these could make their case even stronger.

III. BUSINESS MODELS

III.A. Business models & value chain decomposition

An illustration of the value chain decomposition is shown in Figure III-I. The critical point relates to the differentiation between transmission and distribution (T&D) operators and third parties with regards to system ownership and operation. This point is further detailed in the next sections.

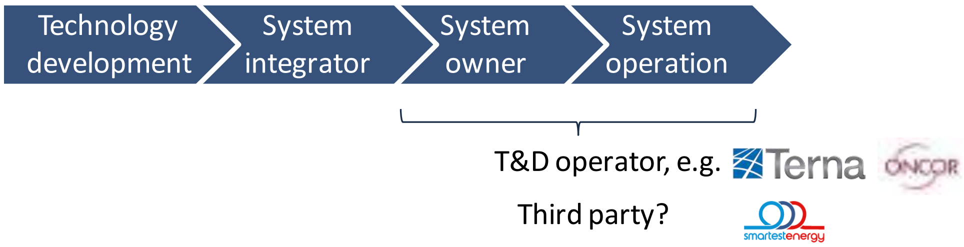

Figure III-I: Illustration of value chain decomposition

III.A.1. Ownership models

Ownerships models for T&D storage are closely linked to the regulation locally enforced. In order to assess the actual potential of ownership models, a global legal review has to be performed. One should also keep in mind that the legal framework for storage assets is not clearly established and is rapidly evolving due to the appearance of needs such as grid support.

In Europe, transmission network operators can have three different statuses:

- **Independent System Operator** (ISO): a fully unbundled system operator without the grid assets that are still belonging to an integrated company. This system is used in Ireland and in Latvia but is not recommended by the European Union as assets owner do not have proper incentives to develop the grid, to maintain it and to treat congestions. This regulatory system is a hindrance for the development of storage assets as it does not entice new investments but it on the other hand it abolishes a major regulatory difficulty present in unbundled systems where TSO own grid assets.
- **Ownership Unbundling** (OU): the most popular model in the EU, it states that the TSO must be unbundled from any integrated company. The TSO owns the grid assets and is paid by energy suppliers to use the grid. Under current European regulation, they must not own any producing assets, including storage assets.
- **Independent Transmission Operators** (ITO): quite similar to a TSO respecting the OU principle. The main difference is that the TSO is an independent subsidiary of an integrated company. This independence is guaranteed by specific mechanisms enforced by the regulator. Eight countries in the EU have ITOs.

The unbundling principle, present in Europe and in many countries (Australia, etc.), hinders the acquisition of storage assets by system operators. Recent acquisition by Terna of storage assets for grid support purposes, mitigates this prohibition and attests that no clear legal statement exists for storage ownership and operation by TSO respecting the unbundled principle. One way to remedy this precarious regulatory situation is to contract third parties to install, own and run storage assets and to access, as an energy producer, revenue streams on unregulated markets.

The Table III-I summarizes the current business incentives and regulatory status of different potential owners in different market structures. Today, the most favourable situation appears for integrated companies, existing in markets without any unbundling principle, where the storage asset owner and operator is vertically integrated and can access any services he desires.

Other cases describe the current situation in the EU:

- In the case of an ISO operator, the asset owner is allowed to construct and own an asset but with the lease system, he does not have a strong incentive to invest in the network. He is even less enticed to invest in storage as he will not be the primary beneficiary of additional revenues due to this investment (the ISO will benefit from it).
- In case of an OU or an ITO, the business incentives are present as these two types of operators would benefit from investments in storage assets thanks to both regulated and unregulated services. However, current regulation is not permitting such investments.

Eventually, the last option is a law-abiding way to benefit from all services. However, it requires the involvement of an independent third-party, thus complicating the business model and revenue streams for the system-operators.

Table III-I: Summary of current situations of ownership

Owner	**Business Incentives**	**Regulatory** Status
Integrated companies (Non-EU countries)	🟢	🟢
Integrated Companies without System Operation (when the system operator is an ISO)	🟡	🟢
System Operators (OU & ITO)	🟢	🔴
Third- Party	🟡	🟢

III.A.2. Business models

Depending on the above ownership models, 3 main business models can be outlined.

System operator owns the storage asset and captures network value only: In this model, the investment is made by the transmission or distribution network operator to provide network services only. The energy storage asset is integrated in its regulated assets base (RAB), and so is eligible for cost recovery through regulated revenues. Preferably, the transmission or distribution network operator keeps the whole control of the system, doing itself the dispatch in case of congestion or reliability events. The operation of the system by a third party is also an option (e.g. stakeholders with specific skills for optimizing and managing energy storage devices).

This business model presents two main features:

- On one hand, it is expected that it is easier to implement and less subject to regulatory constraints as has been shown by Terna in Italy (see above), since only regulated revenues are captured (investment deferral, network reliability). This indeed does not threaten the unbundling principle.
- On the other hand, the revenue base is limited to regulated revenues only, which could hamper its economic viability.

System operator owns the storage asset and captures both network and market values: In this model, the investment is made by the transmission or distribution network operator to provide network services first. The transmission or distribution network operator is also seeking for unregulated revenues from market services (arbitrage, frequency regulation). The storage system should then be considered as a "shared asset" by the regulator in unbundled markets. The distributor has then a partial control of the system, at least for the dispatch in case of congestion or reliability events. In unbundled markets, one or several third parties are likely to take the market dispatch responsibilities.

This business model presents two main features:

- On one hand, it is expected that it is more complex to implement and subject to regulatory constraints, since both regulated and unregulated revenues are captured. This requires third parties to be involved in order to capture unregulated services. There are uncertainties about the legal feasibility of this model, but it is being investigated by some T&D operators, such as ONCOR in Texas (see above) who proposed to "auction off" to independent third parties the wholesale market dispatch.
- On the other hand, the revenue base is larger than for the above model, which could strengthen its economic viability.

A third party owns the asset and captures network and market value: In this model, the storage asset is owned by an independent party, who can be registered as a generator and/or a customer on the market. The transmission or distribution network operator has a contractual agreement with the energy storage system owner to benefit from network services. Expenses of the transmission or distribution network operator then qualify as OPEX and can be recovered through the fee charged for using the network. The third party keeps the control of the storage system and can optimize the use of the system according to its own interest (market operations, etc.) as well as the requirements of the distributor.

This business model presents two main features:

- On one hand, it is expected that it is more complex to implement due to different contractual agreements and revenue streams. The legal feasibility of this model is moreover not acquired.
- On the other hand, the revenue base is larger than for the first model, which could strengthen its economic viability.

In addition to these models, mixed models may also emerge. For instance, in the UK, UK Power Networks (UKPN) plans to gain indirect access to the market through a supplier with specific expertise in renewables trading (Smartest Energy) (UK Power Networks, 2014). This supplier has been chosen as a project partner to collaboratively develop the new arrangements needed to provide access to the wholesale market to facilitate access to the products and services necessary under this category. With this approach, there is therefore no need for UK Power Networks to hold a Supply Licence for such purposes for the duration of the project. With Smartest Energy providing the route to market for imported or exported electricity from the device, the storage facility will be interacting directly and visibly with the wholesale market and its contribution can be explicitly measured to deliver learning outcomes. It is also unaffected by the prohibition of not allowing a DSO from holding a generation license.

If the local storage via aggregators is allowed to participate in the balancing market, the business case could be significantly improved. This could be implemented with a system similar to what has been applied by PJM in the US, where they opened for aggregators called Curtailment Service Providers (CSP). According to PJM, a CSP is

> "*the entity responsible for demand response activity for electricity consumers in the PJM wholesale markets*. *A CSP may be a company that solely focuses on a customer's demand response capabilities, a lower electricity utility, an energy service company or other type of company that offers these services. The CSP identifies demand response opportunities for customers and implements the necessary equipment, operational processes and/or systems to enable demand response both at the customer's facility and directly into the appropriate wholesale market. This requires the CSP to have appropriate operational infrastructure and a full understanding of all the wholesale market rules and operational procedures*" (PJM)."

III.B. Potential of Storage in Transmission and Distribution (T&D)

III.B.1. Potential, market drivers

Two different types of market drivers can be identified specifically for storage applications in T&D:

- Network-related drivers influencing the need for grid support services
- Drivers influencing storage competitive advantage compared to alternative solutions

The main identified driver for T&D storage is the changing location of generation capacities in Europe. The increased renewable energy capacity supported by political commitment leads to a reconfiguration of European networks, to overcome the geographical mismatch between the location of renewable generation and consumption centres. This is already a driver for some countries, e.g. Italy.

III.B.2. Bottlenecks

However, legal access to storage assets construction and operation by system operators in unbundled markets is difficult. Though it may be possible in some instances (e.g. in Italy), the valuation of the full range of storage services is not possible for the moment in European unbundled markets, thus hampering the potential economic viability of storage.

III.B.3. Interaction political, economic, technical, legal and socio-environmental

Other economic and technical factors also influence the economic viability of grid storage:

- The increasing CAPEX intensity of network upgrades may in some instances show opportunities for storage. However, these opportunities are case and location-specific and depend on a number of factors, including a high peak to average demand ratio, modest additional load and/or expected demand growth served.
- Storage services additional to investment deferral are likely to be critical in reaching the economic viability of storage, even though they should not be a driver for T&D storage.
- The development of demand management may compete in the future with distributed storage used for demand-side management in smart grids.

Table III-II: Classification of the main drivers and barriers for stationary storage for the transmissions & distribution grid segment

	Drivers	Status in 2015	Anticipated evolution
Political	▪ Political commitments to develop renewable energies ▪ Supply and Storage sides –oriented VS demand side-oriented	🟢	🟢
Economical & Technological	▪ Importance of the valuation of network reliability services and market services ▪ Development of nodal & zonal pricing ▪ Increasing CAPEX intensity of networks upgrade ▪ Development of demand management ▪ Development of new generation technologies with different spatial distribution (cf political aspect)	🟡	🟡
Social & environmental	▪ Increased environmental and social opposition to new infrastructures construction	🟡	🟡
Legal	▪ Easier legal access to storage assets construction and operation by System Operators in unbundled markets	🟢🔴	🟡
Caption - Status definition			
Driver with positive impact	🟢	Driver with important negative impact	🔴
Driver with neutral or slightly negative impact	🟡	Driver with important disparities and opposite effects	🟢🔴

III.B.4. Description of drivers and barriers

III.B.4.i Political aspects

Changing location of generation capacities, the increasing role of interconnections. The major shift of the generation fleet initiated in Europe features more intermittent generation located in circumscribed areas favourable to the deployment of these assets. Since these locations may be far away from the consumption centres or from current generation assets, transmission networks have to accommodate for this. In addition to this, the emergence of electricity prosumers that both consume and produce electricity implies a challenge for distribution networks.

The shift of the generation mix, with a reduction of conventional power generation capacity and renewable energy development, is the first driver for grid development (ENTSOE, 2014).

The nature of the renewable energy resource varies from Member State to Member State within Europe. In general, the Southern states may have a greater reliance on photovoltaic generation with a lesser reliance on wind. Northern states on the other hand may have a greater reliance on wind. The more mountainous states will have a propensity towards hydropower, and coastal states may have an input from wave and tidal. Overall, each Member State is likely to exploit the renewable energy resources that exist within their own boundaries (EASE & EERA, 2013). Given the fact that most intermittent production is concentrated in specific, circumscribed areas, as well as the fact that renewable generation cannot produce on demand, the occurrence of backbone congestions may become a more frequent event (EASE & EERA, 2013).

One way to solve local or regional imbalances is by increased exchange of power by interconnecting transmission lines. In Germany for instance, the geographic mismatch of power supply and demand has contributed to significant balancing issues from the northern suppliers and southern demand centres (IEA, 2014). This problem is exacerbated by local grid imbalances resulting from a sharp increase in the supply of wind energy in the north of Germany and a lack of energy supply in the south due to inadequate capacity on transmission lines. This has been overcome so far through the improved integration of the European grid allowing for electricity imports and exports. However, current saturation of interconnectors, combined with Europe's ambitious plans to increase renewable generation, necessitates a more sustainable solution to maintain balance in both the transmission and distribution portions of the electricity grid (IEA-ESTAP, 2012).

Moving forward, the main challenge faced by the German electric power system will be the local and temporal balancing of electricity supply and demand. While spatial imbalances can be managed or diminished by grid expansion (although this solution faces significant NIMBY concerns (Not in my backyard), trans-regional temporal imbalances must be solved by other means.

This results in a potential solution offered by storage. Either local storage or storage in the transmission and distribution grid. This implies that for short periods and alternating imbalances (excess and lack of energy are alternating problems), electricity storage is a potential solution. This situation is also encountered in other European countries with a geographical mismatch of generation and consumption. Italy for instance is also in this situation, with the Southern regions generating a large amount of intermittent renewable power while the main consumption centres are in the Northern part of the country.

Although distributed generation capacity at consumer level is not expected to largely exceed their consumption, residential areas with high penetration of PV may present specific challenges for distribution networks. PV generation by electricity prosumers may indeed exceed the load during daytime, leading to reverse power flows and potentially requiring higher equipment ratings.

Some demonstration projects in the T&D system have been identified, for instance in Italy where Saft supplied a 2 MW battery to ENEL for one substation located in Puglia, an area with a high level of variable and intermittent power from renewable energy sources that can cause reverse power flows on the high/medium voltage transformers. The role of Saft's batteries in the energy storage system is to reduce the variability of power flow as well as allowing for more controllable energy exchange between the substation and the Italian national grid.

In Germany the solution has been to install local storage at household level.

III.B.4.ii Economic and technological aspects

Increasing CAPEX intensity of networks upgrade. Investment decisions in storage assets for grid support and project location are influenced and triggered by the expected congestion relief and the induced grid investment deferral. Only storage projects relieving efficiently and enduringly congestion are likely to be profitable. There is of course a huge disparity in deferral values depending on the storage location on the grid since this value depends on the costs of the planned network upgrade, as well as on the duration of deferral.

In order to assess the advantages of storage upon grid upgrade, TSOs and DSOs need to perform an extensive analysis of the different revenue streams and more specifically of the benefits derived from investment deferral. Different aspects of the planned investment directly influence the viability of upgrade deferral thanks to the installation of storage assets:

- The estimated T&D upgrade costs over the additional load served thanks to the upgrade that can be defined as the "CAPEX intensity" of the upgrade. This metric brings an understanding of cost of the congestion relief when treated with additional lines. If the geographic specificities of the site require high investment costs (long lines, technical difficulties) and if the projected overload is modest, the CAPEX intensity of the grid upgrade will be costlier. These sites with high CAPEX intensity are the most favourable locations for grid storage.
- The duration of the CAPEX deferral, directly related to the projected overload and the expected demand growth is also important to assess the value of storage.
- The estimated storage costs over the additional load served. This cost assumption needs to be performed on a case by case basis as many features of the demand profile may influence the sizing of the storage assets. Especially, if demand is seasonal and that congestion usually occurs during long periods of time (e.g. weeks), storage will not be competitive compared to new lines. This effect can be partly described with the peak to average demand ratio.

Several projects, operational, under construction or contracted, are developed in the United States in order to provide transmission upgrade deferral benefits (US Department of Energy (DoE)) :

- The Charleston Energy Storage Project aims at mitigating current local capacity constraints and service reliability issues in the short term.
- San Diego Gas and Electric's (SDG&E) is testing different storage systems in different locations. Kokam and S&C Electric are supplying a 3 MWh lithium ion system for Julian Substation. The system will be used for islanding and capacity/infrastructure deferral. Saft and ABB will supply a 3 MWh lithium ion system for the Borrego Substation. The system will be used for power quality and capacity/infrastructure deferral. Greensmith, ABB, and Samsung SDI will supply a 3 MWh lithium ion system for capacity & infrastructure deferral and power quality.

These projects illustrate that grid upgrade deferral can be an important revenue stream if specific geographical and electrical conditions are met. Nonetheless, the overall viability of a storage asset compared to a grid upgrade taking into account only upgrade deferral as revenue is questionable. As the existing projects suggest, the presence of others revenue streams are critical for the overall economic viability of storage.

Importance of the valuation of network reliability services and storage services. Even though grid storage may be beneficial from an integrated, system-wide perspective, it is likely that an efficient scale of storage deployment would not be reached if it can only capture the value of transmission & distribution grid services. Deploying storage assets on specific locations on the transmission & distribution system is indeed important for capturing the value associated with this location (e.g. transmission & distribution investment deferral). However, in many cases, this may not be enough for covering the costs of the asset. As compared to conventional alternatives for congestion relief applications, e.g. new transmission & distribution equipment, storage can provide additional services: mainly improve network reliability and perform other unregulated services (e.g. arbitrage, frequency regulation). The values of these services will vary depending on the case considered but are usually critical to ensure storage economic viability. This situation is illustrated in Figure III-II (The Brattle Group, 2014). In addition to that, considering that storage used for T&D deferral is often needed for just a few tens of hours to 200 hours per year (Sandia National Laboratories, 2010), storage can be used for other services for the very large majority of the year.

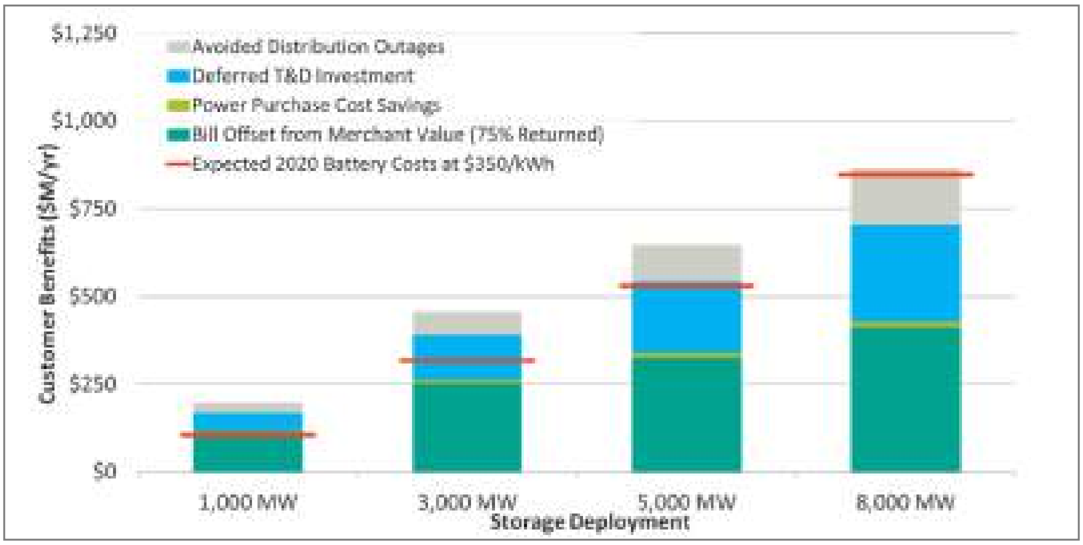

Figure III-II: Example of customer benefits and storage costs for a transmission and distribution system (The Brattle Group, 2014).

Few projects feedbacks are available on the valuation of services other than congestion relief in grid-support cases. However, the following can be expected:

- Network reliability: the value for this service is not expected to change significantly since it remains one of the first objectives of the T&D systems. It can however be critical for the choice of the location.
- Arbitrage: this value is expected to decrease in the future as the grid will be more flexible and prices less scattered.

Significance of technical correct technical comparisons. One generic problem with introduction of storage as a viable technical solution is the complexity of the power system. It is often not possible to make direct comparisons between technical options without conducting in-depth technical analysis. The case to use storage for frequency regulation may serve as an example. Today frequency regulation is carried out by the use of inertia in the system created by rotating masses, and generation that can be controlled fast such as gas turbines. With increasing variable production and also new patterns on the demand side e.g. charging of electrical vehicles there are new factors affecting the frequency stability in the grid.

Storage combined with convertors that can draw power from/to the grid can offer a new solution to maintain frequency. There is one fundamental benefit with the storage solution compared to conventional alternatives and that is the speed of response. CESA (California Energy Storage Alliance) has conducted a study to determine how effective a storage solution can be compared to conventional solutions[32]. The report also identified additional factors:
"Use of conventional resources not only requires more MWs to provide the same service, but can also lead to additional indirect costs that are often not taken into account when comparing systems. For example, the increased cost for ancillary services will put stress on existing equipment leading to additional maintenance costs and potentially reducing generator life."

The effect is summarized as:

How Energy Storage is 2.5X More Effective than Generation

The following provides a simplified example of how energy storage can be two to three times more effective than a combustion turbine.

Assume regulation is only procured from a gas turbine with a 5.1% per minute ramp rate, allowing the turbine to move from zero output to full output in about 20 minutes.[20] Imagine that a system operator experiences a sudden generation loss. To meet NERC requirements, the operator must bring on 25 MW in additional generation within the next ten minutes.[21] In other words, over the next ten minutes, the system operator needs a 2.5 MW per minute ramp rate total from all generators providing regulation. If the only regulation generators are gas turbines with a 5.1% ramp rate, there needs to be 49.1 MW of these gas turbines online to meet the operator's ramp requirement. In contrast, 25 MW of energy storage could provide the full 25 MW of additional power within 20 milliseconds.

The essentially immediate availability of energy storage allows system operators to maintain ACE while providing enough time to call up traditional generators (on spinning or non-spinning reserve) in an orderly manner. In the scenario above, 25 MW of energy storage provided the performance equivalent of 49.1 MW of natural gas turbines, or 1.9 times the amount of generation. The multiplier could be higher (for example, if the system operator didn't find out about the problem until a few minutes later) or lower (for example, if there are faster generators online). Over a wide variety of scenarios and a wide variety of turbine models, studies have found that, on average, energy storage provides 2.5x the performance of a combustion turbine.[22]

Significance of pricing models, development of zonal and nodal pricing. Nodal pricing or locational marginal pricing (LMP) is used in Argentina, Chile, Ireland, New Zealand, Russia, Singapore, in several US states (e.g. California, New England, New York, PJM and Texas), and Poland is on the way to implement it as well (Holmberg & Lazarczyk, 2012). This design acknowledges that location is an important aspect of electricity which should be reflected in its price, so all accepted offers are paid a local uniform-price associated with each node of the electricity network.

Real-time markets with zonal pricing consider inter-zonal congestion, but have a uniform market price inside each region, typically a country or a state, regardless of transmission congestion inside the

[32] The study shows that storage (here assumed to be a flywheel storage but the report concludes that the situation is the same e.g. for battery storage) is the closest to the ideal resource, due to speed of response more efficient than all conventional alternatives such as hydro and - more significantly - 2.5xvmore efficient than gas turbines. A battery solution can thus be much smaller in size (power) to achieve the same effect for frequency regulation.

region. Originally this design was thought to minimize the complexity of the pricing settlement and politically it is sometimes more acceptable with one price in a country/state. This is why zonal pricing was adopted by Australia and by most European countries. Originally, zonal pricing was also used in most unregulated electricity markets in the US, but they have now switched to nodal pricing, at least for generation. One reason for this change in US is that zonal pricing is, contrary to its purpose, actually quite complex and pricing is not very transparent.

These two pricing schemes consider the transmission constraints and allow for possible arbitrage between different zones or nodes. If nodal pricing is developing, decentralized grid storage assets will be able to capture an additional and potentially substantial revenue stream depending on their location on the grid.

Locational marginal pricing gives a solution for improving market efficiency in terms of delivering an “instantaneous” dispatch that reflects the demand and supply situation at the nodes in the grid as well as the underlying physics of the network itself. Although the theoretic principles are clear, a study performed by the Norwegian government (Finn Erik Pettersen, 2011) shows considerable variation with respect to the practical implementation of these principles in existing nodal markets and the consequent implications for the functioning of these markets.

The actual development of zonal pricing, along with the development of smart grids in Europe will require strong commitment of governments and regulatory changes. However, in Europe, countries tend to favour investments that help to establish one national electricity price and many national projects help to increase capacity for international trade (Katharina Grave, 2015).

Development of demand management. Decentralized grid storage used for congestion relief is likely to compete in the future with distributed storage used for demand-side management in smart grids. Distributed storage used for demand-side management will enhance grid flexibility and lower the need in the future for congestion relief.

Whether in the form of direct load control or real-time pricing, demand-side management (DSM) should be an essential ingredient of future smart grids. As many small scale storage assets are implemented on numerous locations on the grid, it creates a diffuse storage capacity that improves the flexibility and reliability of the energy system, absorbing some shock on generation mix and on demand load, therefore decreasing the constraints on the distribution and transmission networks.

Many pilot studies have been carried out to study demand response (DR) in the US and more recently in Europe. The initial conclusions suggest that peak load-shedding may be significant (Claire Bergaentzléa, 2013).

Development of smart grids and demand management will likely increase load shifting and consequently relieve constraints on the network. This development is likely to appear in North American markets and in Europe in the long term.

III.B.4.iii Social and environmental aspects

Increased environmental and social opposition to new infrastructures. New infrastructure construction face increasing opposition and acceptation hurdles from a wide range of stakeholders. The resulting delays in the construction of new infrastructure may then favour storage as a possible temporary solution as their implementation schedule is expected to be lower. However, security issues linked to storage systems may also lead to local oppositions that could threaten their implementation.

Opposition to new infrastructures spreads all over Europe for a variety of reasons. This concerns all types of infrastructures and often results in permitting and/or construction delays for these infrastructures. This phenomenon would favour more compact solutions with smaller footprints such as storage solutions.

However, storage also encounters acceptability issues. For instance, in the case of electrochemical storage systems:

- Some battery technologies include hazardous materials (e.g. lead-acid batteries) or even toxic.
- Some technologies may feature industrial risks (explosions, fires, etc.)
- Some technologies use relatively rare materials (e.g. lithium) that are exposed to critical debates.

According to ENTSO-E, more than one third of the investments of pan-European significance contained in their Ten Year Network Development Plan (TYNPD) 2012 are delayed compared to the initial schedule and most of the projects featured in the TYNDP 2014 (ENTSOE, 2014) that have entered the permitting process have experienced delays. The main causes for these delays are social resistance and longer than initially expected permitting procedures. They note that the phenomenon is not specific to certain countries or regions.

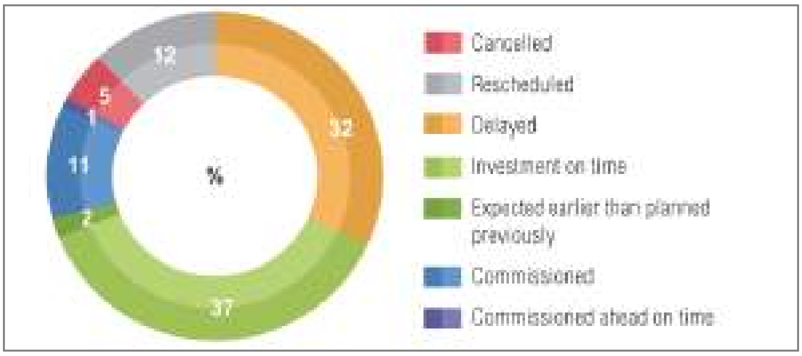

Figure III-III: Evolution of ENTSO-E's Ten Year Network Development Plan 2012 portfolio (ENTSOE, 2014)

It is difficult so far to weight the relative impact of this phenomenon and to determine whether it would favour storage over alternative solutions, although storage appears slightly advantaged. Anyway, opposition is expected to follow an upward trend for all alternatives over the next years.

III.B.4.iv Legal aspect

Easier legal access to storage assets construction and operation by SO in unbundled markets. For the development of grid scale storage project, one fundamental question is whether or not a TSO or DSO can build and operate an energy storage asset, and seek cost recovery through regulated as well as unregulated revenues. This issue, deriving from the application of the ownership unbundling principle, will greatly influence the development of storage assets for grid support as TSOs and DSOs in Europe and in countries where liberalization of electricity markets has occurred.

Figure III-IV: TSO status in EU, from (RTE, 2012)

According to Article 9 (1) of the Electricity Directive, a TSO cannot have any type of control over an electricity generation facility. Therefore, to the extent that electricity storage is treated within the regulatory framework as generation, a TSO cannot have any control over an electricity storage facility (STORE, 2013), and this situation does not change with the OU, ISO and ITO structures. The intention is to prevent incentives for abusive behaviour in the market, where for example an electricity generation facility owned by a TSO could have an advantageous treatment compared to a generation facility owned by a third party. This particular feature prevents any TSO or DSO in Europe from owning storage assets, hindering the development of storage as an alternative to the construction of new lines. This situation is similar in other countries such as Australia where OU principle is respected. In a study from the World Bank on power markets structure (Vagliasind & Besant-Jones, 2013), different levels of unbundling are described. In fact, different forms and level of horizontal and vertical unbundling exist. They can be categorized in ascending extent of reform:

- Vertical integration
- Vertical integration with IPPs (Independent Power Producers)
- Some extent of vertical and horizontal unbundling
- Extensive vertical and horizontal unbundling
- Power market

Fully vertically integrated monopolist markets or vertically integrated monopolist markets with IPPs, in which TSOs and DSOs are power producers and retailers, and can own storage assets, are dominant in Sub-Saharan Africa (84%), in South Asia (74%), in Middle East and North Africa (67%) and East Asia and the Pacific (83%). On the contrary, power markets or markets with unbundling of TSOs are dominant in Latin America and the Caribbean (69%) and in Eastern Europe and Central Asia (60%).

In countries respecting an unbundling principle, the legal framework is a clear barrier to the development of storage assets for grid support as the main stakeholders, TSOs and DSOs cannot directly benefit from it and must implement it using an independent third party. In vertically integrated markets, the construction and operation of storage assets for grid support is more straightforward but still requires analysing the benefits of investment deferrals, security supply and other ancillary services.

In the EU, every country respects an unbundling principle preventing any TSO or DSO to own and operate storage assets. For implementation of storage assets on the grid, only two solutions exist:

- In the case of an ISO structure, the owner of the transmission assets is allowed to implement and run storage assets. However, this scheme doesn't give any incentives for investments.
- In the case of an ITO or OU, the only legal possibility is for a TSO to contract an independent storage operator that will invest and control the storage asset for the TSO.

However, there is still legal uncertainty regarding the effect of the unbundling principle on electricity storage. In Italy, TERNA (the Transport System Operator) obtained the right to build and operate "movable storage systems" (legislative decree 01/06/2011, n°93, also applying to Distribution System Operators). This concession to the European unbundling policy has a limited scope of application: the system must ensure the security of the national electricity system and its proper functioning, maximum use of renewable energy sources and procurement of resources for dispatching services. For now, the regulatory framework has been adapted by the Italian regulation agency (AEEG) for the purpose of TERNA's grid-scale battery trials. On the other hand, TERNA has not been authorized to operate Pumped Hydro Storage plants.

In Texas, the utility ONCOR, which owns the state's largest electrical grid, made a proposition to change the rules of the Electricity Reliability Council Of Texas (ERCOT) market (The Brattle Group, 2014). The envisaged policy would both enable T&D operators to invest in energy storage assets, as part of their regulated activity, and to "auction off" to independent third parties the wholesale market dispatch. This approach would maintain the clear delineation between the T&D operator's regulated role and wholesale market participants.

Eventually, ENTSO-E, in its Ten Year Network Development Plan (ENTSOE, 2014) states that "*the possibility to install storage plants on the transmission network by TSO is strictly connected to improve and preserve system security and guarantee cheapness of network operation without affecting internal market mechanisms and influence any market behaviour*", therefore implying that only network services (investment deferral and supply security) are accessible to TSOs, and not market services. Future evolutions of the legal framework concerning unbundling principles of TSO and storage assets will be critical for the development of T&D storage.

Future regulatory decisions regarding TSOs and DSOs ability to own and operate storage assets on the grid and to earn regulated and unregulated revenues would be a game changer for grid scale storage in the European Union and in other countries with an unbundled power market. In vertically integrated markets, future unbundling of TSOs may also greatly impacts investment and revenues schemes as well as projects viability.

III.C. Battery storage in households

Battery storage in households represents a particularly interesting emerging application. There are currently three obvious applications:

- Increase self-consumption in conjunction with local production, usually with PV panels
- Save on energy costs by shifting load to low cost time from high cost time
- Save on power tariff by reduction of peak power

To increase the value of a home storage a combination of benefits is naturally what is most beneficial. But there is may also be regulatory hurdles that makes the "battery case" less attractive for all these categories for example:

- Net metering tariffs for PV panels drastically reduces the business case for self-consumption
- Saving on energy cost requires hourly metering and billing. This is only the case on a few markets in Europe
- The lowest power tariff can be much higher than the achievable max power level

Some case studies will illustrate the potential business cases.

III.C.1. Germany, increased self-consumption

Germany implemented a support system for home storage when combined with PV Solar, amounting to 30% of the investment up to a value of 3,000 €. The support system created an immediate market boost and in 2013, about 6000 batteries with a total capacity of 50,000 kWh. A small fall in the market is expected in 2014 but after that, the market is expected to grow very fast. Although the initial market has been dominated by home storage, larger commercial systems will increasingly install battery storage. The predicted market development in the shows that the market is expected to have stabilized in 2018 with 100,000 units per year, and that in 2020 the accumulated market will be about 500,000 batteries. It is expected that the market will increasingly involve retrofitting of existing PV installations with batteries (see Figure III-V)

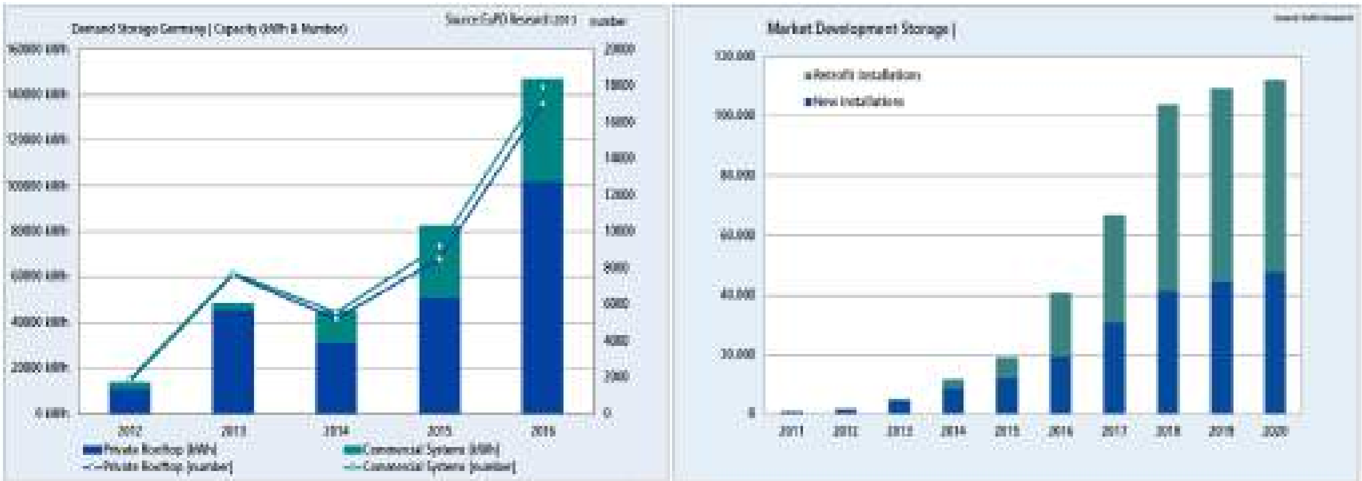

Figure III-V: Battery development in Germany

The business case in Germany is attractive already today based on existing support schemes but more interestingly is that with expected development of electricity prices and battery prices the "battery case" will be positive within a few years according to recent studies (see Figure III-VI)

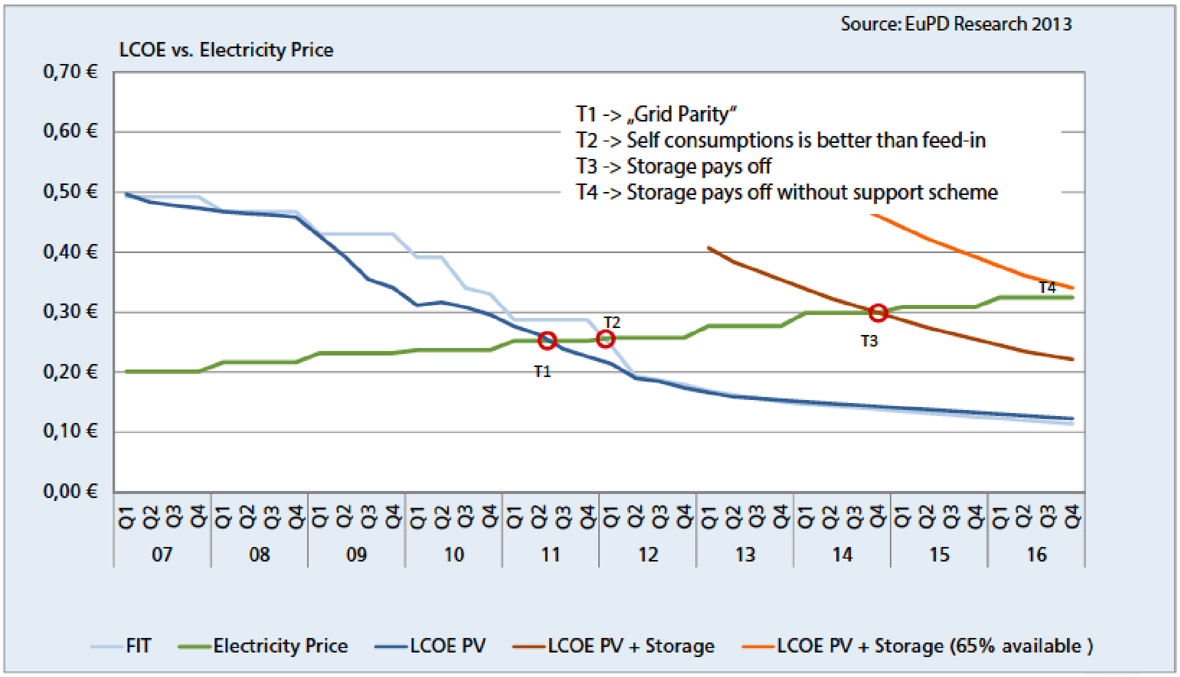

Figure III-VI: LCOE vs. Electricity in Germany

III.C.2. Sweden, energy arbitrage and reduced power tariff

Sweden has introduced hourly billing that makes it possible to immediately capture the benefits of shifting load during the day. That is the good news. The bad news is that electricity prices are very low and this limits the benefits from energy arbitrage. There is potentially more value in reducing power. Here the problem is that the lowest power tariff normally offered is based on a 16 A fuse size. To capture the benefits of power reduction, there are at least three possible solutions:

- Bundle a number of apartments. This is very possible in many cases since there is a special scheme in place with local "corporations" with typically 10 to 100 apartments.
- Change regulation to mandate lower tariffs
- Distribution companies can decide to incentivise lower power and thereby reduce their costs for grid expansion. This is done on a few places where the fixed tariff for power (fuse size) is replaced by a scheme where the actual peak load is measured and charged to customer on monthly base.

To get an idea of the potential business case with a home storage battery in Sweden a simulation has been done based on average load profiles and assuming a model where reduced power is regarded. The simulation shows that the potential value of power reduction is higher than the value of shifting load. The total value is about 200€ per year and the required battery size is 2 kWh. With current battery prices there is no business case, but with the reduction in battery prices and expected development of electricity prices Sweden is expected to be an interesting market for home storage.

Characteristics of a typical Swedish household

A typical Swedish household[33] living in an apartment has the following characteristics:

- Annual consumption without electric heating: 3,000 kWh
- Main feeder: 1 x 220V; 20A; 4.4kW max power
- Daily energy consumption average: 8.2 kWh
- Daily average power average: 0.34 kW (7.7% of max power)

Sweden has a very low average utilization of the available grid power (between 6-10% based on typical main fuse and average energy consumption), and a well-developed electricity market with hourly metering and billing of electricity. A typical high load pattern together with daily variation of the electricity price is given in Figure 1 and Figure2:

Figure 1: Typical daily load pattern in Sweden (Hansson, 2014)

Figure 2: Daily variations of electricity prices in Sweden (Hansson, 2014)

A local energy storage with a capacity of only 2 kWh could be used to completely flatten the power drawn from the grid or minimize the electricity tariff by shifting load to low price times. The chart below illustrates a case with a complete flattening of the load:

[33] The average size of household in 2013 in Sweden is 2.1 persons, according to Eurostat. In Sweden the average annual consumption per household is much higher than the European average (i.e. approximately 9,000 kWh versus 4,000 kWh).

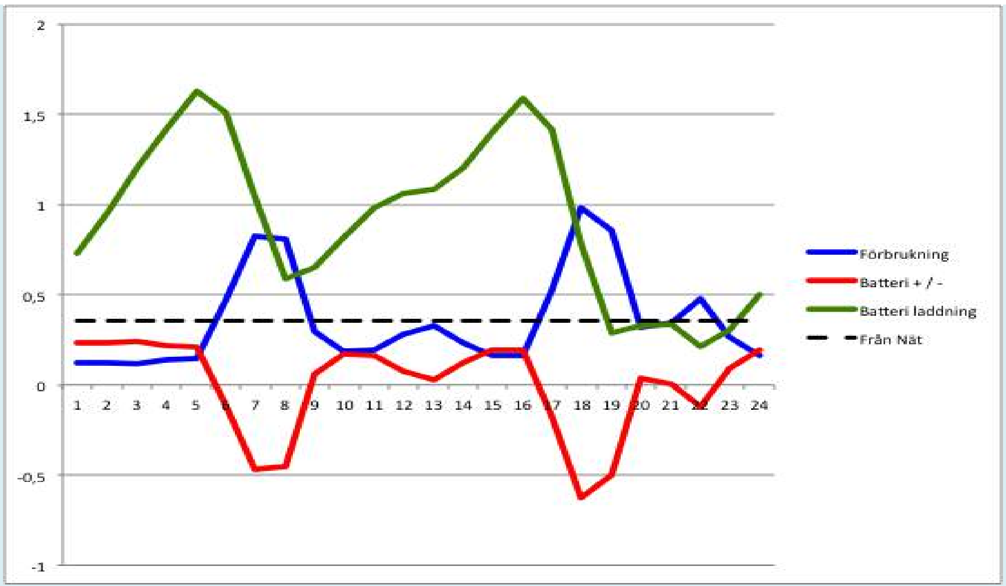

Figure 3: Levelling out loads with batteries. **Blue**: consumption; **Red**: Battery charge/discharge; **Green**: Battery charge level: Dotted: from grid. (Hansson, 2014)

According to this data, the potential value of the storage can be calculated, and shows the following annual benefits:

- Reduced power tariff (-3 kW): **100 €**
- Reduced energy fee: **90 €**

It should be mentioned that the current tariff structure does not allow for a reduction of the power tariff below 3.5 kW, which is the minimum tariff.

IV. Legislative framework

The past legislation analysis sets the main principles and guidelines, based on which flexible production facilities have been operating in the past. It also brings forward the case of storage in infrastructure regulation.

IV.A. What lessons can be learned from the past legislative framework?

IV.A.1. EU legislation

Since the end of the 1990s, different waves of market reforms have taken place in the European energy sector, leading to the progressive opening of markets to competition. In the 2020 Climate and Energy Package[34], the application of the unbundling principle[35] to the electricity sector, does have important consequences in terms of ownership of flexible production facilities.

The principle of unbundling, refined in Directive 2009/72/EC under Article 9, explicitly states that a TSO cannot control supply or generation of electricity, as this could create market distortion and interference with system wide responsibility. As a result, this principle constraints large scale storage development on the grid. However, this may not apply to small scale storage, which size and volumes shall be associated with lower risks of market interferences.

IV.A.2. The case of storage

In infrastructure regulation, Regulation (EC) 714/2009 (Article 8) created the Agency for Cooperation of Energy Regulators (ACER), and the European Network of Transmission System Operators for Electricity (ENTSOe)[36], both acting together in the creation and adoption of framework guidelines and the definition of network codes, according to a specific timeline and working plan among the parties. ENTSOe's proposed a cost benefit analysis for storage projects above 225MW, allows to assess storage projects in the selection procedure of Projects of Common Interests[37]. This procedure is based on specific criteria including, among others, security of supply, reduction of transmission losses, but not including flexibility.

Under the existing legislation (EU Third package[38]), there are no specific definition of flexibility, nor specific indication, as to how and under which conditions, flexibility should develop in the market.

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[34] The Climate and Energy package includes the following texts: Regulation (EC) No 443/2009 - Reduction of CO2 emissions from Light Duty Vehicles / Directive 2009/28/EC – Renewable Energy Sources / Directive 2009/29/EC – Emission Trading Scheme / Directive 2009/30/EC – Fuel Quality Directive / Directive 2009/31/EC – Carbon Capture and Storage / Decision No 406/2009/EC – "effort sharing".
[35] Full ownership, legal, management (or "functional") unbundling.
[36] The ENTSOe covers 41 Transmission System Operators from 34 countries.
[37] http://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest
[38] The Climate and Energy package (1)

IV.B. What lessons can be learned from the present and progressing legislative framework?

The present legislation analysis focuses on energy storage, where national legislative frameworks have been built relative to the operation of Pumped Hydro Storage. Existing legislation related to large scale Pumped Hydro Storage (PHS) is consisting mainly of its participation in the electricity wholesale generation market, but there are some attempts to make PHS functioning according to flexible requirements of the grid (IV.B.1). The issues related to legislative barriers in EU legislation will be dealt in later parts of WP4 dealing with future legislation.

Common rules related to grid Network Codes are important pillars that need to be addressed, together with market design evolutions (IV.B.2). The Spanish country case is referred to, in order to evaluate the progress made in countries with high shares of renewables sources. Finally, flexible production related to distributed generation, distributed storage, finds some legislative backgrounds in the Energy Efficiency Directive (2012/27/EU).

IV.B.1. Legislation relative to the operation of Pumped Hydro Storage (PHS)

Beside general economic conditions, the decision to build a PHS site is also dictated by topographical, geographical, and environmental legislation; that may constitute important aspects, and, are not discussed in this section.

As opposed to hydro dams (run of river and reservoir based), PHS is not classified as Renewable Energy Source (RES) as the energy used to pump the water from the lower reservoir is drawn from the electricity grid[39]. As a consequence, PHS are not eligible for RES incentives' schemes and RES priority dispatch[40]. Any incentives for investments in PHS should be conformed to EU State Aid Guidelines and be justified by supply of security issues and evaluated against interconnections options.[41]

In the UK, the remuneration of low carbon electricity generation[42] developed as part of the electricity market reform, and approved by DG competition[43], does apply to hydro and different forms of low carbon and flexible production means (Wind, Solar, biomass, CHP). However, they do not apply to PHS.

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[39] Average efficiency ranges from 70-80%.
[40] RES Directive: Directive (2009/28/CE)
[41] SWD(2014) 139
[42] Contracts for Differences, https://www.gov.uk/government/collections/electricity-market-reform-contracts-for-difference
[43] http://europa.eu/rapid/press-release_IP-14-866_en.htm

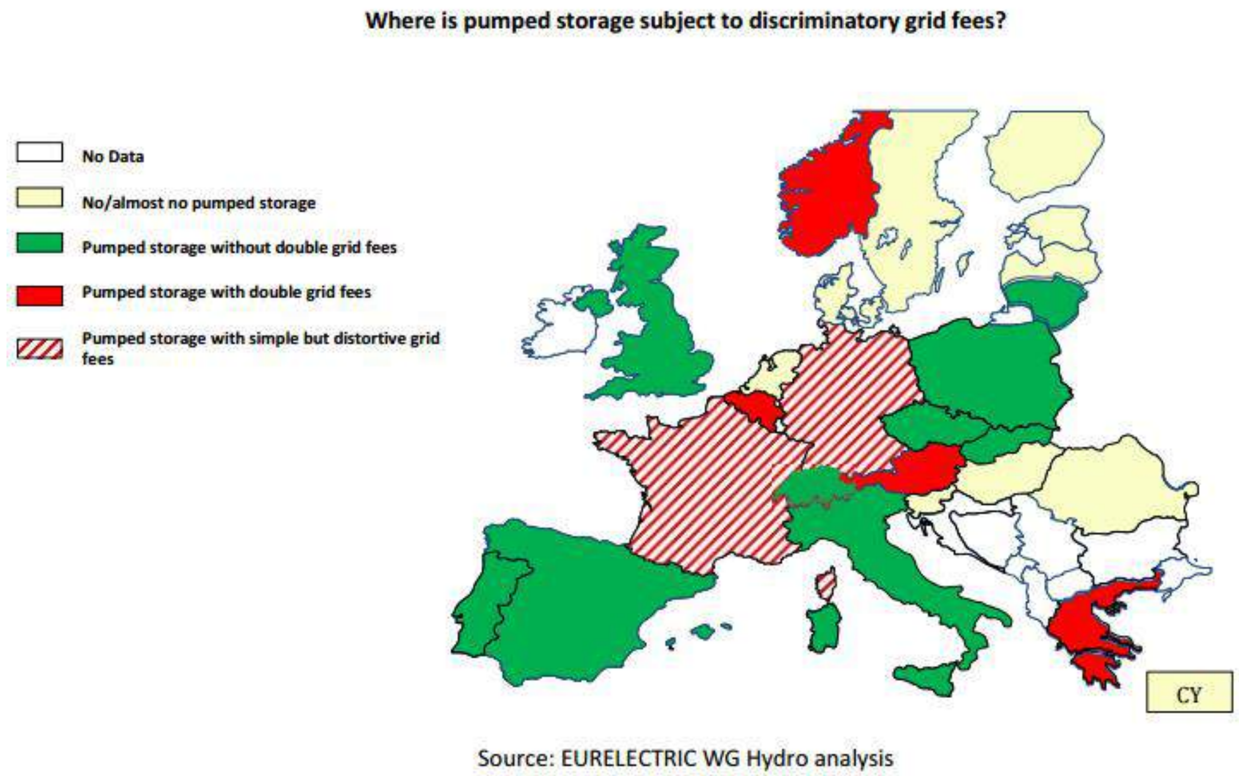

Figure IV-I: Pumped Hydro Storage: Treatment of grid fees

Beyond the transposition of EU Directives in national legislation, there is a diverse framework of rules applicable in the different EU Member States[44]. The majority of PHS are owned by utilities or project developers. For instance, in France, PHS is considered as a public-private asset under a concession regime[45], awarded through competitive tender, where there is a transfer of ownership between the State and the concession owner (i.e. the utility or project developer).

Throughout the EU, Pumped Hydro Storage has been mostly defined by existing legislation and regulation as a "generation" technology. Essentially, PHS were deemed to complement and store base load production of nuclear and hydro, through energy arbitrage[46].

However, PHS dimensioned with variable or adjustable speed turbines are allowed to provide up and down grid services regulation to TSOs and DSOs, and appear well suited for the provision of balancing services (balancing energy or capacity), outside of the intra-day market; as well as for other grid services (frequency regulation, load support services). In these markets, they may act in combination with other flexible generation power plants.

[44] Eurelectric Study: Europe needs Hydro Pumped Storage – 5 Recommendations – May 2012
[45] PHS are operated under a concession regime like other hydro assets of more than 10 MW, under a 30 to 50 years' duration.
[46] Buying electricity at off-peak prices and selling at peak prices.

IV.B.2. Network codes and market design legislation

In the implementation of the Third Package, ENTSOe is to elaborate a number of grid codes defined as a set of rules for system operations and market integration, and based on the Agency for Coordination of Energy Regulators' (ACER) framework guidelines. Grid related regulation is to be transferred into binding EU law through the "comitology" procedure, after consultation with the ACER. Network codes are an important part of the legislation that will open pathways or alternatively create barriers for storage technologies, both in the electricity system operations framework and the electricity market design.

System Operations Framework

Among the ten different codes[47], the Network Code on Load-Frequency Control and Reserves (LFCR) will have a direct impact on the functionalities that some flexible production asset can provide to the system, as it will be a key determinant of activation of facilities, in particular through a common methodology for Restoration and Replacement Reserves (FCR and FRR). Under ENTSOe's final version of the LFC&R[48] code, only in extreme circumstance, like in emergency cases, can large scale storage Pumped Hydro Storage be activated, as an alternative to load shedding, in order to correct frequency deviation, support final customers' and supply stability and continuity.

Electricity Market design

Capacity allocation and congestion management guidelines (CACM), and the forward capacity allocation (FCA) code, define, together, with the code on electricity balancing (EB), the "Electricity Target Model", a set of rules and actions, which are aimed at facilitating the participation of demand side response including through aggregation facilities and energy storage.

The electricity market design, as set out in the CACM Guideline is based on four elements: – A day-ahead–wholesale market for energy and transmission capacity; – Intraday markets; – A coordinated approach to capacity calculation – including implementing the "flow-based" method – with the objective of making the best use of the electricity transmission lines which interconnect Europe; – The definition of a series of bidding zones on the basis of transparent criteria reflecting both system security and the need to promote competition.

Sources: ENTSOe

Common rules on balancing, are elaborated under the Network Code on Balancing (Network code EB[49]), towards an integrated "TSO-TSO model" with a common merit order. In this Network Code,

[47] Capacity Allocation and Congestion Management (CACM); Forward Capacity Allocation (FAC), Electricity Balancing (EB), Requirements for Generators (RfG), Demand Connection (DCC), HVDC Connection (HDVC), Operational Security (OS); Operational Planning and Scheduling (OPS), Load Frequency Control and Reserves (LFCR), Emergency and Restoration (ER)

[48] The network code LFC&R provides the codes for reserving capacity and possible sharing of reserves or exchanging of reserves between TSOs

[49] https://www.entsoe.eu/major-projects/network-code-development/electricity-balancing/Pages/default.aspx

demand facilities, aggregators and generation units from conventional and Renewable Energy Sources, as well as storage elements, shall be allowed to become Balancing Service Providers. The Network Code on Balancing recognises storage facilities as an active participant in electricity balancing, although it does not give a precise definition of storage.

According to the EC Summer Package[50] consultation, intraday and balancing markets constitute the core aspects of the proposed electricity market design reform, including at EU cross-border levels through improved market coupling between Member States. According to the consultation, integrating storage would improve the flexibility of the electricity market and ultimately enhance its security. This consultation opens one main avenue for storage to develop as a market based instrument in the wholesale market, and through long term infrastructure investments. In the future, storage could also become an essential element of grid stability and security.

RES generation forecasting and balancing obligation for RES producers

RES generation forecasting is becoming critical and balancing obligation for RES producers are being discussed in some Member States. One country case in Spain is referred to evaluate the progress made in countries with high shares of renewable sources. Spain has successfully integrated a large penetration of renewable resources into its power system, equivalent to 15% of electricity produced in 2013[51].

According to the Royal decree RD 661 from 2007[52], Spanish electricity producers from wind energy can choose between two options of remuneration. According to Article 24.1 of the Decree the producers can choose between: a) a regulated tariff for all periods of the production program or b) a guaranteed premium on top of market price. **The price regulation system is currently phased out through Real Decreto-ley 9/2013**.

In both cases, the electricity producers must submit a production program to the TSO and in case of deviations, the producers are penalized according to specific formulas. This market solution has allowed the TSO to keep the volume of required balancing services constant in the last years, despite the large penetration of wind power in Spain and the limited interconnection with neighbouring countries.

Because of the fact that renewable electricity producers can be charged imbalance prices for the difference between their planned electricity production and their actual electricity production (the total imbalance volume), similarly to conventional electricity producers; renewables electricity producers are encouraged to accurately forecast their expected production.

IV.B.3. Legislation on communication and data management

Directive 2009/72/EC explicitly states that TSOs have to procure energy for covering energy losses and reserve capacity on a transparent, non-discriminatory and market-based manner; the same

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[50] COM (2015) 340 final
[51] Shares Model Results 2012
[52] REAL DECRETO 661/2007, de 25 de mayo, por el que se regula la actividad de producción de energía eléctrica en régimen especial

applies to TSOs in case of balancing the electricity system. This constitutes an important guarantee for flexible production to operate in a transparent environment.

According to the mentioned Directive, TSOs, DSOs, and other market participants have responsibilities regarding, inter alia, data exchange in order to establish transparent and well-functioning electricity markets. TSO's are already obliged to publish data on aggregated forecast and actual demand, availability, on use of generation and load assets and on availability and use of the networks and interconnections, as well as on balancing power and reserve capacity, as stated in Regulation (EC) No 714/2009. Also, all market participants are to provide the transmission system operators with relevant data. This regulation also defines mandatory cooperation regarding elaboration of network codes, common network operation tools, development plans, technical cooperation, annual work programmes, annual reports and annual summer and winter generation adequacy outlooks.

IV.B.4. Legislation supporting decentralisation

Legislation on combined heat and power together with support schemes for Prosumer batteries in Germany provide examples of existing legislation favouring flexibility at local levels.

Combined Heat and Power Schemes

Flexible production related to distributed generation, distributed storage, already finds some legislative backgrounds in the Energy Efficiency Directive (2012/27/EU), aiming to ensure the achievement of the EU's 2020 20% target on energy efficiency. In order to achieve this goal, the Directive is supporting specific technologies with high levels of efficiency and high degree of fuel flexibility, like broader CHP technologies and micro-CHP used in residential and commercial buildings.

In EU legislation, the Combined Heat and Power (CHP) Directive (2004/8) is set to promote CHP and cogeneration technologies, that provide a high energy efficiency and flexibility in fuel uses. The CHP Directive has been repealed by the Energy Efficiency Directive (2012/27/EU)[53] supporting the 2020 energy savings targets[54], together with CO2 emissions reductions targets (100 Mt CO2 per year) and decreases in network losses. The Energy Efficiency Directive also improves the landmark framework for micro-CHP and requires each EU country to carry out a comprehensive assessment of its national potential of cogeneration and district heating and cooling (a main user of cogeneration) by December 2015.

Prosumer Batteries

The German development bank (KfW) initiated a support program for battery storage systems in May 1st 2013. This program provides low-interest loans and repayment subsidies for solar photovoltaic (PV) installations which incorporate a fixed battery storage system. Among the technical requirements, the facilities should include new PV system or provide retrofit to solar PV system commissioned, after 31st December 2012, with grid supporting functions. The scheme applies to solar systems of maximum

[53] Support can only be granted to cogeneration plants that save at least 10% of primary energy fuel compared to separated means of heat and electricity production (high efficiency cogeneration plants).
[54] Combined heat and power or cogeneration contributes about 2% towards the 20% annual primary energy savings objective for 2020.

30 kWp, and provides an effective power reduction to 60%. The subsidy is equivalent to $660/kw of capacity. The installed based grew from 8.000 systems in 2013 to above 15.000 end 2014. Still, the investment remains heavily taxed and subject to grid fees when the battery is charging and discharging.

Energy Efficiency Directive

The Energy Efficiency Directive is also requiring to remove barriers and market failures derived from network regulation and tariffs. In Annex XI of the Directive[55], it is recognised as a factor important for services for demand response measures, demand management and distributed generation in an organised electricity market. In this annex of the Directive, storage is mentioned as a specific service provided in the electricity market, under network regulation, and therefore not as electricity generation.

IV.B.5. Environmental legislation affecting storage development

This paragraph details the relevant environmental EU legislation affecting storage development in the case of hydropower (pumped hydro storage). These legislations have been developed in the face of rising environmental opposition to infrastructure projects.

The most important piece of water-related legislation is the Water Framework Directive – WFD **(Directive 2000/60/EC)** covering the expanded scope of the water protection to all surface waters and groundwater. One of the requirements of the WFD is the principle of non-deterioration, which requires the prevention of the deterioration of water status. There exist exemptions to this principle (WFD Art. 4.7) which are of specific relevance for new modifications to the physical characteristic of water bodies (new infrastructure projects, including hydropower). Furthermore, the "polluter pays" principle needs to be considered, requiring that the party (e.g. the hydropower plant operator) responsible for the environmental impact, pays for the damage done to the environment according to the costs it generates.

Other environmental legislation regarding hydropower development comprises of the EU Birds Directive and the Habitats Directives, the EU Biodiversity Strategy, the EU Floods Directive, as well as the EU Environmental Assessment Directives.

The overall objective of these directives is to ensure that the species and habitat types they protect are maintained and restored to a favourable conservation status throughout their natural range within the EU.

The EU Biodiversity Strategy to 2020 sets out a policy framework to halt the loss of the EU's biodiversity, this is one of the key operational objectives of the EU Sustainable Development Strategy (SDS) and is recognised as an important element of Europe 2020 Strategy.

Two other key pieces of EU environmental legislation are directly relevant to hydropower developments: Directive 2001/42/EC on the assessment of the effects of certain plans and

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[55] According to annex XI, 2., "Network regulation and tariffs shall not prevent network operators or energy retailers making available system services for demand response measures, demand management and distributed generation on organised electricity markets, in particular: […] the storage of energy".

programmes on the environment (SEA Directive) and Directive 2011/92/EU on the assessment of the effects of certain public and private projects on the environment (EIA Directive) - as amended by Directive 2014/52/EU.

> The **EIA Directive** operates at the level of individual public and private projects. The EIA Directive distinguishes between projects requiring a mandatory EIA (so-called "Annex I projects") and those where Member State authorities must determine, in a procedure called "screening", if projects are likely to have significant effects, taking into account criteria in Annex III of the Directive (so-called "Annex II projects"). All installations for hydroelectric energy production are Annex II projects while projects that fall under Annex I include those for "dams and other installations designed for the holding back or permanent storage of water, where a new or additional amount of water held back or stored exceeds 10 million cubic meters'.

IV.B.6. Legislation in progress

National capacity remuneration mechanisms (CRM) have been developed in the different Member States in order to cope mostly with national electricity systems requirements. For instance, the UK's response, in the framework of the Electricity Market Reform, was mainly to deal with a lack of base load capacity. The German capacity scheme is to cope with large shortage of capacity during a reduced number of hours due to large renewables feed-ins.[56]. Meanwhile in France, national issue at stake is more the dependence of peak demand to weather variations. All these schemes include the participation of the TSO and/or National Regulatory Authority in the evaluation of security of supply concerns and in dealing with emergency situations.

In November 2012, the EU Parliament's Industry, Research and Energy Committee requested the Agency for the Cooperation of the Energy Regulators (ACER) to issue an opinion on capacity markets. Because of the fact that there is currently no uniform approach of capacity remuneration across Europe, ACER is of the opinion[57] that in an integrated European energy market, security of supply cannot be just a national concern and should be addressed at European, or at least regional, level.

The recent State Aid Guidelines on aid to generation adequacy grant the possibility to give supports (Feed In Tariffs for instance) only when alternatives have been evaluated. In the "aid for generation adequacy" exemption category, Member States are required to propose capacity remuneration mechanisms, in so far that these mechanisms also provide incentives for other substitutable technologies, demand response, and electricity storage.

IV.B.7. Electricity generation: Capacity payments in different Member States

The following part details capacity markets' main features in some key Member States. It highlights the main characteristics of the schemes (centralised vs decentralised), their legislative foundations and timing for implementation. As seen through the various approaches detailed above, capacity

[56] CEEM Working Paper 2014-8: "First principles, market failures and endogenous obsolescence: the dynamic approach to capacity mechanisms", Chair European Electricity Markets, Paris Dauphine.
[57] See ACER Opinion n°05/13 - February 2013 and report in July 2013.

mechanisms designed for coping with security of supply under specific national circumstances, may favour peaking flexible production (CCGTs) in the EU electricity market, but it is not certain that it will favour operational flexibility of the plant supporting RES integration in the intraday market. Only UK and France have designed their schemes with an objective to trigger demand response. Most schemes are influenced by national considerations, including the need to fund investments in generation capacities, as requested by utilities in the case of Germany. Capacity markets require the oversight of TSOs, not only in assessing the level of security of supply at local and national level, but, also in ensuring the secure and efficient execution of the capacity market.

UK: Centralized auctions for new and existing capacity[58]

The UK Government decides the amount of capacity it is seeking, based on an analysis from the British TSO, the National Grid and a reliability standard. Pre-qualified capacity will enter competitive central pay as clear auctions run by the National Grid. Successful bidders (including bidders for demand side response) are awarded "capacity agreements", that will provide a steady payment for capacity in return for a commitment to deliver/reduce energy when required in the delivery year. In case the delivery does not take place, a penalty linked to the value of the lost load can be given. The costs of capacity agreements will be met by suppliers based on their market share[59].

The Office of Gas and Electricity Markets reports on Electricity Capacity Assessment to the Secretary of State for the Department of Energy and Climate Change every year[60]. The Electricity Capacity Assessment estimates a set of plausible electricity de-rated capacity margins that could be delivered by the market over the next five winters and the associated risks to security of supply.

France: decentralized capacity obligations

Each supplier of electricity to the French market is under an obligation to hold a certain amount of capacity guarantees, calculated each year, based on the peak consumption of its clients[61].

The French transmission system operator (RTE) grants capacity guarantees to operators of generation facilities, based on their ability and contractual commitment to help meet peak demand. Until a specified date (set yearly by RTE) the capacity guarantees can be traded. The electricity suppliers that fail to justify that they hold sufficient capacity guarantees can be subject to a penalty up to the amount of the cost of building a new capacity. Operators of the certified capacities will be subject to a penalty to the cost of building a new capacity[62].

France is considering implementing a capacity market itself in Winter 2016/2017. The French Law decided the implementation of a Capacity Market, stressing the responsibility of Electricity Suppliers for Capacity Adequacy.

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58 http://www.legislation.gov.uk/ukdsi/2014/9780111116852/contents
59 http://linklaters.com/pdfs/mkt/london/6883_LIN_Capacity_Markets_Global_Web_Spreads_Final_1.pdf
60 https://www.ofgem.gov.uk//electricity/wholesale-market/electricity-security-supply
61 http://www.ceps.eu/sites/default/files/EU_Recent_developments_1.pdf
62 http://linklaters.com/pdfs/mkt/london/6883_LIN_Capacity_Markets_Global_Web_Spreads_Final_1.pdf

The Decree[63] in Council of State for application of the NOME law[64] establishes a regulatory framework specific to the capacity mechanism and specifies the roles and responsibilities of actors[65].

Germany: Reserve mechanisms

Germany's re-dispatch and winter reserves[66] are based on the assessment made by the Bundesnetzagentur (BNetzA) of the country's generation capacity. Plant operators may then express their interest to provide reserve generation capacity. In each balancing areas, TSOs must enter into reserve power supply agreements with these plant operators that expressed interest to provide reserve generation capacity[67].

German utilities companies are in favour of a market wide mechanism[68], that would support new investments in new plants in Germany; Europe's biggest energy market[69].

Austria: No capacity market

Currently, neither the country's energy industry, nor the authorities see capacity mechanisms as a solution.

"According to the Austrian energy regulator E-Control, the security of supply in the Austrian electricity sector can be ensured without further interventions in the market,"[70]as stated by the country's Ministry of Economics. Oesterreichs Energie, the association of Austrian electricity companies, is also of the opinion that Austria will be able to get by without introducing a capacity market in Austria. The ministry is working closely with neighbouring countries regarding their capacity market plans as it believes that Austrian energy companies may be able to offer balancing capacity to the neighbouring markets.

Italy: Capacity Payments

Italy currently has a system of temporary capacity payments[71], while centralized auctions for reliability options are currently under consideration.

Each year, the Italian operator for electricity transmission (Terna) assesses the critical periods requiring excess generation capacity. It selects the providers that are willing to offer their power capacity in these critical periods. In case a provider fails to generate the offered capacity, the Italian Regulatory Authority for Electricity Gas and Water (AEEGSI) can impose a fine ranging from €25,000 per MW to €50,000 per MW[72]. The cost of the capacity mechanism is borne by the end consumers through the electricity bill.

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[63] http://legifrance.gouv.fr/affichTexte.do?cidTexte=JORFTEXT000026786328&dateTexte=&categorieLien=id
[64] http://legifrance.gouv.fr/affichTexte.do?cidTexte=JORFTEXT000023174854&dateTexte=&categorieLien=id
[65] http://publications.elia.be/upload/UG_upload/5SQMH9Z4FF.pdf
[66] http://www.gesetze-im-internet.de/bundesrecht/reskv/gesamt.pdf
[67] Unlike in the UK, no penalties are foreseen if an operator fails to generate when requested to do so. Operators of contracted reserve power could be contractually liable in case they fail to generate when requested to do so.
[68] http://www.bmwi.de/BMWi/Redaktion/PDF/G/gruenbuch-gesamt,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf
[69] http://www.bloomberg.com/news/articles/2015-01-20/germany-s-eon-facing-off-with-merkel-over-capacity-market
[70] http://www.icis.com/resources/news/2014/09/25/9823638/capacity-market-not-an-option-for-austrian-thermal-electricity-plants/
[71] http://www.sviluppoeconomico.gov.it/images/stories/normativa/decreto_approvazione_capacity_payment.pdf
[72] http://linklaters.com/pdfs/mkt/london/6883_LIN_Capacity_Markets_Global_Web_Spreads_Final_1.pdf

AEEGSI recognizes the importance of long-term price signals in order to ensure security of supply[73], and has introduced reliability options. The Italian TSO carries out adequacy assessments for the whole of Italy and for each zone.

IV.B.8. Country cases - Network codes

This part of the report illustrates specific country cases and the disparity of approaches to storage.

UK

In its version of 22nd January 2015, the UK Grid Code, based on the Electricity Act 1989[74], calculates pumped storage units as demand in the national demand of electricity.[75] The Code also defines Pumped Storage Generator as an entity that owns and/or operates any Pumped Storage Plant. It recognises pumped storage units as an important factor in balancing.

Austria

The Austrian Power Grid (APG) used the term load to comprise the consumption in the APG control area as a whole, including underlying public grids, grid losses and the consumption of pumped storage power plants. Load is consequently the electric power which has to be covered by power plant feed-ins or imports. As of 1st January 2015, to keep consistency with the data published according to Commission Regulation No 543/2013[76], the consumption of pumped storage power plants is no longer considered in the calculation of the term load.[77]

Italy

The Italian Grid Code[78] does not contain any definition of electricity storage. However, regarding statistical data that needs to be provided to TERNA (the Italian transmission system operator), storage is regarded as a generator. Storage is being defined as working reserves (thousands of m3) at that point in time in the tank system, without natural supplies and losses and gross electrical energy reserves of energy that would be produced by the hydroelectric plants concerned with storage, via full use of available water.

France

The System Service Rules of RTE (the French transmission system operator), define storage as a withdrawal unit, according to article L. 321-11 of the energy code.

Germany

[73] http://www.eurelectric.org/media/169068/a_reference_model_for_european_capacity_markets-2015-030-0145-01-e.pdf
[74] http://www.legislation.gov.uk/ukpga/1989/29/contents
[75] http://www2.nationalgrid.com/uk/industry-information/electricity-codes/grid-code/the-grid-code/
[76] 14th June 2013, on submission and publication of data in electricity markets and amending Annex I to Regulation (EC) No 714/2009
[77] https://www.apg.at/en/market/load/load-forecast
[78] http://www.terna.it/default/home_en/electric_system/grid_code.aspx

In Germany storage of electricity is mentioned in the Law on electricity and Gas Supply. The law mentions electricity storage in a way regarding security of supply. The Law states that the storage facilities are obliged to adjust the power or supply.

The Law states that in case the security of electricity supply is at risk or disturbed, the transmission system operators are obliged to eliminate the threat or interference by adopting network-related measures, in particular by power circuits, and market measures, such as balancing energy, management of bottlenecks and mobilization of additional reserves. In the mentioned cases, the providers of electrical energy storage are obliged to adjust the load or supply of the installations request of the TSO's, against appropriate remuneration.

Furthermore, the Law implies other regulations and obligations on storage facilities regarding the life-span and operation, but all from a perspective of security of supply of electrical energy[79]. EEG regulations does not cover storage/balancing requirements for the system.

[79] http://www.gesetze-im-internet.de/enwg_2005/BJNR197010005.html

V. CONCLUSIONS

As highlighted in the past and present analysis of this report, EU energy policy is mostly based on characteristics of existing generation assets (fossil fuel, nuclear and hydro), their ramping dynamics and start-up costs. So, far, flexibility has been provided from the generation supply side, and not demand side. It has been agreed by national regulators that the electricity grid supporting system flexibility should be designed up to the highest demand (peak demand) on the grid. The energy efficiency Directive leaves room for interpretation, where storage is envisaged as a demand tool.

Some elements of flexibility are already being incorporated in EU legislation and network codes (0 to 15 seconds to give time for primary reserve to come) as in system frequency regulation. However, the trend towards flexibility will be broader and larger, in order to allow transactions to take place in the energy market between generators, retailers and new actors like aggregators market (See section on "Business models") and to allow the integration of storage.

Storage is regarded as essential in order to balance supply and demand. Dynamic behaviour of storage will increasingly move in the direction of quick and powerful response to the dynamic needs of the grid because of the increasing participation of RES generators. Storage should be integrated at different levels of the electricity system, for example at transmission level as frequency control and at distribution level as voltage control or capacity support. Measures taken by the TSOs related to load scheduling and system stability are operational measures, which contribute indirectly to flexibility.

V.A. Ownership of storage

Ownership of storage facilities has to be assessed in relation to flexibility requirements of the system over the short, mid and long term. For this reason, the regulatory framework of storage needs to provide clear rules and responsibilities concerning the technical modalities and legal (ownership) status of energy storage facilities. It would have to enable storage facilities to integrate into both systems and markets. For example, it should guarantee a level playing field with other sources of generation, exploit its flexibility in supplying the grid, stabilise the quality and supplies for RES generation. For this reason, the regulatory framework should be technology neutral, in order to allow fair competition between different technological solutions. Electricity storage facilities should be accessible whatever the size and location of the storage on the electricity network.

As shown above, there is no EU legislation specifying definition of storage facilities and TSOs treat pumped hydro storage as they see it fit to their local circumstances. The different approaches across national markets may create distortions which have an impact on access and related costs for pump storage energy in neighbouring markets.

Commission Regulation No 543/2013 on submission and publication of data in electricity markets excluded storage from the definition of 'total load' (load includes losses without power used for energy storage, meaning it is a load equal to generation and any imports deducting any exports and power used for energy storage), and therefore implicating that storage of electricity is not a mere generation unit like other production facilities. This already implies that electricity storage is regarded as a 'different' factor in the electricity market.

According to **EU legislation**, TSOs are required to act and manage the system, while taking into account the benefits of demand side response. These responsibilities were developed further in Directive 2009/72/EC, concerning common rules for the internal market electricity, under Article 12, where transmission system operators are not only responsible for the management of energy flows, but also for ensuring the availability of all necessary ancillary services, including those provided by demand response.

As such, new legislation related to **flexibility** will have to be developed along the integration of RES assets, decentralised generation, and demand response, based on the assessment of flexibility needs at national and regional levels.

These roadmaps should be considered notwithstanding the potential for Power-to-heat and Power-to-gas to efficiently optimize flexibility of integrated energy networks in electricity, gas, heating and cooling[80].

V.B. Flexibility definition

The International Energy Agency (IEA) defines flexibility in the context of the electricity system, as the "Extent to which a power system can adjust the balance of electricity production and consumption in response to variability, expected or otherwise"[81]. According to the IEA, it can be measured relative to supply or demand.

In a Eurelectric Paper[82], the European association of electric utilities, puts together some interesting elements surrounding the definition of flexibility. Eurelectric differentiates flexibility on the demand side and flexibility used by system operators. However, with the development of capacity markets, more options are opened for demand response to act in capacity markets, under the coordination of the TSO. Therefore, this distinction may need to be adapted.

As a general policy objective, flexibility should be made available under the general condition that it tends to minimise balancing cost on the generation market, reduces grid congestions and mitigate grid reinforcement costs.

V.C. Future business models

A comprehensive simulation on the value of storage has been done including modelling of two scenarios, a reference scenario and a CO_2 scenario including much more ambiguous deployment of renewable generation.

Two types of storage have been considered, pump storage and battery storage. The key output of the simulation is comparing the value of storage compared to the potential revenue generation.

[80] Insight-E, "Synergies in the integration of energy networks for electricity, gas, heating and cooling", RREB1, June 2014
[81] "Renewables Grid Integration and Variability", IEA, 2014
[82] "Flexibility and Aggregation Requirements for their interaction in the market", Eurelectric, January 2014

Energy storage can potentially provide a wide range of services including energy arbitrage, peak shaving and system services. It is clear that bundling of services will increase the value of storage but also increase the complexity and the need for new business models and reformed regulation.

The conditions in various countries are very different and the main objective of the study is to analyse how different conditions will lead to better or worse case for storage. The study has been limited to studying the value of energy arbitrage to keep the modelling at reasonable levels. If for instance the value of peak shaving is to be considered the highest value is typically in deferment of grid infrastructure investments and this is a very complex analysis.

The study looks at the value of centralized storage.

V.C.1. Methodology

Within this study the wholesale market prices are derived for two specific years (2030 and 2050) using a model based approach. Two scenarios of power plant portfolios are analysed for each year and these scenarios are developed using outputs from the EUSTEM model. A power plant portfolio is constructed for each Member State for each scenario (Reference and Mitigation) and each year (2030 and 2050). In all, approximately 3,000 individual thermal power plants are included in the model. Power plant capacities, efficiencies and fuel types are based on outputs from the EUSTEM model. The model will aim to minimise the overall generation cost to meet demand subject to generator technical characteristics. The resulting market price is defined as the marginal price at MS level (note that this is often called the shadow price of electricity) and does not include any extra revenues from potential balancing, reserve or capacity markets or costs such as grid infrastructure cost, capital costs or taxes. These extra revenues or costs are not considered in this study.

Results of the study are shown for the years 2030 and 2050.

Table V-I: Summary of wholesale prices from modelling results for 2030

		Pumped Storage		Pumped Storage		Pumped Storage		Pumped Storage	
		Austria		France		Germany		Italy	
Property	**Units**	**2030 Reference**	**2030 CO_2 Scenario**	**2030 Reference**	**2030 CO_2 Scenario**	**2030 Reference**	**2030 CO_2 Scenario**	**2030 Reference**	**2030 CO_2 Scenario**
Wholesale Price	$/MWh	90.72	92.13	85.62	56.85	84.23	86.04	95.21	96.63
Generation	GWh	465	728	408	1583	4922	9482	6053	5360
Hours of Operation	hrs	681	764	291	1250	1309	1845	2347	2140
Capacity Factor	%	2	3	3	10	8	16	9	8
Energy Cost	$000	42834	71439	37678	46420	442723	815946	616567	559886
Net Revenue	$000	3523	4635	2261	34286	12823	120700	7756	6343
Max Capacity	MW	303	303	362	362	303	303	306	306
Installed Capacity	MW	3030	3030	1810	1810	6666	6666	7650	7650

Table V-II: Summary of wholesale prices from modelling results for 2050

		Pumped Storage		Batteries		Pumped Storage		Batteries		Pumped Storage		Batteries		Pumped Storage		Batteries	
		Austria				France				Germany				Italy			
Property	**Units**	**2050 Reference**	**2050 CO_2 Scenario**	**2050 Reference**	**2050 CO_2 Scenario**	**2050 Reference**	**2050 CO_2 Scenario**	**2050 Reference**	**2050 CO_2 Scenario**	**2050 Reference**	**2050 CO_2 Scenario**	**2050 Reference**	**2050 CO_2 Scenario**	**2050 Reference**	**2050 CO_2 Scenario**	**2050 Reference**	**2050 CO_2 Scenario**
Wholesale Price	$/MWh	102.36	94.56	102.36	94.56	98.91	20.61	98.91	20.61	96.30	103.46	103.60	103.60	102.63	89.33	102.63	89.33
Annual Generation	GWh	593	696	0	2377	671	3336	0	24684	5098	9063	0	48065	7017	11589	0	57610
Hours of Operation	hrs	636	868	0	2154	436	1585	0	2977	1214	1615	0	3132	1520	1662	0	4277
Capacity Factor	%	2	3	0	19	4	10	0	10	9	16	0	14	11	17	0	14
Energy Cost	$000	64123	27231	0	150773	73404	1009	0	410277	531889	302315	0	2750066	783213	285471	0	2989015
Net Revenue	$000	4573	39018	0	107769	4007	7385	0	116426	14055	597315	0	2500813	19862	777929	0	2385365
Max Capacity	MW	303	303	0	1400	362	756	0	29078	303	303	0	39600	306	306	0	45600
Installed Capacity	MW	3030	3030	0	1400	1810	3780	0	29078	6666	6666	0	39600	7650	7650	0	45600

V.C.2. Conclusions

The key learnings from the study are in concentrated form:

- The simulations verify findings in other studies that multiple benefits are required to justify battery storage.
- There is a clear correlation between degree of RES implementation and the value of storage. This is illustrated by the difference in feasibility of storage in the reference scenarios and the CO_2 scenario.
- There is with current estimations of battery prices no business case for battery storage 2030 but in 2050 in selected markets.
- There is a large variation between the selected countries Austria, France, Germany and Italy. The main reason is the significant difference in production mix and infrastructure.
- Further studies including how multiple benefits could be used would be justified but require significantly larger efforts. It is likely that such studies would reveal even larger national differences.

V.D. Recommendations

Flexibility needs in the wholesale market under the short term horizon

Flexibility is brought forward in the market, under relatively short time frames, but, these conditions need to be clearly defined.

Table V-III: EU policy on flexibility in wholesale market operations – Real Time (two days to real time)

Flexibility requirements	Examples of Flexibility measures	EU policy item on flexibility	Value creation
Manage RES variability	Generation disconnection	How storage assets can play a role?	Lower the distribution risk of imbalance revenues
Allow adjustments to load forecasts	Lower threshold to put a bid on the balancing market.	RES balancing obligation, as a balancing services provider?	Reduction of system services costs
Allow an increasing number of companies (EV cars' fleets; heat pumps) to participate in the market	Define metering requirements.	Curtailment of generation plants on the DSO grid	Reduction of system service costs through investments' deferrals
	So that smaller flexible sites can participate in the balancing market	Foreign participation in balancing market	
		DSO flexibility[83] [84]to ensure regional forecast of supply and demand	

Flexibility needs under the mid to long-term horizon

Ensure that **flexibility needs can be anticipated**; Flexibility needs will be derived from the capacity of market players to anticipate load adjustments and RES feed in forecasts.

Ensure a level playing field to competition. Flexibility also depends on the **liquidity of the market** and would require a certain level of competition between the main players i.e. arbitrage between day-ahead and intraday markets, between peak and base load prices

[83] Ifri Editorial: "The EU Electricity Policy Outlook for the Smart Grid Roll-Out", Aurélie Faure-Schuyer, October 2014
[84] Ifri Editorial: "Demand Response in Europe's Electricity Sector: market barriers and outstanding issues", Cherrelle Eid, April 2015

Concluding remarks on the role of flexibility and storage

Due to the fact that RES electricity generators are continuously playing a more important in the current electricity markets, defining electricity storage on a uniform and union-wide manner is an important step in EU legislative framework elaboration, preventing different approaches by the national TSO's (or DSO's).

Based on the analysis in section on "Business models", storage facilities should be generally understood as a semi-regulated activity, with the primary goals to serve the purpose of ensuring flexibility in the system while securing security of supply.

Given the "semi-regulated" nature of storage, storage facilities should be owned by a separate body, a 'storage system operator', in line with the unbundling rules of the Third Package[85].

The Third Package also sets a number of other rules that are to be applied to storage facilities. The most important among them are rules regarding data communication, transparency and cooperation. These rules should apply to storage operators when supplying energy to TSOs or DSOs.

Further extensive research needs to be done on finalizing and establishing the needs and obligations of storage facilities in order to fulfil the foreseen role of storage facilities in a European electricity market, as well as securing communication between the 'storage system operators' and the TSOs and DSOs.

[85] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0055:0093:EN:PDF, http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF

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APPENDIX A – EUSTEM MODEL

Table E1: Regional share in EU-28 + Switzerland and Norway (2014)

Regions	Electricity demand (TWh)	Installed Capacity (GW)
CROSSTEM (Austria, France, Germany, Italy, Switzerland)	47%	45%
Austria(AT)	*2%*	2%
France (FR)	*16%*	12%
Germany (DE)	*18%*	17%
Italy (IT)	*9%*	12%
Switzerland (CH)	*2%*	2%
EAST (Hungary, Poland, Czech Republic, Slovakia, Slovenia)	9%	7%
SPAPO (Spain, Portugal)	10%	12%
UKIRE (UK, Ireland)	11%	9%
NORDIC (Norway, Sweden, Finland, Denmark)	12%	9%
BNL (Belgium, Netherland, Luxembourg)	5%	4%
GRE (Greece)	2%	2%
Total Share of EU-28 + Switzerland & Norway	***96%***	***90%***

Table A2: Electricity generation technology data

Technology Description	Vintage Year	Life time (year)	Eff (%)	AF (%)	Capital Cost (CHF/kW)	FOM Cost (CHF/kW/year)	VOM Cost (CHF/GJ)	Lead time (year)
Hydro+ (River)	2015	80	80%	63%	6'560	18.2	1.67	3
Hydro+ (Dam)	2015	80	80%	27%	10'000	9.7	1.84	3
	2030	80	80%	27%	8'000	9.7	1.84	3
Nuclear^ : Gen2 (LWR)	2010	50	32%	80%	4'250	22.5	3.25	6
Gen3 (EPR)	2030	60	35%	80%	4'250	11.6	1.92	6
Gen4 (FBR)	2050	40	40%	80%	4'750	55.1	0.18	6
Coal: SCPC*	2010	30	43%	80%	2'350	40.3	0.69	3
	2030	35	50%	87%	2'150	45.1	0.79	3

Technology Description	Vintage Year	Life time (year)	Eff (%)	AF (%)	Capital Cost (CHF/kW)	FOM Cost (CHF/kW/year)	VOM Cost (CHF/GJ)	Lead time (year)
	2050	35	54%	87%	2'050	45.1	0.79	3
Coal: SCPC with CCS	2030	35	43%	87%	3'200	69.3	0.92	3
	2050	35	49%	87%	2'900	69.3	0.92	3
Lignite$: SCPC	2010	40	40%	86%	2'450	52.0	0.69	3
	2030	40	43%	86%	2'241	58.2	0.79	3
	2050	40	49%	86%	2'137	58.2	0.79	3
Lignite: SCPC with CCS	2030	40	33%	86%	4'480	95.0	0.92	3
	2050	40	41%	86%	4'060	95.0	0.92	3
Natural Gas: GTCC# Base load	2010	25	58%	82%	1'150	7.8	6.72	3
	2030	25	63%	82%	1'050	7.8	6.72	3
	2050	25	65%	82%	1'050	7.8	6.72	3
Natural Gas: GTCC with CCS	2030	25	56%	82%	1'700	15.6	13.44	3
	2050	25	61%	82%	1'500	15.6	13.44	3
Solar: PV	2010	40	100 %	11%	6'500	5	1	0
	2030	40	100 %	11%	2'850	5	1	0
	2050	35	100 %	11%	1'950	5	1	0
Wind+: Onshore	2010	20	100 %	14%	2'150	44	14	0
	2030	20	100 %	14%	1'750	28	9	0
	2050	20	100 %	14%	1'750	28	9	0
Wind: Offshoreβ	2010	20	100 %	44%	3'350	87	9	2
	2030	20	100 %	44%	2'350	58	6	2
	2050	30	100 %	48%	2'100	22	14	2
Geothermal	2020	30	100 %	80%	13'825	134	12	3
	2030	30	100 %	80%	6'650	87	29	3
Waste Incinerator	2010	30	40%	15%	8'924	422	1	3

Technology Description	Vintage Year	Life time (year)	Eff (%)	AF (%)	Capital Cost (CHF/kW)	FOM Cost (CHF/kW/year)	VOM Cost (CHF/GJ)	Lead time (year)
Pump hydro	2010	80	80%	27%	7'000	10	2	3
Tidal Power plant°	2010	25	100 %	30%	2'850	49	-	3
	2010	25	100 %	33%	6'449	65	2	3
Solar: CSP&	2030	25	100 %	33%	3'702	65	2	3
	2050	25	100 %	33%	3'295	65	2	3
Interconnector	2010	50	100 %	90%	434	1.2	0.4	0
CAES**	2010	30	50%	50%	1'200	36	-	3
	2030	30	55%	50%	900	27	-	3
	2050	30	60%	50%	600	18	-	3
Battery$$	2010	15	70%	50%	3'120	94	-	3
	2030	20	80%	50%	2'592	78	-	3
	2050	20	85%	50%	1'800	54	-	3

+ All renewable availability factors (AF) given in this table are for Switzerland. AF's varies across different regions, especially those for renewable technologies (not shown).
^ LWR – Light Water Reactor, EPR – European Pressurised Reactor, FBR – Fast Breeder Reactor
* SCPC - Supercritical pulverized coal
$ Lignite fired power plants are only available in Germany.
# GTCC - Gas turbine combined cycle – The data given is for base-load plants. For flexible gas plants (merit order), the same cost numbers have been used, but a 20% penalty is applied to efficiency and availability factor to account for interrupted operation.
β Technology available only for Germany, France, and Italy.
° Technology available only for Italy and France.
& Technology available only for Italy.** Compressed Air Energy Storage

$$ Flow Battery storage for wind turbines and large scale solar PV generation

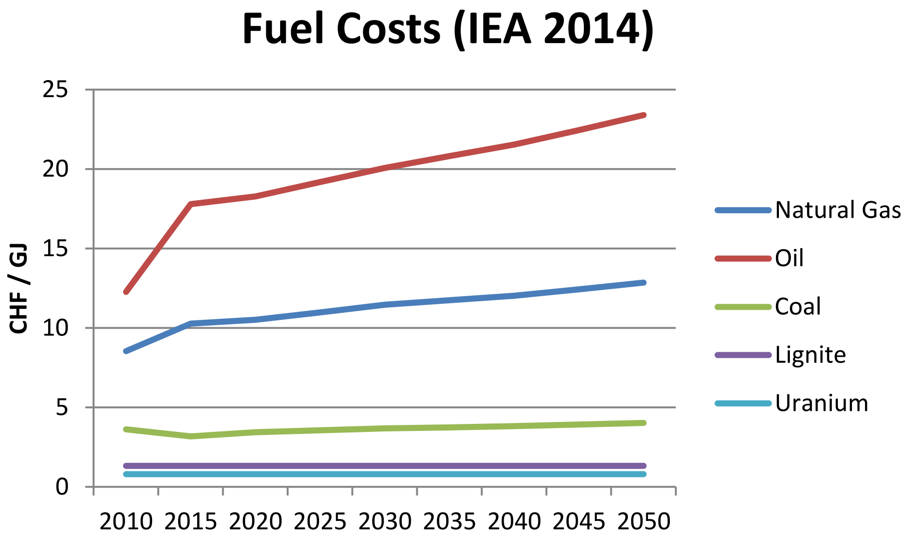

Figure A1: Fuel Costs in EUSTEM

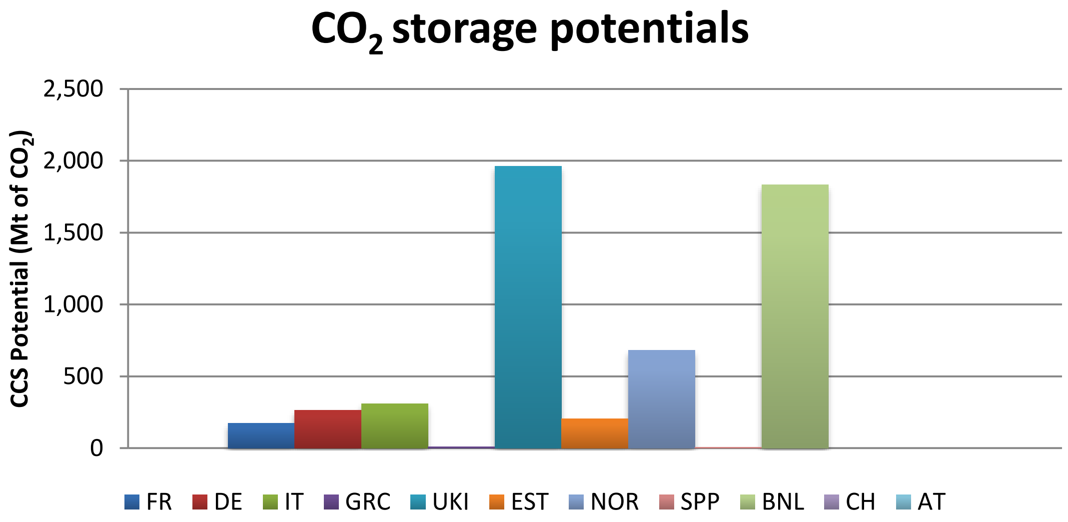

Figure A2: CCS storage potentials

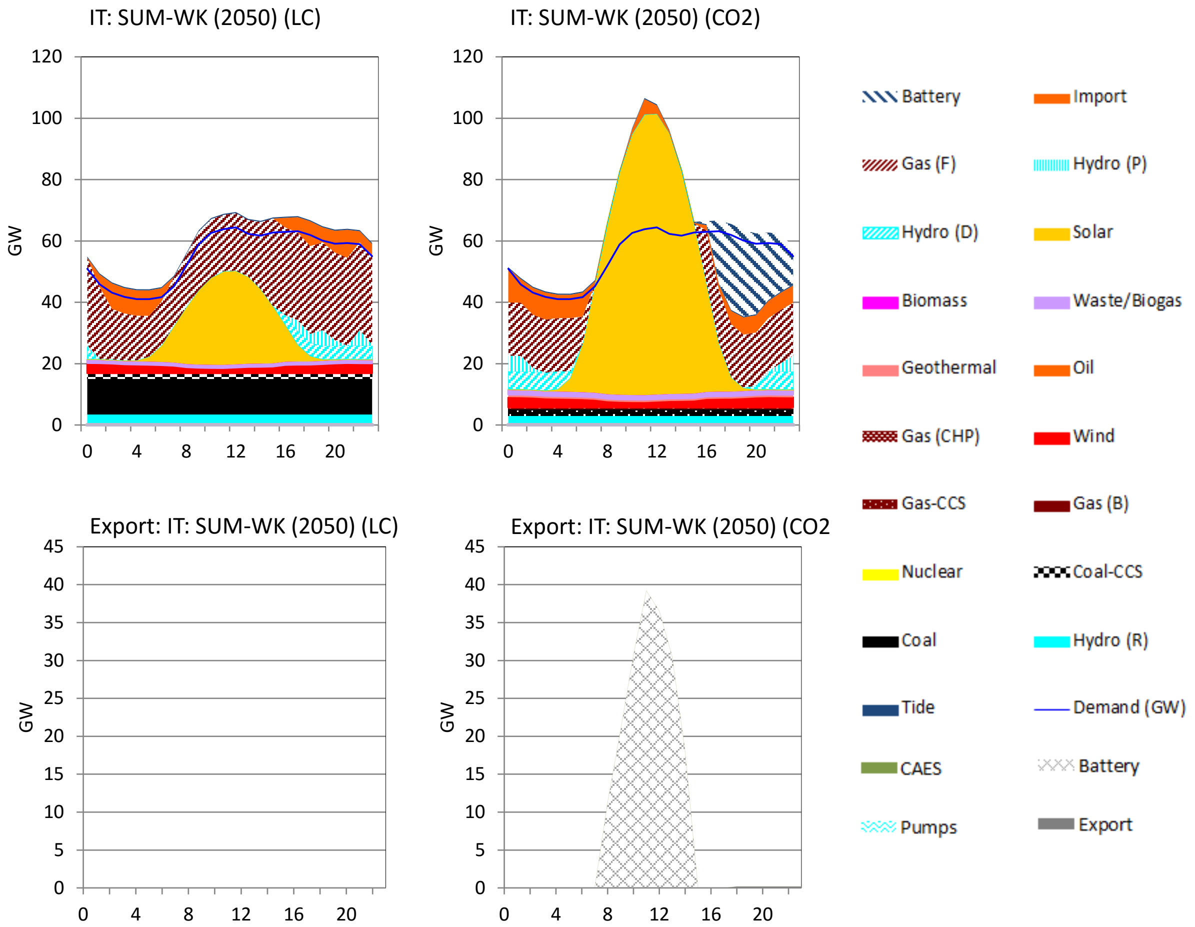

Figure A3: Italy load curve 2050 (Summer Weekday)

Appendix B – Case studies

Germany's case study – Grid fees exemptions

Traditionally, German PHS plants have not been charged for the transmission of pumping electricity.

Since January 2008, though, the regulator decided to charge grid fees for pumping electricity[86]. However, since 2009, new PHS plants will be exempt from all grid fees for 10 years (EnWG, 2009); an exemption period that was later extended to 20 years (GNeV, 2011).

Germany's case study – Participation to primary control reserve market

For instance, there is already an opportunity for a primary control reserve market in Germany, but the point is that you have to bid each week, which entails a huge long-term uncertainty, and impedes the deployment of storage solutions dedicated to this market.

France case study: PHS participation to the Frequency Reserve

In a multi-annual contract arrangement, French TSO (RTE) has secured a capacity reserve from different PHS, designed to provide 1500MW of capacity under the following time frame: 1000MW in less than 13 minutes with an additional 500MW in less than 30 minutes. This tertiary reserve capacity is dimensioned according to ENTSO-e's frequency reserve rules in a synchronous area based on a reference incident[87]. It cannot participate in the balancing market.

Under the French regulatory framework, each power plant is limited to a 7% participation to primary and secondary reserve, going up to 12% for hydro based systems.

Italy: unbundling rules interpretation

The Legislative Decree[88] implementing Directive 2009/28/EC on the promotion of renewable energy sources (RES) calls on Terna, the Transmission System Operator (TSO), to identify in its network development plan the reinforcements necessary to ensure that RES generation is fully dispatched. These plan can, according to the decree, include energy storage systems among them pumped hydro storage, that are awarded according to tendering procedures. The National Regulatory Authority (NRA) provides for the regulation and ensures that the return on investment for the construction and operation of the works properly takes into account the different storage technologies. The Italian legislative framework, accordingly, warrants a premium (above the cost of capital) for investments in storage. According to Legislative Decree 01.06.2011, Terna and the DSOs can build and operate movable storage systems (batteries). According to Terna's Network Development Plan, batteries for a minimum of 130 MW should be developed and would avoid procuring 410 GWh/year on the balancing market.

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[86] "Neu errichtete Anlagen zur Speicherung elektrischer Energie": § 118 Abs. 6 S. 1 EnWG
[87] The reference incident shall be sized taking into account at least the loss of the biggest power generation / consumption unit or the loss of a line section, bus bar or HVDC interconnector that may cause the biggest imbalance with an N-1 failure.
[88] Legislative Decree 03.03.2011 N.28

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List of Abbreviations

APC	Active Power Control
BES	Battery Energy Storage
CAES	Compressed Air Energy Storage
CAPEX	Capital Expenditure
CCG	Combined Cycle Gas
CCS	Carbon Capture and Storage/Sequestration
CESA	California Energy Storage Alliance
CHP	Combined Heat and Power
CSP	Curtailment Service Providers
DLC	Double-Layer Capacitors
DR	Demand Response
DSM	Demand Side Management
DSO	Distribution Network Operator
EASE	European Association for Storage of Energy
Ecoprog	European Market for Pumped Storage Power Plants
EERA	European Energy Research Alliance
EES	Electric Energy Storage
ENTSO-E	European Network for Transmission System Operators for Electricity
EUSTEM	European Swiss TIMES Electricity Model
EV	Electric Vehicle
HC	Hard Coal
ICE	Internal Combustion Engines
IEA	International Energy Agency
IEC	International Electrotechnical Commission
ISO	Independent System Operator
ITO	Independent Transmission Operator
LIGN	Lignite
MS	Member State
NPP	Nuclear Power Plant
OCGT	Open Cycle Gas Turbines

OPEX	Operating Expenditure
OU	Ownership Unbundling
PHES	Pumped Hydro Energy Storage
PHS	Pumped Hydro Storage
PUN	prezzo unico nazionale or average national power price (for Italy)
RAB	Regulated Assets Base
RES	Renewable Energy Sources
SMES	Superconducting Magnetic Energy Storage
T&D	transmission and distribution
TSO	Transmission System Operator
UKPN	UK Power Networks
V2G	Vehicle-to-grid
VRES	Variable Renewable Energy Sources
WACC	Weighted average costs of capital

GLOSSARY OF TERMS

Aggregator	An "aggregator" is a broker that acts on behalf of a group or groups of customers. Typically, an aggregator will set up arrangements with members of groups such as homeowner associations, affinity groups (religious, cultural, regional, fraternal, etc.) and seek rate offers from suppliers for these "bundled" groups of customers. Customers typically do not pay for the aggregator's services, and are not contractually required to accept the supplier offers that the aggregator finds. The possible advantage is that the aggregator can offer a larger customer pool to the supplier, and may be able to get more competitive offers as a result.
Arbitrage	Arbitrage is the simultaneous purchase and sale of an asset in order to profit from a difference in the price. It is a trade that profits by exploiting price differences of identical or similar electricity sources, on different markets or in different forms.
Black start	A black start is the process of restoring an electric power station or a part of an electric grid to operation without relying on the external transmission network. Normally, the electric power used within the plant is provided from the station's own generators.
Dispatchable	Dispatchable generation refers to sources of electricity that can be dispatched at the request of power grid operators or of the plant owner; that is, generating plants that can be turned on or off, or can adjust their power output accordingly to an order.
Flexibility	Flexibility is the ability of a power system to maintain continuous service in the face of rapid and large swings in supply or demand
Reactive power	Reactive power is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage.
Reserve Margin, Reserve Capacity	A measure of available capacity over and above the capacity needed to meet normal peak demand levels. Reserve margin and reserve capacity are synonymous. For a producer of energy, it refers to the capacity of a producer to generate more energy than the system normally requires. For a transmission company, it refers to the capacity of the transmission infrastructure to handle additional energy transport if demand levels rise beyond expected peak levels. Regulatory bodies usually require producers and transmission facilities to maintain a constant reserve margin of 10-20% of normal capacity as insurance against breakdowns in part of the system or sudden increases in energy demand.