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A review at the role of storage in energy systems with a focus on Power to Gas and long-term storage

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ABSTRACT

A review of more than 60 studies (plus more than 65 studies on P2G) on power and energy models based on simulation and optimization was done. Based on these, for power systems with up to 95% renewables, the electricity storage size is found to be below 1.5% of the annual demand (in energy terms). While for 100% renewables energy systems (power, heat, mobility), it can remain below 6% of the annual energy demand. Combination of sectors and diverting the electricity to another sector can play a large role in reducing the storage size. From the potential alternatives to satisfy this demand, pumped hydro storage (PHS) global potential is not enough and new technologies with a higher energy density are needed. Hydrogen, with more than 250 times the energy density of PHS is a potential option to satisfy the storage need. However, changes needed in infrastructure to deal with high hydrogen content and the suitability of salt caverns for its storage can pose limitations for this technology. Power to Gas (P2G) arises as possible alternative overcoming both the facilities and the energy density issues. The global storage requirement would represent only 2% of the global annual natural gas production or 10% of the gas storage facilities (in energy equivalent). The more options considered to deal with intermittent sources, the lower the storage requirement will be. Therefore, future studies aiming to quantify storage needs should focus on the entire energy system including technology vectors (e.g. Power to Heat, Liquid, Gas, Chemicals) to avoid overestimating the amount of storage needed.

1. Introduction

In the last 120 years, global temperature has increased by 0.8 °C [1]. The cause has been mainly anthropogenic emissions [2]. If the same trend continues, the temperature increase could be 6.5–8 °C by 2100 [2]. The power sector alone represents around 40% of the energy related emissions [3] and 25% of the total GHG emissions [4] with an average global footprint of 520 gCO_2/kWh [3]. In the heating sector, around 65% of the energy is used for space and water heating and the energy consumption in buildings can translate to around one quarter of the equivalent electricity emissions [4]. Therefore, there is a need to take corrective actions to curve this trend and decrease the potential consequences. The solution is seen as a combination of energy efficiency, biomass use, carbon capture and storage (CCS) and the use of renewable energy sources (RES). In the last category, there has been a tremendous expansion of wind and solar. In the last 10 years, wind has had an average growth of 22%/year, while solar has 46%. Nevertheless, at present they only represent around 3.6% and 1.1% respectively of the global electricity production (24,100 TWh) [5]. In the future, these two technologies are expected to represent most of the contribution in RES.

A disadvantage of variable RES (VRE) is their fluctuations in time and space with an associated uncertainty (especially for wind) and lower capacity factors in comparison to conventional technologies.[1] There are different flexibility measures to respond to these fluctuations and meet the demand at all times, where storage is one of them, specifically to deal with their temporal component. Storage can provide both upward and downward flexibility, storing energy either when there is generation surplus or lower demand and discharging in the opposite case. Depending on the time scale (miliseconds up to months), there are different roles that storage can play [6,7].

Currently, there are no large scale alternatives for seasonal storage of electricity. The closest one is pumped hydro storage, which is limited to certain geographical locations, has a high water footprint and is usually used for storage times of less than one week [8–10]. A developing technology that arises as alternative is Power to Gas (P2G) [11,12]. This comprises power conversion to hydrogen through electrolysis with the possibility of further combining it with CO_2 to

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[1] Typical values for capacity factors are 0.1–0.2 for solar and 0.2–0.4 for wind, while a nuclear power plant is around 0.85.

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produce methane. The technology is currently at its early stages and has a high specific cost and low efficiency as limitations. However, it is expected that to achieve 100% RES scenarios (with a large contribution from VRE) P2G will be needed [13]. This option complements the common application of storage for short-term applications and balancing of VRE fluctuations with a long term function. Similar as Power to Liquid, it establishes the link between the power sector and others (i.e. heating and mobility) facilitating the decarbonization of the other sectors.

This study has two main purposes: 1. Review existing literature and analyze storage needs and performance from a systems perspective, looking at the entire energy systems (power, heat and mobility) since the more options are available, the less dependence there will be on a single technology and 2. Compare the storage need for a 100% RES energy system with the potential for the technologies that can perform this function, with special attention to P2G due its high energy density and possibility for seasonal storage. Such review has not been found in the literature, where the reviews have been focused on the technology (e.g. [14] for storage in general, [8] for PHS and [11] for P2G), value (e.g. [15]) and applications (e.g. [16]). The advantage of a systems perspective is that it allows understanding how much storage is really needed without being carried away by the specificities of the system. Some studies [17–19] only focus on a couple of flexibility options and might overestimate the amount of storage needed, since the more alternatives are included, the less dependence there will be on the need for expansion in a single one of them. This review includes the quantification of the storage need, based on different studies with a RES penetration from 20% to 100% to establish a relation between RES and storage size and also looking at the difference between power systems only and energy systems.

This study is organized in the following manner. Since the objectives for each section are different, the type of studies considered is slightly different for each section. Thus, the first point explained (Section 2) is the general classification of the studies, as well as the details of which ones are included in each of the sections. Section 3 discusses storage as one of the possible sources of flexibility. Section 4 compares storage with those other flexibility options, by going through different studies and establishing the trade-offs in size and cost with respect to those other technologies. Since the implementation of a technology in fully competitive markets is usually dependent on its profitability and economics, Section 5 is dedicated to the cost impact of storage, including the cost savings achieved with storage, cost incurred for reaching a high VRE penetration without storage and emergence of storage in cost optimal configurations. Next (Section 6), a broad question is aimed to be answered, "how much storage is needed and how to satisfy this need". For this, a split is made between storage demand based on studies looking at 100% RES systems and studies that look at transition scenarios (i.e. 30–90%). The reason for this split is to evaluate if there is a marked difference both, since it is expected that 100% RES systems will demand a larger contribution from storage, given their larger contribution from VRE. Since it is proposed that P2G can satisfy this need, the total storage requirement is put in perspective by comparing it with the energy demand from various (gas consuming) sectors, but also with the technical potential that could be achieved by other large scale technologies. Finally (Section 7), P2G is discussed, looking at the various value chains that can arise, reviewing the work that has been done in assessing its role in the future, the competition with other alternatives and how the learning curve for the technology can affect such role, while paying more attention to the studies on energy systems for being the focus of the present review.

It is also important to highlight the boundaries for this study and the elements that are not included. A review of the technologies available for energy storage and the comparison of its technical characteristics (including fundamentals, cost, efficiency, services provided by each technology) is not included, since there are other reviews covering this [14,16,20–22]. The value of storage depending on the application and the comparison with the revenues is briefly mentioned in some sections, but it is not the core of the study. For these, refer to [6,7,15,23–29]. This also includes the aggregation of services and different revenue streams to make the storage economically profitable [30] or the split of storage use among different markets (e.g. wholesale, balancing, reserves) [31–35]. Making storage economically attractive based purely on price arbitrage [36–38] is difficult and another approach is to change the market design and current guidelines considering both storage and VRE increase [39,40], which is not part of this review either. Therefore, the main contribution of this publication is in the space of the role of storage from a systems perspective and the dynamics with the rest of the elements is such system, quantifying the storage size in energy terms and understanding the influence of the system configuration in its size. This study aims to have one level of abstraction higher to identify if there is a trend, regardless of the technology used and services provided.

The range of papers reviewed include power and energy models, optimization (usually based on cost), simulation, operational and investment planning resulting in more than 60 studies. The reason to consider power models as well, in spite of the need to focus on the entire energy system, is that these are usually complementary to the energy models. Power models focus on the short term dynamics and operational constraints (e.g. hourly resolution for a year) and can have more detail on the transmission network (to deal with the spatial balancing), while energy models usually look at the longer term (e.g. 50 years) and simplify the time resolution (using representative time slices for a year and aggregating them or using parametric equations to represent the variability of RES). Therefore, conclusions on the role of storage require insight from both types of models due to their complementary nature. Being P2G a potential storage technology, the input from power models is valuable to look at the hourly change of inventory and enabling to capture better its use. The criteria for selection are different depending on the objective of each section. Therefore, each section contains a brief explanation of the criteria used for selection of the studies.

2. Studies overview and classification

The studies selected for the review aim to go beyond the classical operational power models. To be included in this review, at least one of the boundaries or an extra element needs to be considered. This refers specifically to: 1. Boundary between operational (short-term) and investment (long-term) component (meaning optimization of both components, e.g. [41–43]); 2. Boundary beyond the power sector (including heat and mobility, e.g. [44,45]); 3. Combination of multiple flexibility options and insight on trade-offs between them [46–48]; 4. Done by a recognized (inter)national organization with a systematic approach (e.g. [7,49]); 5. With P2G as one of the storage technologies (all studies in Section 6 and Appendix G). The range of studies can be classified in:

- Only trade-offs between flexibility options [18,50,51]. These only look at the interaction between variables, with focus on the power sector and without considering the cost impact. Reason to look into these is that they provide insight of the dynamics between storage and the other flexibility options.
- Optimization power models [43,52,53]. These focus on power and optimize the energy mix based on minimum cost.

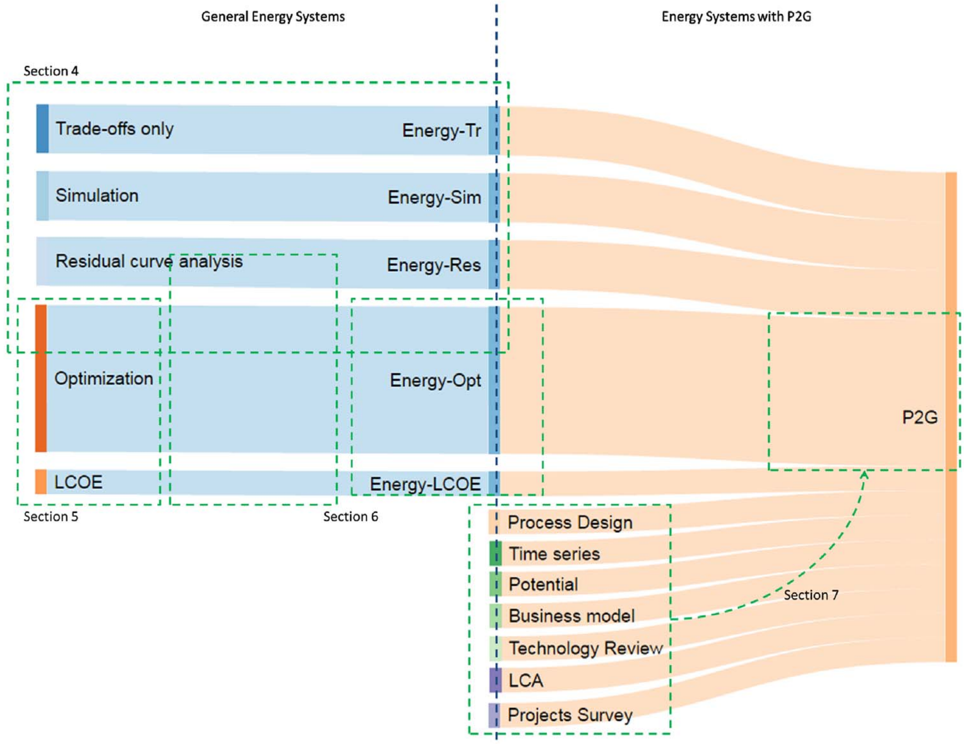

Fig. 1. Overview of studies included in this review and areas covered by each section.

- Optimization energy models [44,54,55]. These include the wider energy system (also heat and mobility) and at the same time optimize the energy mix based on cost.
- Residual curve analysis [47,48]. These look at the power surplus in both net power (VRE production minus demand) amount and number of hours in a year as a function of RES penetration and variation of other measures in the system (e.g. flexible generation).
- Simulation [56] are the ones where the storage size might not be the (cost) optimal, but instead aim to assess the impact of different sizes and possible VRE integration with variable size.

The sub-categories for P2G will be explained in Section 7. However, these are also included in Fig. 1 that shows the range of studies covered as well as which ones are included in each section.

In Section 4, the ones looking at trade-offs and dynamics of the system are included, part of this is the optimization studies where the sensitivities usually allow developing understanding of how changes in the storage size can affect the rest of the system. In Section 5, the focus is on cost, therefore, mostly the ones looking at optimization are considered, since otherwise the storage cost reflected might too low or high resulting in misleading observations. Section 6, mostly focuses on optimization models to quantify the storage needs, but an exception is the stoRE project, which was included for its consistency, transparency and high (80%) penetration. The two blocks in Fig. 1 for Section 6 aim to represent the split between transition (30–90% RES) systems and fully renewable (100%) ones. In Section 7, first a broad view is taken, where all the studies related to P2G are mapped. This can be done since it is a relatively new technology (compared to for example Power to Hydrogen only through electrolysis) and such a task is not too cumbersome. After this, a more detailed analysis is given to the P2G studies that focus on cost optimization and energy modeling.

The focus of the studies included in each section has similarity with the expected transition in the energy system, starting from power only (Sections 3–5) to considering other sectors (Section 6) to looking at key enabling technologies for high RES scenarios (e.g. P2G in Section 7).

Throughout this study continuous references are made to the RES/VRE fraction (usually expressed as percentage). This fraction is the normalized RES/VRE contribution compared to the average demand. This is to avoid using absolute values and be able to compare among studies covering different systems. The demand can be only power or the entire energy demand (power, heat, mobility) depending on the scope of the study reviewed. Similarly, the use of electricity vs. energy storage depends on the scope of the model. This scope (in terms of sectors covered) for each study is highlighted in Tables 1–3.

3. Storage as a flexibility option

This section aims to first define flexibility in the context of energy security, identify the sources of flexibility in a power and energy system.

3.1. Defining flexibility

Flexibility is one of the terms used to refer to the reliability of an energy system to cope with risks, threats and adverse events that can jeopardize its capacity to satisfy the needs of the end users. Hence, it is related to energy security and ensuring the demand is satisfied at all times. Since the energy system is a complex system, the dynamics between components will change in time and the response to such threats can be different at different points in time. Reliability therefore encompasses concepts at different time scales with complementary concepts for security, these are shown in Fig. 2, followed by a brief explanation [57,58].

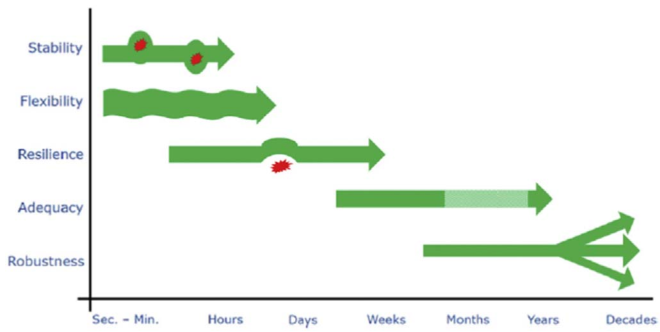

Fig. 2. Five key properties of a secure energy system (Taken from [58]).

switching) or a technology (e.g. nuclear). For this, the system should be physically (e.g. redundancy, sparing) and abstractly (market and regulations) ready.

- Adequacy: This covers making the investments in generation infrastructure in a timely manner to ensure undistorted competition and smooth price fluctuations due to imbalances.
- Robustness: Adapt the long-term evolution and trajectory of the system. The actors in the energy market should still be able to make decisions based on cost and prices and not based on economic or geo-political constraints.

Thus, flexibility is one of the key concerns with VRE, because of their unpredictability and sudden fluctuations in space and time that will continuously make necessary the adjustment of generation and

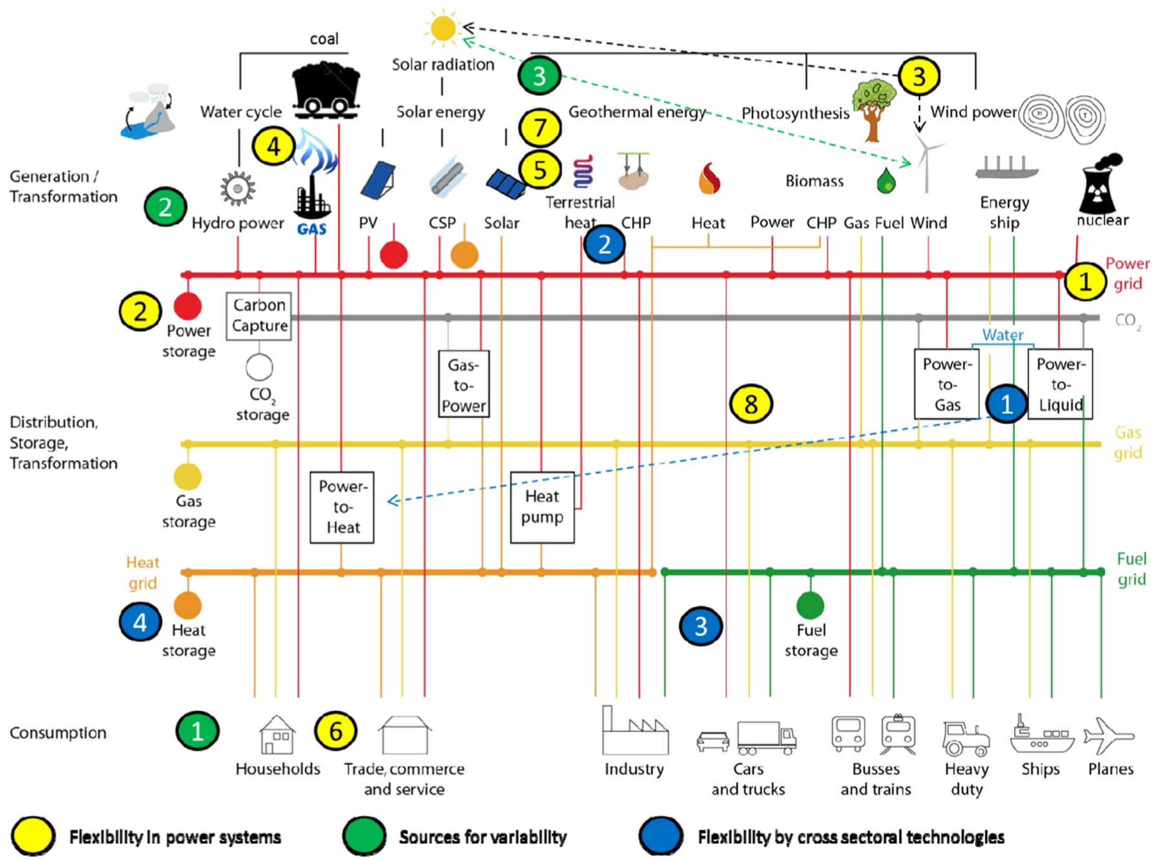

Fig. 3. Energy system with sources for variability and flexibility options (Adapted from [60]).

- Stability: Ability of a highly interconnected system to withstand sudden disturbances to the system (e.g. loss of a generator, loss of a transmission line) and maintain the system within its operational specifications. This refers to meeting voltage and frequency requirements for the power network, whereas the gas network is capable of handling better the fluctuations due to the gas storage facilities and packing of transmission lines providing additional volume.
- Flexibility: Cope with the short term uncertainty and deviations between forecasted and actual energy delivery. It refers to how fast can the system change the supply or demand curves to restore the balance.
- Resilience: Ability to use alternative modes of production as response to transient shocks like absence of a resource (e.g. fuel-

consumption to match their behavior, where its influence will only be more significant with higher contributions to the production. One way of defining these changes needed is in terms of ramp magnitude, ramp frequency and response time of the residual load (difference between renewable generation and demand) [59]. For storage, additional indicators are the storage and round-trip efficiencies.

3.2. Flexibility sources

In an energy system, there are different sources of variability that will affect the supply / demand balance, as well as different measures to cope with these unbalances. Furthermore, the mitigation measures can be in turn split into the ones that are applicable to the power network (which has the characteristic of no large contribution of storage and that changes propagate almost instantaneously throughout the system) and the flexibility provided by cross-sectoral technologies that allow making the match between power generation and use in another sector (i.e. use the larger heating/gas/mobility demand as possible sink for the surplus). The variability sources and flexibility options are shown in Fig. 3.

Before the widespread introduction of VRE, the main sources for variability were: (1) changes in demand (patterns) and (2) failures in generators or disruptions of the network (transmission and distribution lines). VRE would constitute an additional element (3) demanding flexibility with increasing importance as its fraction of the energy provided increases.

Looking specifically at the power system, some sources of flexibility are:

1. Network expansion. Deals with the spatial component in both generation (areas with different VRE patterns) and demand, besides enabling RES installation where they have the largest potential.
2. Storage. Deals with the temporal component of mismatch between generation and demand.
3. Wind and solar generation ratio. Generation patterns for wind and solar are complementary at the daily and seasonal level [61]. Optimal ratios have been assessed for Europe [18,19,62], US [63] and the world [61,64].
4. Flexible generation. This refers to the dynamic parameters (ramping rates, minimum stable generation, maximum throughput, minimum down time, start-up costs and part load efficiencies) for power plants. The wider the range for these variables, the easier they can adjust to fluctuations.
5. Excess of capacity. A larger VRE installed capacity can compensate for their low capacity factor and generate enough during low resource periods. The trade-off for security through this measure is the extra Capex and the larger possibility of curtailment.
6. Demand side measures [65].[2] Deals with the temporal component and can be in direct competition with storage. It enables shifting the peaks in the load aiming to make it more stable and match the generation curve. Costs are usually low (related to ICT [66]), but uncertain.
7. Curtailment. This option is usually attractive for low VRE penetration, when the number of hours with power surplus might be too small to justify the investment in any of the other options. A limitation is that it only provides negative reserve meaning [67] (i.e. only deal with electricity surplus).
8. System diversity [68]. The more technologies the better the system can cope with changes. An index to measure this diversity is the "Shannon Index" [69], which has been used to quantify the diversity of RES systems [53]. The diversity could also refer to geographical distribution of resources [68].

Another variable to consider is the balancing power. This works with the residual load. Any positive difference is either curtailed or stored (as heat or power) and any negative difference requires additional generation or withdrawal from the storage to satisfy the demand. Balancing power falls under the stability category with shorter time scales and fast responses needed. For these short-term fluctuations, part of the reserves is provided by synchronous generation, which is part of most conventional generation. With higher VRE, enough inertia in the system might not be available for instantaneous generation and might place additional constraints to the upper bound of VRE [68]. The reason to mention it and include it in the following section is that the same storage can be used for different time scales and the balancing need will, in some cases, affect the storage amount required.

Flexibility can also be provided by measures connecting the power system to other networks. A first set of choices in this category are the "Power-to-X" technologies. These are additional sources of flexibility that will only play a role when the system is expanded from power to energy. These include:

- Power to Heat (electric boilers, heat pumps) linking the surplus directly to a need and eliminating the inefficiency due to intermediate energy carriers (e.g. gas).
- Power to Liquid. This includes co-electrolysis of CO_2 and H_2O, hydrogenation of CO_2 and RWGS (Reverse Water Gas Shift) to produce Syngas and then fuel through Fischer Tropsch, methanol or DME. Another possible route is direct electro-reduction of CO_2 to methanol.
- Power to Chemicals. Once CO_2 and H_2O are converted to Syngas, a multitude of compounds can be produced including solvents, formic acid, alcohols, waxes, among others.
- Power to Gas. This can refer to the production of hydrogen through electrolysis or its subsequent conversion to methane with CO_2 from different sources (e.g. carbon capture, biogas, air). Variations can come from the electricity and CO_2 sources, end-carrier (H_2 or CH_4) and end-use.
- Power to Mobility. This makes the direct match between power surplus and demand in the mobility sector through electric cars specifically. This is more efficient, since it substitutes the internal combustion engine (efficiency of ~20%) or fuel cell (~50%) with an electric motor (~90%). Its limitations usually being infrastructure and large scale production by manufacturers.

A full review of the flexibility options with different technologies and studies done is available in [70].

4. Storage interaction with other flexibility options

The storage requirement for a system will depend on: the degree of variability introduced by VRE (i.e. fraction of energy being supplied by VRE), dynamics of the system and degree of response of the other flexibility measures. Even though it will depend on the conditions and configuration of the specific system, it can also be studied in a generic manner. Some pairs of flexibility options are analyzed and results from previous studies are highlighted to develop such understanding.

For this section, the criteria for selecting the studies were:

- Storage had to be included with at least one other flexibility option.
- Change in one variable correlated with the effect over storage (to establish a trade-off).
- Desired feature (but not mandatory): interaction between variables a function of RES penetration and CO_2 price.
- Based mostly on journal publications.

The section starts by discussing specific combinations of flexibility options and quantifying the trade-offs based on the different studies, followed by an overview (Table 1) that maps the area covered by each study and allows identifying unexplored combinations, besides highlighting the type of storage that was considered and the ones that consider the cost impact. Note that this is not the overview of all the studies considered for this publication, but instead is the overview of the studies for this Section. Finally, some key conclusions on the role of seasonal storage are specially extracted to make the link later with P2G. Note that this section is based mostly on power models, that provide a better granularity to quantify the trade-offs (this is also seen in Table 1), but the few ones exploring further than power are highlighted in Section 4.4.

[2] DSR is when the users change their demand as response to changes in price (or payment schemes) and DSM is related to management of loads to maintain grid stability (e.g. smart grid).

Table 1
Studies analyzing interaction between variables and quantifying the impact of power storage.

Reference	RES Management Strategy						Storage Type				Geographical Coverage							
	Wind/ Solar	Balancing	Network expansion	Excess of Capacity	DSM	Flexible generation	Generic	PHS/ CAES	Batteries	P2H/P2G	National	Europe	US	Global	Heating	Mobility	Fossil	Cost
Heide 2010 [62]	x						x					x					x	
Heide 2011 [18]	x	x		x			x			x		x						
Esteban 2012 [73]	x	x							x		x							
Aboumahboub 2010 [43]	x	x	x				x					x		x			x	x
Schaber 2013 [44]	x		x	x				x		x	x	x		x	x		x	x
Haller 2012a [13]	x		x				x										x	
Schmid 2015 [86]	x		x	x			x					x						x
Lise 2013 [55]		x	x		x	x	x					x						x
Schill 2014 [47]						x	x				x							
Steinke 2013 [19]		x	x					x	x	x		x						x
Pfenninger 2015 [53]	x		x				x				x						x	x
Krakowski 2016 [52]	x			x	x		x				x						x	x
Budischak 2013 [84]				x					x	x			x			x	x	x
Denholm 2011 [48]	x					x	x						x					
Thien 2012 [87]	x		x					x	x	x		x						x
Breyer 2012 [64]	x									x	x			x				x
Rasmussen 2012 [50]	x	x		x			x					x						
Becker 2014 [63]	x	x	x				x						x					x
Weitemeyer 2015 [71]	x			x			x				x							
Strbac 2012 [7]		x				x	x				x							x
Sisternes 2016 [46]	x					x		x	x				x					x
Bertsch 2016 [42]	x	x	x		x	x		x				x					x	x
Bussar 2016 [88]	x	x	x					x	x	x		x						x
Thien 2013 [89]	x		x				x		x			x						x
Huber 2015 [90]	x	x	x	x					x			x						x
Solomon 2014 [75]	x	x	x	x			x						x					x

4.1. Wind / Solar generation ratio and storage

It has been proven [18,19,62,63,71,72] that optimal wind and solar generation ratios can reduce the storage needs. The difference for a sub-optimal wind/solar ratio can be up to a factor 2. In [62], the optimal ratio led to a storage size of 1.5x the monthly demand (in energy terms), while a 100% wind only scenario led to 2.7x. This will be more pronounced, the more inefficient the storage is (i.e. more critical for P2G than for PHS, where the former one will result in a larger storage requirement). Optimal ratios also reduce the excess of capacity needed to satisfy the load, to only 15% with optimal ratio from almost 85% in a wind-only scenario. In [73], the storage is reduced by half by having the optimal ratio (2:1 solar/wind for Japan) in comparison to having only wind. The use of optimal ratio between wind/PV has a larger effect on storage than the installed excess of capacity [18]. In [71], the optimal ratio allowed increasing the VRE penetration from 40% to 75% with the same installed capacity (more energy used to satisfy demand rather than curtailed). In [74], the shift from PV to wind as main VRE resource, shifted the storage need from short-term (batteries, PHS) to long-term. In [72], the use of optimal wind/solar led to a 25% higher VRE penetration for a storage size of less than 0.1% of demand. It also translated into lower energy capacity needed (from 100 h to just around 20 h), lowest backup capacity and lowest amount of energy lost

4.2. Balancing needs and storage

Balancing capacity is directly related to the efficiency of the storage. For ideal (100% efficient) storages, the balancing requirement can be around 5% of the annual power demand, while a 60% efficiency would make it unfeasible (> 100%). Thus, a less efficient storage has to be compensated with additional RES generation capacity, where to get the same benefit (i.e. only 5% of storage needed) an excess of capacity of 25% is needed. For balancing, the optimal wind / solar ratio makes a big difference, where with 25% excess capacity, the balancing requirement can go up to 20% (instead of 5%) if only wind is used [18]. Hence, for every system, there is an optimal combination of balancing power, storage size, wind/solar ratio and excess of capacity. To give an order of magnitude for the balancing need, it is estimated that the EU-27 would require around 800 GW for 2030 with a 70% RES penetration [55].

It has been seen [50] that there is a synergistic effect of storage, balancing and excess of capacity, where only 10% excess of capacity combined with 6 h of storage equivalent can reduce the balancing need to 8–10% of the annual demand, while no storage can result in almost 2x the need. Similarly, balancing can be reduced by installing excess of capacity. Although it would require significant surplus to achieve similar reduction (power generated 2x of demand) [18]. The storage needed for balancing is short-term (few hours), where high round-trip efficiency is more critical than large energy capacities.

4.3. Transmission and storage

In [43], 100% RES systems were studied at the European and global scale, without storage or transmission, the system required 100% excess of production at the European level and almost 60% at the global scale. Optimal transmission expansion could reduce these values to 30% and 45% respectively, while storage reduced it to 20% and 45% respectively. The benefit was seen with only installed power capacities equivalent to 0.3% and 0.04% of the European and global power demand respectively. Hence, a small storage led to large benefits. A disadvantage of this study is that the cost comparison for network extension and storage was not done simultaneously. However, it can be inferred that storage capacities of 14–16 TWh would be much cheaper than several transmission lines of 100 GW range. These effects were achieved with storage being used for intraday balancing (rather than weekly or seasonal).

In [19], the relation between storage, transmission and balancing needs is determined for the entire set of combinations in Europe. Balancing needs are expressed as a function of the storage time (0–90 days) and the degree of interconnection (25–3000 km[3]). Batteries, PHS and hydrogen were considered as storage technologies and the costs were calculated for each one. The RES fractions were 100% and 130%. As a result, the balancing needs and costs are moderate with a maximum of 7 days of storage and a copper plate radius of 100 km (national level). The use of hydrogen as storage technologies results in higher overall costs and batteries result the best option (since no long term storage is required). The market potential is also determined as 50–70 bln €/a in Europe.

In [75], the effect of transmission capacity, storage and energy lost (i.e. curtailment) over RES penetration for a fixed capacity was analyzed for California. The storage used was the equivalent of up to 5 days of average demand, which was enough to reach the state where further additions of energy capacity would not result in higher penetration. The storage was equivalent to less than 0.1% of the annual demand (in energy terms) with energy to power ratio of 9–17 h. The use of the grid for matching the supply and demand patterns, allowed the penetration to reach 80%, with further expansions of the grid providing limited benefit in further penetration. Having both storage and transmission resulted in the lowest energy lost and generation capacity needed to achieve a fixed penetration (80%), where the largest contribution was from storage.

One study that does look at both sectors (power and gas) including key flexibility options is [44]. It covers a detailed specification of the storage, transmission and generation parts in Europe and the world. Additionally, the interaction between wind/solar ratio, excess of capacity, storage, RES fraction, degree of interconnection and diversification to heating is considered. Storage needs are almost doubled if only national grids are considered and they steeply increase for fractions higher than 70% RES, even making 100% RES not feasible. Supplementary capacity of 80–100% of the demand is needed without transmission extension, decreasing to around 30% with an optimal grid across countries. At global scale, optimal transmission reduces the storage need by 3x. The downsides of such benefits is that the transmission network needs to increase its capacity by almost 100% and an investment of 80–110 billion € required for it. This translates to 1.5–2.5 €/MWh higher electricity cost. However, it should be noted that scenarios by IEA already include networks expansions of 50% accounting for more than 300 billion $ every year (this also includes the replacement of lines reaching their end of life and cumulative of 8.4 trillion $ for the 2015–2040 period), just to maintain the quality of the service to existing customers and provide access to new users and new sources of generation [3].

It has also been shown [13] that transmission and storage have a synergistic effect to decrease the average electricity and CO_2 price and be able to reach more challenging targets for CO_2 emissions at a lower cost. In a system without transmission expansion, but only storage, the CO_2 price starts going up when a target of 70% CO_2 reduction is set, while having both delays this point to 80%. Systems with both allow reaching lower levels of curtailment and therefore higher capacity factors for RES leading to a faster penetration [54].

In [53], the entire range of combinations (0–100%) were analyzed considering nuclear, fossil and RES introducing storage, grid expansion, tidal, CCS and imports for UK and doing the cost optimization of the system. Deployment of grid storage was the only one allowing meeting 100% of the demand (i.e. storage is required for achieving a 100% system). However, similar CO_2 footprints of the system were achieved with for example 80/20 of RES/Nuclear at a lower cost. The use of only 6% of the installed generation capacity as storage allowed reducing the generation capacity by 20% since the surplus was not

[3] This distance represents the radius of the assumed copper plate, where 25km represents the resolution of the weather data, 100km a regional level, 500km equivalent to national and 3000km equivalent to a copper plate in the entire Europe.

needed to cover all the peaks in demand (for 80% RES). For high (> 90% RES), the use of storage was (40%) cheaper than the network expansion to meet the demand.

In [7], the addition of 5 GW of storage (average demand for the system was around 60 GW), reduces the transmission expansion needs by 20% using a 24-h storage. The nature of the storage (bulk vs distributed) also makes a difference in the transmission replacement. Using bulk storage, reduced the transmission expansion from 6.4 to 5.7 GW, while distributed actually increased it to 8.4 GW.

Transmission can substitute short-term storage and replace the need for energy transfer in time for space distribution. This can be a better way to reduce generation and storage installed capacities to achieve a lower system cost [74].

4.4. Transmission, storage and diversification to the other end uses

Another option is to use the power surplus in the heating sector. An advantage of this approach is that it defines the minimum bound for the electricity price. With a large power surplus, the price would no longer go to the zero vicinities, but would acquire the price of the fuel gas replaced (e.g. gas in heating). This is assuming a low power demand will not coincide with a low heating demand and if so, that the power surplus can be easily absorbed by the heating sector, which is a reasonable assumption since power represents around 20% of the global primary energy consumption, while heating represents almost 50% [3], where in spite of a seasonal mismatch between solar and heating demand, this sector should be able to absorb the power surplus.[4] Another advantage is that it contributes to the decarbonization of the other sectors by increasing the use of renewables. Furthermore, the conversion to heat is much cheaper than either the electrolyzer and methanation or only the conversion to hydrogen. The ratio of Capex can be 4-8x lower [76].

In [44], it was concluded that power to heat coupling represented a better option than P2G or the use of long term electricity storage. Various combinations were considered including grid expansion, coupling to heat, to hydrogen storage, to hydrogen used for mobility or its reconversion back to power with the possibility of methanation. The results indicate that with an RES fraction of 15%, heat coupling can deal with all the power surplus (~5% of power demand), while with fractions approaching 70%, heating can only absorb around 25%, leaving a 10% that can be dealt with spatial interconnection (i.e. grid expansion). Only in scenarios where no coupling to the heating sector was possible, then hydrogen storage turned out to be attractive, but its size still limited by only reaching around 3% of the average power demand. On the other hand, methanation was only attractive if no coupling to the heating sector was allowed, a high gas price (to pay for the investment) and no interconnections were considered (i.e. too many conditions). Only in this case around 20% of the power demand was transformed to hydrogen, of which half was converted further through methanation. The diversification to heat allows handling RES fraction of up to 50% without major network expansions. Above this value, both interconnection and diversification to heat complement each other. A similar conclusion was found in [77], where the use of electric heaters to use the power surplus for satisfying the heat demand was more attractive (i.e. lower costs) than P2G for the same capacity, in spite of P2G being able to reduce the most the power surplus fraction.

Even when there are more options for storage like plug-in hybrids, the hydrogen conversion continues to be the last option. In [78], most of the storage need (around 7–10% of demand) is satisfied with electric heaters when all the options (also PHS, H_2 and plug-in vehicles) are available. Hydrogen is selected as storage option when is the only option in the system. The use for the hydrogen is in the mobility sector rather than its re-conversion to power. Two notes on this study are that hydrogen was not compared individually to the other storage options and that the fraction of VRE in future scenarios was only around 10% (around 70% of the energy provided by nuclear and coal with CCS).

Hence, when the wider energy system is considered and other alternatives besides power only are considered, it seems that there are options more attractive than storage. The low cost of Power to Heat favor this alternative and even the diversification to transport is preferred.

4.5. Transmission, storage and demand side response

In [79], the flexibility options are evaluated for a variable RES penetration with focus on the 40–70% where curtailment might start becoming prohibitively expensive. The impact is quantified per individual option, but also some combinations among them. The effect of network expansion and storage reduces curtailment (for 60% RES) more than the double the amount of reduction achieved by DSR for the same power rating (i.e. 3 GW).

In [80], the same options were evaluated (considering V2G[5] as DSM) for an European scale with time aggregation to represent a year (2050). The objective was to minimize the peaks in residual load by displacing them in either time or space, but the cost was not explicitly mentioned. The largest reduction in residual loads is due to the use of electric cars connected to the grid, with a larger effect than storage. This might be related to the size used for the technologies (13 GW for storage, while it was 266 GW for V2G[6]). However, V2G effect might be low in terms of added costs to the system (< 1% total cost), where the more relevant property is to be able to use the cars to store the power surplus rather than using them to provide power back to the grid [81].

A more balanced capacity was obtained in [42], where storage even delivered 50% more energy throughout the year than DSM (75 TWh vs. 50 TWh) with respective capacities of 66 and 90 GW. These results were for the year 2050 with a demand of 4170 TWh, obtained with a combined investment and operational model for the power sector with a penetration of 75% RES (only 36% VRE).

Storage benefit (lower cost in either Opex, generation, transmission, distribution) is greatly reduced when DSR is considered. A flexible demand of only 20% of the peak demand, can reduce storage benefit by almost 80% [7]. DSR can replace peaking units and enhance system reliability by providing additional reserve. DSR can be attractive even when considering the same cost as a peaking unit [82].

4.6. Flexible generation, storage and curtailment

The storage size (energy rating) and capacity (power rating) are influenced by the must-run (base) load in comparison to the demand and the amount of curtailment allowed. The larger the base load, the higher chances that there will be an energy surplus from RES and that storage is needed. There will be cases where it is not worth to recover the surplus since these are only for a limited number of hours during the year. Hence, for the power surplus occasions, there is a trade-off between the amount of curtailment that is allowed in the system and the storage size. The more energy is allowed to be curtailed, means those extreme peaks of power surplus will not define the storage capacity and that there will be savings in the storage Capex. However, it also means that some energy is being wasted.

An example for Germany is available [47], where having around 20% of the demand as must-run can increase the storage size requirement by nearly 6 times, while increasing its capacity by a factor 2 (compared to the scenario where all the generation is flexible). At the

[4] Common ratios between maximum heating load in winter and minimum during summer are 8–10. Hence, the minimum heating in summer is equivalent to half the average electricity load (without heat pumps).

[5] Vehicle to Grid, which implies the use of electric cars connected to the grid as positive and negative storage.

[6] Assumption is a maximum of 76 million cars with 3.5kW of capacity for each one.

same time, allowing only 0.1% curtailment can reduce the storage capacity by half and 1% curtailment would eliminate the storage needs with fully flexible generation. Nevertheless, if the 20% of inflexible generation is considered, the effect is reduced, where 0.1% curtailment would only reduce the storage by 20% and 1% would reduce it by a further 30%. These numbers were obtained for an RES penetration of around 50% (year 2032), but represent a point for the relation between the 3 variables.

In [75], doubling the storage (but still representing a small fraction compared to the demand with the change being equivalent to 0.0005–0.011%) resulted in a reduction of the energy lost from 15% to 12% (for a fixed penetration of 80%). This shows the effect a small storage addition can have for a high RES system. Similarly, [83] looks into the added effect of flexible generation, where this defines the maximum penetration storage can achieve regardless of its size (i.e. for a fixed flexible generation there will be an upper limit for the penetration, which storage alone cannot overcome). When the storage power capacity is equivalent to the peak demand, having a fully flexible generation allows reaching penetrations of almost 90% (accepting a 20% energy loss), while the penetration is only around 35% (for the same energy lost) when only 70% of the generation is flexible. This is achieved with storage sizes of only 12 h for the fully flexible case and 4–5 h for the 70% flexible.

In [41], the addition of a 24-h storage allowed reducing the curtailment from 8% to 16% to around 4% for a range of RES of 20–50%. In [7], the use of a 24-h storage reduced the curtailment by 1/3 in a 25–30% RES scenario with a high cost for the storage, where the curtailment can be reduced by almost 85% for the low cost sensitivity and an equivalent storage capacity of 7% of the generation installed capacity. Furthermore, improving the flexibility parameters of conventional generation, reduced the possible benefit that storage can add by 50% for the initial capacity, with smaller impact as the storage capacity increases.

In [7], adding only 5 GW of storage (average demand for the system is around 60 GW), reduced the curtailment from 100 TWh to 40 TWh. The marginal curtailment reduces as the storage capacity increases, reaching a curtailment of around 10 TWh for a storage capacity of 25 GW (last 7 GW only reduce the curtailment by ~6 TWh). Therefore, the initial storage addition has a larger effect than subsequent capacity expansion of storage (diminishing marginal benefit).

4.7. Excess of capacity and storage

[84] analyzes different storage technologies (hydrogen, batteries and vehicles integrated in the grid) with an RES of up to 99.9%, capacities for each technology (including fossil) and the storage (both power and energy rating) is done. Results show that for higher RES both larger storage and larger excess of capacity are needed. However, the continuous relation of excess of capacity and storage was not done. This was done in [18] where the storage is expressed as a function of excess of capacity, wind/solar ratio and RES fraction. In [71], the storage enabled reaching higher RES with smaller excess of capacity. The introduction of just 24 h equivalent of load, reduced the capacity installed from 3x the demand to 1x to reach 90% RES penetration. In US [85], a storage of 7–16% of the demand is required if all the energy is supplied with wind. However, if the installed is increased by 50% more, no storage would be needed.

The underlined statements in this Section aim to highlight the key messages that were observed throughout the studies: storage is necessary for achieving a lower cost in the system, round trip efficiency is critical, most of its effect can be achieved by the daily component rather than the seasonal and that as storage capacity expands its benefit decreases.

A difficulty of establishing relations between flexibility options as aimed above is that these relations can be different depending on the scale and granularity in the spatial and temporal scales. Grid expansion costs (and effect over storage) will be different if a node represents an entire country than if every node represents a small town within a region. Similarly, the power surplus and storage behavior is not fully captured (only through parametrization) in models that do time slice aggregation in comparison to the ones that actually look at optimal choices for every hour.

Below, Table 1 provides an overview of the flexibility options considered in each of the studies, the type of storage, the geographical level, if cost effect was considered, type of study and scenarios covered. Note that these flexibility options are the same as introduced in Section 3, while the "Sub-category" refers to the study classification introduced in Section 2.

From the studies captured in Table 1, some highlights are:

- The optimal ratio between wind and PV to decrease the storage demand is inherently considered in the studies that do cost optimization and it is determined in most of the studies.
- As expected the role of storage becomes more relevant for high VRE penetrations. Below 30% penetration, curtailment (if any, depending on the system) is the best option, since the number of hours where there is a surplus are not enough to justify an investment in any asset. To reach fractions > 80%, storage (and specifically long-term) plays a key role and reduces the overall system cost and even in some cases [13,53] is the flexibility option that makes the scenarios feasible. For intermediate RES shares, usually network expansion and DSM are preferred solutions before storage [55].
- Efficiency for storage is key, where lower efficiencies will decrease the revenues since less energy is being sold back to the grid and might make the storage use unattractive [19,46]. Furthermore, lower efficiencies increase the amount of storage needed in the system (increasing the corresponding investment) [18].
- Flexible generation is a difficult element to incorporate, since this involves considering the individual plants to have a UCDM[7] approach, which introduces MILP[8] and requires detail on the operational component of the model (usually associated with hourly resolution). At the same time, to optimize the installed capacities an investment module is needed. The combination of both steps with the integer component of the operational constraints might make the calculation algorithm too complex to be solved within a reasonable time.
- There is high uncertainty around DSM, where input varies widely depending on region and assumptions. The comparison of this alternative with storage depends mainly on associated cost and flexible demand assumed. However, given that its costs are usually associated to software and minor infrastructure, it has preference over storage.
- There are only a few studies focus on the global scale. A reason might be that with a larger geographical coverage, either the time resolution or spatial granularity has to be smaller. A further simplification can be the consideration of fewer flexibility options. Nevertheless, [91] is one of the most complete ones, tackling these issues (global scale, combined investment and operation optimization, inclusion of operational constraints, grid expansion and H_2). A key limitation is that because of the scope of the study only the power sector was analyzed.
- One of the most complete studies focusing on the broader energy system is [44] with an European and German scale, focusing on the grid expansion and diversification to Heat.
- A space that remains relatively unexplored is to quantify the cost increase due to lack of flexibility options in the system. Usually, when a model is able to capture the behavior of a flexibility alternative, the tendency will be to exploit it. Studies that do look at the absence of one of them (e.g. [43]) have limited scope and require a more systematic approach.

[7] Unit and Commitment Dispatch Model, referring to modeling individual plants and their state for every time step.

[8] Mixed Integer Linear Programing which includes the integer component for the operational state of every plant.

4.8. Role of seasonal storage

Below the seasonal component is specifically discussed, to be able to make the link later with P2G.

In [71], the VRE integration was evaluated for an efficient (80%) storage with few hours of capacity (4 h) vs. a less efficient (30%[9]) and with longer duration (168 h) storage. For VRE fractions lower than 82%, the more efficient storage results in more use of the installed capacity and less curtailment. Above such percentage, the performance of the longer term storage was better. Some caveats are that this was only from a time-series perspective, matching production and load (i.e. without cost) and only considering optimal wind/PV ratio and storage.

In [47], a similar approach (of considering time series and with focus on power surplus for the different must-run, RES penetration scenarios) was followed with the advantage of making the split between hourly, daily and seasonal storage. The seasonal component stays constant at around 10% of the average demand in power capacity, while the daily component provides most of the benefit depending on the degree of curtailment allowed. With no curtailment allowed for 80%, the installed capacity for storage is equivalent to 100% of the demand with a split 90/10 between daily/seasonal components. However, no mention is done to either hours of storage or cycles over a year to relate the total energy stored over a year (or power surplus) with the energy rating.

In [92], the order of alternatives to deal with the power surplus is: charge the short-term storage (batteries), then PHS, P2G, use in electrical heat pumps, directly use in heat storage and curtailment if there is any surplus. For this system, the heat storage is actually used for the seasonal component. Its total output throughout the year (not its storage capacity) is equivalent to 25% of the total demand. Furthermore, this option only starts being charged once the first three storage alternatives have been charged.

A set of studies [87,88,93,94] have used a tool for power optimization based on operational cost. The advantage has been the split in different time scales for the storage (batteries, PHS and hydrogen) with the separate sizing of charging, discharging and storage capacity for the long term component. Disadvantages are that only storage and (HVDC) transmission expansion between countries is considered (i.e. no flexible generation with individual plants or DSM). Furthermore, the cost for the charging and discharging components seem to be on the optimistic side (300/400 €/kW). The system is based on 100% VRE (only wind and solar for 2050) with a demand of 6250 TWh for the EUMENA region. In spite of finding the optimal PV/wind ratio (60/40), most of the regions are highly dominated by a single one of them, which might make the imbalances larger. The long term (H_2 in this case) storage demand is 800 TWh with a range from 480 to 1160 TWh depending on the investment prices and resources assumed. This is much larger than PHS and batteries which stand at 0.5–7.6 and 0–3.2 TWh. In terms of power capacity, the long term storage has 900 GW, while it is 190 and 320 GW for PHS and batteries, compared to an average power demand of ~700 GW.

In summary, it was seen that there was a seasonal storage component in studies that were either not doing a cost optimization or had limited flexibility options. As soon as the value of storage is considered and related to the size, the effect of decreasing marginal benefit [7,23,26,95,96] will decrease the required capacity.

5. Cost contribution of storage

A distinction from the studies mentioned before is that not all of them consider the choice based on cost optimization. In some cases [19,51,62], the trade-off for determining the size is done based on potential, full load hours and resources distribution. In this section, the intention is to highlight on how storage affects directly either investment cost or electricity price. Therefore, the main criterion used for study selection in this section was that the system cost was assessed with changes in storage size.

The elements that contribute to a lower cost due to the use of storage are:

- Lower fuel costs. Storage is meant to absorb the temporal variability of renewables, reducing the number of times conventional generators have to change their output. Storage in some cases provides the balancing service in the short time frame. In most cases, this is provided by gas turbines that have a low investment and are the best option for low operating hours and where most of the costs are represented by the fuel consumption. Storage would be saving the use of this fuel for peak supply purposes. It can also provide lower fuel costs by allowing the operation at a higher efficiency due to a higher load.
- Lower curtailment. When there is power surplus but no demand to use it, energy can be stored for a temporal displacement, this will effectively reduce the energy wasted and increase the VRE fraction in the power system since that energy will be used later displacing conventional one.
- Lower generation investment. When storage provides the balancing function, the backup and balancing capacities needed are lower.
- Lower network investment. In areas where network lines are congested during peak demand, the energy could be stored at the node during low load hours reducing the need for expansion and producing a more stable load of the network.

These savings should offset the investment and operational costs for the storage. Furthermore, the above benefits cover a wide range of sizes, time responses and time frames since for example to avoid grid congestion a longer term planning has to be done representing different applications (from adequacy to operational reserves) that will most likely not be covered by a single technology.

A complete study looking at the interaction between 5 of the variables (storage, transmission, curtailment, DSR and flexible generation) is [67]. In this, different sensitivities were done to understand the interaction between the variables and quantify its impact on system cost. The area of focus was North West Europe divided in 6 regions and with RES penetrations of 40%, 60% and 80% in 2050. The impact of individual changes in each of the variables was quantified in terms of total generation costs. The focus was on the power system with 1-h resolution. Storage included the currently installed PHS capacity with the additional capacity being CAES due to its lower LCOE (considering a 40% reduction in specific cost to 2050). No P2G was included due to the high cost. Storage increased the system costs for every RES penetration analyzed in the order of 2% of the total cost for a capacity of up to 20% of the peak load. Transmission reduced the cost only after 60% penetration and up to a limited degree (3.5x current capacity). A 15% potential of DSR (capacity in relation to demand) reduced the overall costs by 1.7–2.5%. Curtailment only reached 2% (of the RES production) for 80% RES penetration. VRE increased the capacity factors for gas turbines and hydro, while decreasing it for the rest of technologies. Some limitations of this study are that it covers only the power sector and options like Power to Heat or P2G are not included, it considered a limited technology portfolio (excluding biomass options or CHP), there were only 6 regions included disregarding transmission limitations within those regions, it does not consider the legacy plants (i.e. optimizes for 2050 assuming it is all new), no price premium is considered for flexible natural gas supply and there is still uncertainty around the cost and capacity available for DSR.

In contrast to [54], the presence of storage reduces the overall cost for the system by 2% points and this difference remains similar with greater transmission expansion rates. For this case, the model is also power only

[9] This can be typical for the round trip efficiency of P2G with efficiencies of: Electrolysis = 75%, Methanation = 80%, Compression = 80%, Transport = 90%, CCGT = 60%.

aiming to bridge the gap between operational optimization and long term investment with a case study being a simplified 3-region area for testing the approach. The same model was used for a more realistic case, in the EU-MENA region [13], where in terms of costs, the CO_2 price and the electricity price are quantified with the presence or absence of storage and transmission expansion with a constraint being the CO_2 reduction target for the region. Without neither storage nor transmission, the electricity price almost doubles at around 90% CO_2 reduction target (from 7.8 €ct/kWh to 15 €ct/kWh). The presence of storage allows reducing such cost to around 10 €ct/kWh for the same level of reduction or achieve almost 98% CO_2 reduction for the same electricity price. As expected, the lowest costs are achieved when both options are available, being able to achieve 100% CO_2 reduction with an electricity price of 13.5 €ct/kWh or 90% CO_2 reduction at 8.5 €ct/kWh.

More drastic results are obtained in [53], where the LCOE for the entire system is reduced by 40–50% for all the sensitivities (with and without grid extension, CCS, tidal and import of solar) when storage is considered with a storage cost of around 375 £/kWh with the benefit being 1–2 £ct/kWh in LCOE (depending on the case and compared to a base price of 8–13 £ct/kWh) per every 100 £/kWh reduction in specific cost and the benefit becoming much larger for prices lower than 75 £/kWh. For this case, grid-scale batteries with an efficiency of 90% were considered and even though the sensitivity up to 375 £/kWh was done, the base case considers a specific price of 42 £/kWh, which seems to be on the optimistic side for batteries considering its lower energy rating.

Analysis of the North East Asia system with consideration of transmission, storage and gas demand for a 100% system, led to storage being around 40% of the electricity cost with much smaller contribution of transmission (5–10%) [74]. It resulted much cheaper to improve the connections among regions rather than increasing the storage capacity. Improving transmission actually led to 14% decrease in electricity cost due to lower generation capacity and storage, while satisfying the gas demand with long term storage (P2G) led to 13% increase in electricity cost, caused by larger generation and electrolyzer capacities to ensure that the operating hours of P2G are high enough to continuously satisfy the gas demand. This option of long term storage to satisfy gas demand resulted in 250%, 51% and 209% cost increase (€/MWh) for curtailment, storage and transmission costs respectively.

Nevertheless, that is the only study from the Neo-Carbon project (see Section 5) that led to an increased cost due to the addition of the P2G and gas demand. For most of the studies, there was actually a price decrease with a range of 13–20% for the total electricity price and 30–87% lower for the storage cost. Some reasons for a lower cost when the (industrial) gas demand is considered are the increased utilization of wind and solar resources, better utilization of mid-term storage and higher flexibility due to the coupled system. Storage costs decrease since the diversification to other sectors (in these cases only industrial gas demand and desalination, but the effect will be larger for a larger demand in other sectors) reduces the need (and size) of long term storage.

In [46], a power model is used to study the ERCOT area in US. The demand being 97.1 GW and storage sizes of 10–30 GW are used with a low (2-h) energy rating represented by batteries and a high (10-h) one being PHS. Future (2035) scenarios with up to 75% non-fossil generation are envisioned and the sensitivity is done with the absence of nuclear. A CO_2 footprint constraint on the system is imposed to achieve up to 90% reduction with respect to current values (550 gCO_2/kWh). In the scenarios with nuclear, the 2-h storage did not change the electricity LCOE up to 20 GW and increase around 3% for 30 GW, while the 10-h storage reduces the cost by 2% with 10 GW and a further 1% point with 30 GW. This is slightly different with the absence of nuclear, where the 2-h storage does not make a difference in cost and 10-h storage can reduce it up to 7%. When these savings are compared to the storage cost, only the addition of the first 10 GW are profitable, since subsequent additions reduce the benefit (i.e. marginal increment is smaller).

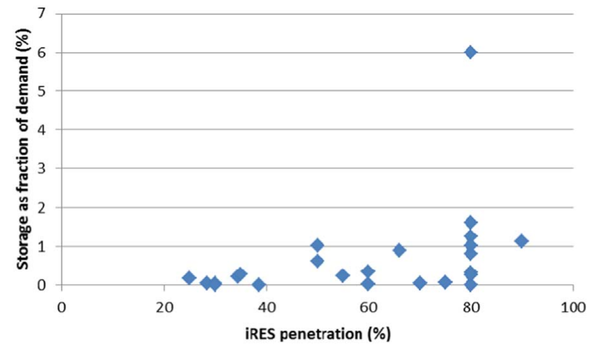

Fig. 4. Storage energy size as a function of VRE penetration for systems with less than 100% RES.

The absence of hydrogen storage as long term alternative, increases the cost of electricity by 20% in [88], where most of it needs to be compensated by PHS.

A study in UK [7] quantifies the annual savings for introducing storage in the system (both bulk and decentralized) as a function of storage cost and VRE penetration (2020–2050). The storage cost reduction needed to increase the total cost savings is larger for higher VRE fractions. Hence, for 2020, annual savings triple (from 0.2 to 0.6 £bln/year[10]) with a cost reduction of 2x for storage (46 vs 25 £/kWyear), while for 2050, a cost reduction of 20x (1000 vs 50 £/kWyear) only leads to annual savings 1.5x higher (12 vs 8 £bln/year). A change in the main driver for the savings is also seen as the VRE increases. For low VRE (2020), the largest contributor to the savings is the Capex for generation, while for 2050, the Opex (e.g. fuel) component increases its share to around 50% of the savings (the other 50% being generation Capex). Similar savings, cost structure and capacities are found for both bulk and distributed. The cost savings are also dependent on the RES contribution to the low carbon mix (50 gCO_2/kWh target). Scenarios relying more on nuclear or CCS, found the annual savings to be almost zero (from > 8 £bln/year).

6. Quantifying storage needs

6.1. Storage demand

A key variable that defines the storage requirement is the fraction of energy supplied by VRE, since they are an additional source of variability. This requirement can change by the absence or presence of other flexibility options as highlighted in the previous section. Nevertheless, to have an order of magnitude of the storage requirement, several studies were reviewed aiming to capture the storage size as a fraction of the annual demand and VRE penetration. This is presented in Table 2 for systems with penetrations 20–90% (transition period) and in Table 3 for systems with 100% RES penetration (sustainable long-term target and not necessarily full 100% VRE). The storage size is expressed as a function of RES penetration in Fig. 4 to identify if there is a trend in the values.

The criteria applied to screen the studies in Table 2 were:

- The storage capacity had to be the outcome of an optimization process. Therefore, studies like [51,62,71] were excluded since they provide insight into the interaction of the variables, but do not give guidelines on what is the best choice. An exception for this were the set of results as part of the Store project, which was included for its consistency in the approach to determine the storage needs, for having a fixed scenario for 80% RES and to illustrate that even in this case of high (RES, but not VRE) penetration, the amount of

[10] These results are with a generic storage of 75% efficiency and 6h duration.

Table 2
Storage needs for systems with less than 100% RES (studies ordered by increasing fraction).

Country	Annual Demand (TWh)	Storage Size (TWh)	Storage fraction (%)	VRE fraction (%)	Sectors covered[a]	Notes	Reference
Spain	375	0.66	0.18	25	P	Low capacity factor for PHS	[98]
Netherlands	123	0.05	0.04	28.3	P	6% cost reduction	[99]
West Europe	4647	2.4	0.05	30	P	Assuming 8 h of storage	[49]
UK	~700	0.06	0.01	30	P	Average demand not explicitly given	[7]
Ireland	32.7	0.07	0.21	34.5	P	All wind and 2 GW charger	[100]
Germany (Region)	53	0.15	0.28	20–50	P	Only mentions 24 h of storage	[41]
Germany	478	0.06	0.01	38.6	P	Low curtailment with current foreseen PHS capacity	[101]
Germany	562	3.5	0.62	50	P	No must-run in 2050	[47]
Greece	88.3	0.4–1.4	1.02	50	P	Depending on feed-in limit	[102]
Austria	83	0.2	0.24	55	P	Scenario C 2050	[103]
UK	300	0.1	0.03	60	P	Power rating of storage is 50% of generation capacity. 80% of it is batteries.	[53]
Spain	420	0.6–2.2	0.33	60	P	Power rating of 35 GW	[98]
Germany	2030	18	0.89	66	PH	Heat, power and H2 demand	[44]
Europe	4170	1.8[b]	0.04	70	P	Assuming 24 h of storage	[42]
US (Region)	510	0.3	0.06	75	P	Energy to power ratio of 2/10	[46]
US (Region)	300	0.034	0.01	80	P	Energy to power ratio of 12	[48]
Belgium	268	1.3	0.32	80	P	Around 120 h of storage	[104]
Denmark	41	0.66	1.61	80	P	All VRE from wind	[105]
Germany	413	0.9–1.3	0.27	80	P	Avg. 46 GW charging	[101]
Germany	~600	7–8	1.25	80	P	Maximum of various studies	[106]
Germany	586	0.5	0.09	80	P	Lower system cost	[107]
Germany (Region)	22.7	0.184	0.81	80	P	Gas storage starts at 70% RES	[108]
Ireland	45	2.8	6.00	80	P	Charger of 7 GW / All wind	[100]
Europe	4900	50	1.02	80	P	125 GW	[109]
Europe	4900	50–60	1.12	90	PH	Only up to 800 h of use	[110]
EUNA[c]	5418	17	0.31	94	P	20% from CSP	[111]

[a] P = Power, PH = Power + Heat.
[b] It has effectively the same capacity as the reference year (2008), i.e. no expansion needed for 2040.
[c] Europe and North Africa.

storage needed is still relatively small (in energy terms, compared to the annual demand).

- The storage size (either power or energy) had to be mentioned in order to estimate its fraction with respect to the demand. An example of an excluded study is [55], where the hour by hour optimization is done considering six adaptation measures to deal with intermittency. It covers EU-27, considering different scenarios that originate from a review of European scenarios and it considers variable RES penetration. However, the focus is on cost comparison among options, savings produced and effect over residual load, while not explicitly mentioning the requirement for each adaptation measure. Other studies (e.g. [77]) seem to deal with annual quantities of energy exchanged rather than a single cycle or do not give the equivalent hours of storage.
- The optimization algorithm should have an investment component that determines the optimal storage capacity. In some cases [67,97], the focus is on the operational performance (e.g. constraints of conventional plants, network congestion) and the storage capacities are not endogenously defined, but instead fixed as an input.

A general observation from Table 2 is that even for high penetrations of 90%, the storage size is at most 1.5% of the system demand. This would mean that even considering an electrification of the heating and mobility sector, where the power demand rises from current 24,100 TWh [5] to around 40,000 TWh [3], the storage size needed would be in the order of 600 TWh.

There are two factors to have in mind that can change the magnitude of this number (1.5%). One is that most of these studies only focus on the power sector. Therefore, including the heating sector might make the need larger if the mismatch between profiles (i.e. residual curve) is larger, but at the same time it can make it smaller by the introduction of additional flexibility options (Power to Heat, Power to Liquid). The other one is that some of the studies do not make the split between daily and seasonal storage and in most cases, the storage is associated to compensating the variability of RES (i.e. sudden fluctuations and balancing needs). Thus, most of this storage is not in the space of P2G and seasonal.

In Europe, stoRE project[11] aimed to look in more detail at the storage needs for 2020 and 2050 scenarios (80% RES in the power sector). It was mostly focused on PHS as long term option, but the approach is generic looking at residual curves. For each country, sensitivities using an unconstrained capacity for PHS are done, which allow seeing the amount of storage needed to compensate short-term fluctuations, but also the seasonal trends. Most of the values shown in Table 2 are from such sensitivities. For some countries, part of the 80% RES is provided by PHS itself (e.g. Austria). Thus, only the contribution from VRE was considered for Table 2, being the main source of variability. A disadvantge of the approach taken is that uses residual curves and matching between RES supply and load. It does not look to the economical evaluation, cost optimal solution and comparison with other alternatives.

Based on [49], the expected storage needs for 2050 are between 190 and 310 GW globally. However, it must be noted that considers a conservative value for RES penetration (30%). Most of this storage is short-term and it shows that it can be easily satisfied without the need of having a massive storage infrastructure like the methane grid. In Europe [112], a split is made between the technical (includes technology constraints and system boundaries) and economic (considering cost and investment recovery) potential. The economic potential for flexibility requirement is around 60 GW or 70 TWh for 60% RES. For US, it was estimated [85] that for 100% scenario around 7–16% of the annual demand would be required as storage with a 50/50 split of wind/PV. A small addition of storage (24 h) can make a big difference in the flexibility of the system and reduce curtailment or power surplus drastically [48].

[11] http://www.store-project.eu/.

The odd value at 80% having 6% of storage requirement is a study done for Ireland as part of the Store project. Among the reasons for such a high requirement (in comparison to the rest) are: due to the location and VRE potential in the country, only wind was used. When the generation comes from a single VRE there is no complementary production and storage needs are the highest. Furthermore, the study quantifies the storage needed to avoid all the possible curtailment, aiming to establish an upper bound for the storage demand. Most likely, curtailing part of the energy (part of the residual curve that requires high power capacity only for a few hours a year) would be more cost effective. Finally, only the power system is assessed. In a country like Ireland, heating demand is high in winter, when the wind production is also the highest. Hence, part of the possible surplus could be used to satisfy such demand, rather than increasing the storage size needed. It should also be noted that in Ireland most (41%) of the heating demand (space, water, process) is supplied by oil and gas is second with 39% and where the electricity and heating sector have similar size (~30 TWh) [113].

On the low side, there are points that have a low storage demand. For 80%, [48] estimates that only 0.01% of equivalent demand is enough to reduce the curtailment from 33% to almost 10%. The largest effect being for the first 4 h. For this case, an 80% efficient storage was used, also the optimal wind/solar mix (70/30) and full flexibility in generation (no minimum load). Nevertheless, the model does the hourly match between supply and demand with certain penetration and thermal generation flexibility, where the options are storage or curtailment. This constitutes an exploratory step before the use of a techno-economic (UCDM) model. Hence, trade-off between flexibility options is not done based on cost (but based on the residual curve instead). In [46], 10 h of storage is enough to reduce the curtailment to 4% in a system with 75% VRE and the rest being CCGT. Even though the storage capacity is exogenous, sensitivities were done to evaluate cost and curtailment resulting in a power capacity around one third of the peak load.

As part of the Renewable Energy Directive (20% of final energy consumption from RES by 2020), some countries have a higher contribution from RES [114,115]. In Germany, it is set at 40% of the power sector (26% from VRE), Denmark aims for 52% power (31% wind), Finland has a 38% target overall driven mainly by a biomass, 33% in the power sector, but with only 6% wind in the power sector, while Sweden has a 50% target overall and 62% for both power and heating sectors (only 8% wind). These values show that some countries will have a high contribution from VRE as early as 2020 (which can be even higher for short periods of time) and that some of them have a higher reliance from a single source, where the mismatch with the demand pattern can be the highest.

Since the amount of storage required (in energy rating) is usually low (compared to the demand), the presence of flexible generation plants like biomass or the shift in the load (through demand response) can have the equivalent effect at a lower cost. Where storage is part of the best (low cost) solution, it is usually for short term (< 7 days) application [84], where batteries would perform much better due to their higher efficiencies. In the cases where seasonal storage is included, the possible value that could be captured by it is diminished when its influence in the price is considered.

It has also been repeatedly highlighted [7,25,26,46] that the larger benefit for storage is seen with the first addition of capacity with lower marginal benefit as the capacity increases. Hence, even in cases where there is a cost reduction for storage size increase, it is better to keep the storage small as a size increase is not justified by the decreasing benefit [116]. For price arbitrage, storage capacities larger than 24 h are not justified [96]. Furthermore, the energy arbitrage is one of the applications with the lowest value and higher profit can be obtained in the balancing and reserve market [27,117,118]. It has also been shown that the maximum useful service storage can provide quickly decreases as storage is added, having its peak at relatively low energy rating (< 0.01% of demand) [75].

Table 3
Storage needs for 100% RES systems.

Region	Year	Annual Demand (TWh)	Wind/Solar (%)[a]	Storage[b] (TWh)	Storage power (GW)	Storage fraction[c] (%)	Sectors covered[d]	Reference
ASEAN[e]	2050	1862	25/40	1.5	–	0.08	P	[90]
Asia[j]	2030	11,280+2768	35/46	300	558	2.14	PH	[119]
Australia	2050	260–323	6.5/32.5	0	–	0.00	P	[120]
Australia	2050	220	28/62	0.9[f]	61	0.00	P	[121]
Brazil[j]	2030	815+217	4/36	89.3	25.2	8.65	PH	[122]
France	2050	425	40/17	3	3	0.71	P	[52]
EUMENA	2014	4122	40/60	248	360	6.02	P	[93]
EUMENA	2050	6250	40/60	804	550	12.86	P	[94]
Eurasian[j]	2030	1450+667	58/14	70.3	105	3.32	PH	[123]
Europe	2007	3240	55/45	400–480	400	13.58	P	[62]
Europe	2050	4200	73/21	13.5	–	0.32	P	[43]
Europe	–	3240	55/45	25	360	0.77	P	[50]
Europe	–	3400	55/45	216	65	6.35	P	[89]
Europe	2050	4000	64/36	20	–	0.50	P	[19]
Europe+[g,j]	2030	7388+3188	50/30	352	587	3.33	PH	[124]
Germany (Region)	2030	19.9	55/40	0.53	1.5	2.66	P	[108]
Germany	2050	475	60/40	9.1	–	1.92	P	[71]
Germany[h]	–	509	77/17	0.8	50	0.16	P	[111]
Germany	2050+	1385	70/27	17.5[i]	87	1.26	PH	[125]
Greece	2050	55.7	100/0	2	0.2–0.3	3.59	P	[126]
Ireland	2050	125	13/2	0.24	10	0.19	PHM	[127]
India[j]	2030	2597+1620	31/45	208	115	4.93	PH	[128]
Japan	2100	1400	70/30	40	–	2.86	P	[73]
MENA[j]	2030	1756+3874	48/48	296	593	5.26	PH	[129]
Morocco	2050	28	37/63	1.1	–	3.93	P	[130]
North America[j]	2030	6059+2596	58/31	221	442	2.55	PH	[131]
North East Asia[j]	2030	9877+1245	51/33	407.6	452	3.66	PH	[74]
SE Asia[j]	2030	1629+608	22/44	43.1	118	1.93	PH	[132]
South America[j]	2030	1813+663	17/49	42.7	131	1.72	PH	[133]
Sub-Saharan Africa[j]	2030	866+199	31/50	24.3	54	2.28	PH	[134]
UK	2030	900	55/6	27	35	3.00	PHM	[135]
US (Region)	2030	276	97/3	2.9	58	1.05	P	[84]
World	2050	44,000	75/25	16.5	–	0.04	P	[43]

[a] Ratio between useful energy produced from wind and solar.
[b] Total energy that can be stored at any time and not energy delivered throughout a year.
[c] Storage energy capacity expressed as a relative number to compare across studies (normalized using annual energy demand).
[d] P = Power, PH = Power + Heat, PHM = Power + Heat + Mobility.
[e] Association of East Asian Nations.
[f] Storage provided by 15 h of CSP (i.e. no long term or other storage considered).
[g] Europe, MENA and Eurasia.
[h] Different scenarios were done with demand 500 and 700 TWh and connection to neighboring countries.
[i] Only fraction of P2G. Heat storage is 213 TWh and batteries 9 TWh. Only total storage throughout the year are mentioned rather than individual capacities. For P2G, it is assumed it is used 10 times a year (to translate annual use to energy storage capacity).
[j] These studies come from Neo-Carbon Energy project (see explanation below) and numbers for demand are split in power demand + gas and desalination demand.

6.1.1. 100% RES systems

The next step is to consider fully renewable systems to fulfill a long term goal of the system (i.e. sustainable development). The objective is to understand if the storage needs dramatically increase in 100% systems compared with the trends observed for transition scenarios (< 95%). This is shown in Table 3 while the cummulative number of studies as a function of the storage size is shown in Fig. 5.

Two key differences from Table 2 that only reflects the VRE fraction and focus on the power sector, the cases presented in Table 3 include all the RES and with half of the studies covering more than power. Hence, in some cases (e.g. France, Denmark), part of the energy is supplied by hydro, biomass or even imported energy and not necessarily only VRE. Nevertheless, most of the studies do consider only wind and PV.

Fig. 5 shows the cummulative number of studies that are below a threshold of storage. The intention is to illustrate that most of the studies actually require a small fraction of storage, with 80% (27 out of 34) having a storage need of less than 4% of equivalent annual demand and only 3 of them with a requirement of more than 8% (for explanation see below). Even some (3) scenarios not requiring any storage and making use of other flexibility options.

Some observations based on the different studies for 100% scenarios are:

- Even with a high contribution from only one VRE resource [84,111], the amount of storage needed is still 1–1.5% of the annual demand. This is in line with previous studies (e.g. [75]), where the energy storage capacity was even lower than the daily demand.
- For the ones requiring the most storage, [62] only looks at the time series and mismatch between solar and wind generation and power

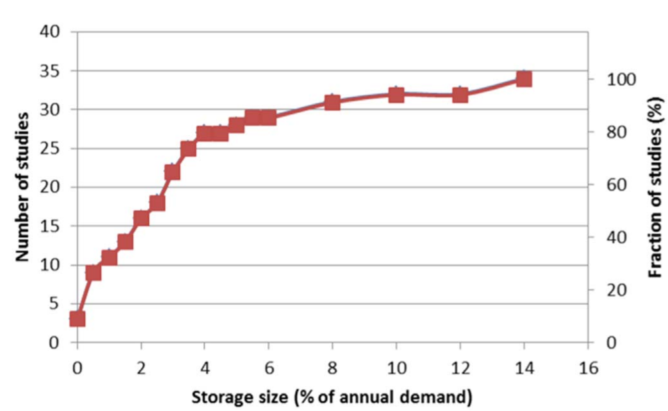

Fig. 5. Storage energy size as a function of VRE penetration for systems with less than 100% RES.

demand, without considering other flexibility options and choosing the cost optimal solution. It was included to show as reference, how much can the storage size increase if the optimization and trade-offs with the other options is not done. [89] has the same approach, but includes the grid extension and cost calculation, which already reduces the storage requirement by half. The same tool, with the same geographical coverage (Europe) is used in [93,94], where similar conclusions are reached, but showing the impact of grid extension on storage capacity, where an NTC maximum power between countries of 7.5 GW could reduce the storage by 4x the standard scenario. Furthermore, an optimistic investment for H_2 storage was used (300 €/kW).

- In [73], the storage capacity is provided by batteries, not by long term storage. Achieving such a high quantity of storage with such technology is briefly discussed, but remains unclear.
- Some of the studies, do not mention or consider power storage as part of their 100% scenarios. Thermal storage is used in combination with CHP provides flexibility to the system allowing decoupling the heat and power generation and no other type of storage is either needed or economical [120]. Hydrogen does play a role, but as diversification to the fuel sector rather than seen as storage, where around 12% of the annual primary supply is converted to H_2. Two thirds of the demand are satisfied by heat pumps.
- On the low side of storage, there is [43], where one of the reasons for such a contribution from storage is that there is a significant expansion of the network and around 60% of the total produced electricity is transported away from its source. Even though this is not compared relative to the current size, some of the links between countries are up to 1200–3600 TWh/year. Network expansion is the result of cost optimization and trade-off with generation and storage.
- For these 100% scenarios, a source of flexibility with zero-carbon is needed, this can be provided by CCGT with "green gas" [46], hydro generation and PHS [120,136], biomass CHP [137,90], thermal storage [120,125], PtL [135] or Power to Heat [44].
- In terms of the role of P2G and uses of the hydrogen or methane, hydrogen is used for transport [135], methane for back-up generation [135]. It is recognized that even though quantities are small in some cases, it plays a key role when RES generation is low and demand is high.
- An attempt was made to correlate number of flexibility options with storage size, also considering different weights for each alternative, but no reasonable correlation was found. This shows the high degree of complexity added by local, specific conditions that make the answer different in each case.

There are a set of studies done by LUT (Lappeenranta University of Technology) as part of the Neo-Carbon project[12] that look at 100% RES scenarios for different regions of the world. Advantages are the consistent approach, where the same assumptions, approach and model are used. These include splitting countries in several nodes (rather than a single node per country), the hourly simulation of the system, consideration of storage, transmission, curtailment and to some extent, the flexibility in generation, both Capex and Opex components are included in the objective function, storage is split in batteries, thermal, PHS and H_2/CH_4, scenarios include independence of each region within the country (i.e. no power exchange between regions), country energy independence and one where transmission is optimized along with the gas demand being supplied with P2G. Some limitations are that besides power, only the industrial gas demand and desalination are considered (i.e. heating and mobility demand not included yet), the individual power plants are not included (integer component), leading to the operational constraints not being fully captured, transmission costs are included as part of the objective function, where in most cases this is the most attractive solution, however most of the network costs are usually associated to distribution rather than transmission. It also has a separate prosumers model that optimizes the PV capacity based on profit for the consumer, effectively complementing the large scale PV deployment with the smaller scale.

Almost all the regions in the world have been studied by this project and currently it is expanding the scope to the entire gas system. P2G is a key technology since it allows satisfying the gas demand in those 100% RES scenarios. Its role is usually not significant for the scenarios that focus on power demand, but greatly increases when the demand is expanded to the gas system. The energy storage capacity is mostly between 20 and 25 days of equivalent power capacity (except for [122,128]) and the number of cycles a year is usually 0.4–0.5. The resulting storage capacity is 1.5–5% of the annual demand (except for [122]).

There is another set of studies looking at 100% RES systems by 2050 developed at Stanford University that focused mainly on US [138–143], but do have a study on a global scale [136]. These are based on purely WWS (Water, Wind and Solar), where technologies like nuclear, coal with CCS, biofuels and natural gas are not considered. The model includes hydrogen as alternative to satisfy part of the transport demand (heavy duty, ships, aircraft, long-distance freight) and high temperature industrial processes. It assumes a high electrification rate that results in a higher efficiency leading to a decrease in primary energy supply, combined with implementation of efficiency measures. It assumes energy independence for all the countries, where each one can satisfy their own demand. Even with these assumptions that might increase the flexibility needs, these scenarios use very limited storage, "No stationary storage batteries, biomass, nuclear power, or natural gas are needed in these roadmaps. Frequency regulation of the grid is provided by ramping up/down hydropower, stored CSP or pumped hydro; ramping down other WWS generators and storing the electricity in heat, cold, or hydrogen instead of curtailment; and using demand response." [142]. The storage priority is actually: first, store the heat surplus, then power (both as thermal storage) and only then use PHS, whereas demand response is used to shave periods where demand is higher than generation. Additional contributions are that this set of studies considers externalities (deaths) caused by air pollution, impact on job creation and earnings and a timeline representation with policies to be applied at different time horizons and different sectors. However, note that the study has been criticized due to modeling errors, implausible assumption, insufficient power modeling and lack of transparency of the climate model used [144]. Specifically for storage, a limitation highlighted is that the model relies mainly on two technologies (underground thermal storage and phase change materials) that are very limited (0.0041 TWh for UTES) or in an early phase of development in the present and their massive deployment needed in such future scenarios could pose a challenge.

There have been some large scale projects proposed, aiming to expand the grid, which as already shown in Section 4, will decrease the storage need. Some of these initiatives are [145]:

- DESERTEC: Satisfy part of the European electricity demand with high interconnection to neighboring regions. This includes using the large solar potential in the MENA (Middle East and North Africa) area through laying 20 HVDC cables (5 GW each) across the Mediterranean Sea (200–500 km) and connection to the North Sea wind potential and Icelandic geothermal.
- NorNed: Connect the large hydropower in Norway to provide flexibility to the Dutch network as well as storage provision during periods of low demand. This is done through a 580-km (700 MW) subsea HVDC transmission
- The Gulf Cooperation Council Interconnection Authority (GCCIA):

[12] http://www.neocarbonenergy.fi.

Table 4
Potential of different alternatives to satisfy the global storage needs.

	Energy Density (kWh/m^3)	Local	Global	Notes
PHS	0.7	EU < 30 TWh (3400 TWh); US < 24 TWh (4200 TWh)	–	1. Numbers in parenthesis represent the power demand. 2. No study found on global potential
CAES	2.9	Northern Germany ~4.5 TWh (45 TWh)	~180–1800 TWh	[157] assesses the global potential, but no access to the report was possible
H_2 (underground)	190	Lower Saxony ~390 TWh, Northern Germany ~1614 TWh	~6400– 64,000 TWh	See Appendix B and Appendix C for more detail
H_2 (grid)	190	EU ~390 TWh (25% H_2 content)	Storage ~1200 TWh; 25% H_2 content ~3070 TWh (demand)	Global capacity if all current storage facilities are used 100% for hydrogen
CH_4	1000	Storage. EU ~1150 TWh, US ~1520 TWh	Storage ~4100 TWh	See Fig. 4 for comparison with demand
Liquid	9000	IEA countries ~7000 TWh (storage)	~ 12,000 TWh (existing storage)	See Appendix B
Heating	–	EU ~6400 TWh, US ~9000 TWh (demand)	~ 48,000 TWh (demand)	Heating represents almost 50% of energy demand [3]

Connecting the grids of six Arabian Gulf nations (Kuwait, Bahrain, Qatar, Saudi Arabia, United Arab Emirates, and Oman) in order to decrease costs, share capacity and decrease spinning reserve needs.

- The Trans-ASEAN[13] Electricity Grid: Connecting the grids (both gas and power) of the ASEAN states with a similar objective as the GCCIA.
- Pan-Asian grid connecting solar resources from Australia with wind resources from China. This would imply 590 GW of transmission over a distance of 10,000 km only to satisfy 17% of the electricity for Asia in 2050.

Even though some of the above initiatives are challenging, two of them (NorNed, GCCIA) have already become a reality and are proof that cooperation among different countries can occur for mutual benefit, providing more flexibility to the system.

There are already a set of studies looking at 100% RES systems. However, they have either limitations or different scope as the current review. A set of studies use EnergyPlan and H2RES[14] where both cover the entire energy system (i.e. including gas, heat and transport) and have been continuously used for assessing the feasibility of 100% RES systems [127,137,146–154]. A limitation of these studies is that they use a simulation approach, where the storage capacity might be part of the policies assumed and an input rather than a result of an optimization. Hence, the resulting storage size might be misleading and only those where an attempt to optimize the storage are included.

Similarly, two studies [155,156] already review 100% RES systems (23 and 24 publications respectively). Nevertheless, their scope is on electricity only and with attention to technologies, cost, models, coverage and comparison across studies in methodology rather than the focus on storage itself. Most of these studies were not included as part of the current review since they are either with simulation, statistical analysis, with limited set of flexibility options or without the cost component. Specifically for [156], only 7 out of 23 use an optimization approach and for [155], only 5 out of 24 were considered as part of this study, with the specific reason to discard the rest captured as a table in Appendix A.

6.3. Storage supply

This section aims to put in perspective the storage demand from the previous section (i.e. 600 TWh for < 95% RES and up to 2400 TWh for 100% RES systems) by comparing it with the potential of diverse options, these include the more established long term storage options (PHS, CAES), as well as the promising ones (H_2 underground storage and P2G) and the comparison with the demand size of other sectors to illustrate if a surplus in the power sector would be significant in those (since part of the flexibility can come from PtX rather than electricity storage only). Finally, power could be transformed to liquids (that have the highest energy density) and where already storage facilities (for oil and its derivatives) are already available and the same argument that for P2G could be used (that existing infrastructure can be exploited). The energy balance for the gas system is summarized in Fig. 4, in order to compare the storage demand with the gas storage facilities and gas demand values. The comparison with the potential for other alternatives is shown in Table 4, where more details on the assumptions and references can be found in Appendix B.

Based on the values in Fig. 6 and Table 4, some conclusions are:

- If P2G satisfies the storage need, 600 TWh of storage demand is to be compared with the numbers in the gas system. 600 TWh represents ~15% of current storage capacity (~10% of expected capacity by 2030 [158]), only ~1.6% of annual gas demand (< 1% of

[13] Association of Southeast Asian Nations.

[14] H2RES has a focus on hydrogen and has been applied mostly for isolated (island) systems.

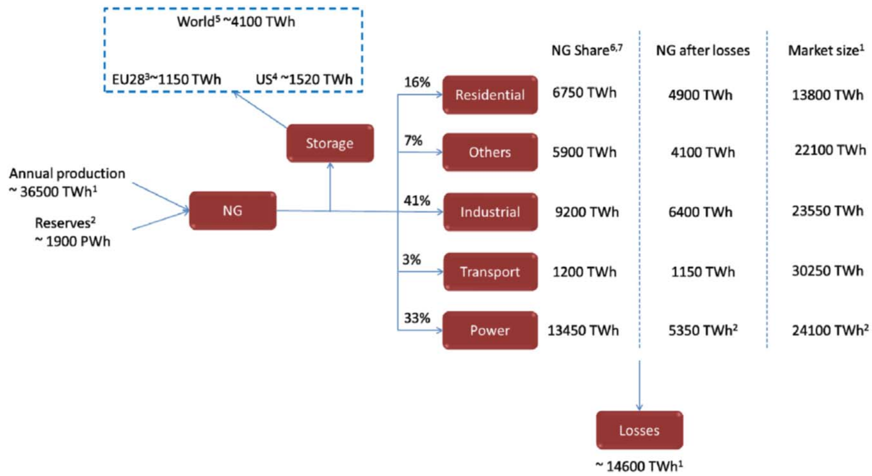

Fig. 6. Global natural gas annual energy flows, distribution among sectors and end-uses size. [1] EIA Outlook 2016. [2] BP 2016. [3] GSE Storage. [4] Weekly Working Gas in Underground Storage. [5] International Gas Union. WOC2 database, (Cedigaz, IHS Cera). [6] http://www.iea.org/sankey/#?c=World&s=Final consumption. [7] Numbers are before conversion losses, where the losses are ~40%, but differ per sector.

gas demand by 2040 [159]), ~12% of the current natural gas fraction in the power sector (~6% in 2040 [159]). In general, compared to the entire gas sector, the storage need is not so large.

- PHS is not enough to satisfy the storage need (see Appendix B) since its potential is at least one order of magnitude lower than needed and even without considering the location factor (that it is available in regions where it is needed).
- CAES could be a good candidate, but given the large number of sites and relatively low energy density (besides the technology de-risking required), there seems to be better options.
- In spite of the high uncertainty, the potential for H_2 underground is much larger than needed. Even injection to the grid with 15–20% H_2 content should be able to satisfy the need. However, temporal and spatial analysis of this concentration needs to be done.
- When looking broader than power, PtL could also use the existing facilities and the entire storage need would represent only 5% of the existing (storage) facilities for oil and derivatives. At the same time, since the heating demand represents ~50% of the entire primary energy demand, the storage need would only represent ~1.3% of the heating demand (favoring the use of Power to Heat technologies). In the future, this demand will decrease due to energy efficiency, but the cooling component will increase due to GDP growth in developing countries, urbanization and increased global temperature [160] leading to an even smaller fraction.

In general, P2G seems to be a promising option in terms of energy that can be stored and be able to satisfy the energy storage (or sink for the surplus) needed, since the storage need represents only a fraction of the already existing storage facilities. Nevertheless, PtL and use in heating represent better options (in terms of being able to absorb the surplus) with the disadvantage that the compensation can only be negative (i.e. deal with the power surplus, but not shortage).

7. Power-to-Gas

In the space of seasonal storage, the already deployed technology providing the closest service is PHS. However, as seen in the previous section, its potential is not be enough to cover the expected needs. P2G arises as a promising option to satisfy this requirement. In this section, an overview and classification of the studies done for P2G is done, in order to understand the areas that need more attention, as well as some conclusions from the existing literature. Then, some more attention is given to the system analyses being the focus of this study. For both cases, P2G is interpreted as having methane as product rather than hydrogen since this makes use of the existing facilities without modifications and avoids the more qualititative variable of risk (for operating facilities with a fraction of hydrogen) and spatial analysis (to calculate hydrogen concentration depending on where the surplus and demand are located).

P2G has a higher complexity (than PHS, CAES) due to the different choices in configuration, different markets that can serve and different services that can provide. Besides, the sizing of the components can be decoupled, with the electrolyzer, storage capacity and discharger having different capacity ratios. For a more detailed discussion on this, including the different value chains that can arise, refer to Appendix E.

7.1. P2G studies landscape

This section aims to look at the studies that have been done on P2G to understand better what its role is in future (high RES) scenarios. The literature on P2G is not as broad as Power to Hydrogen, mainly because the extra step resulting in lower efficiency and higher cost has caused that hydrogen is seen as a more (economically) feasible alternative and therefore with much more research on it. This provides an opportunity, that it is easier to have an overview of the different cluster of studies that have been done and understand how they complement each other. A total of 66 studies were collected, which are presented in Appendix G. The main criterion for selecting them was that power to methane specifically had to be explicitly considered and not just a generic storage with a default efficiency and cost or hydrogen only. The studies were seen to fall in these categories:

- LCOE [161–163]. Calculate the levelized cost for methane produced to compare it with a reference (natural gas, gasoline) or to assess the cost effect of design variables (efficiency, electricity price, operating hours) over the gas produced. Only some of these studies make use of the calculated levelized cost to further optimized the P2G capacity in the system.
- Process Design [164–167]. Calculate the optimal conditions for the

Table 5
RES penetration, scope and coverage of P2G studies.

	RES Management					Sectors included			Geographical Scale			
	RES Penetration (%)	Specific cost (€/kW)	P2G Efficiency[a]	Demand size (TWh)	P2G Size	Power	Gas	Mobility	Regional	National	Europe	Global
Plessmann 2014 [193]	100	940	50	28,600	1690 TWh	x	–	–	–	–	–	x
Moeller 2014 [108]	0–100	1880	49.2	22	0.184 TWh	x	–	–	x	–	–	–
Kotter 2015 [76]	100	900	60	4.5	0.7 TWh	x	x	–	x	–	–	–
Ahern 2015 [192]	38	–	55–80	68	0.6 TWh	x	x	–	–	x	–	–
Vandewalle 2015 [194]	75	800	65	218	5.43 TWh	x	x	–	–	x	–	–
Clegg 2015 [181]	15–30	–	47	1150	0.079 TWh	x	x	–	–	x	–	–
Jenstch 2014 [77]	85	750	62	1600	10 GW	x	x	–	–	x	–	–
ECN 2013 [190]	10–35	–	–	620	5.1 TWh	x	x	x	–	x	–	–
*LUT 2015 [74]	100	614	77	11,481	407.6 TWh	x	x		x	–	–	–
Schaber 2013 [44]	60–85	1100	57	2030	0–18	x	x	–	–	x	x	–
Henning 2015 [195]	52[b]	1100	61	1891	95 GW	x	x	x	–	x	–	–
Palzer 2014 [125]	70–100	1500	60	1385	78 TWh[c]	x	x	–	–	x	–	–
de Boer 2014 [99]	3–25	–	30.3	100	1–4 GW	x	–	–	–	x	–	–

[a] Reason for wide range is the conversion considered in each study. For some, the efficiency is Power to Methane, while for others in Power to Power.
[b] This considers the entire energy system, whereas power sector is covered 100% by RES.
[c] P2G has a power rating of 87 GW and an annual use of 224 TWh.

process, sizing equipment, making Capex and Opex calculation. The control volume for these studies is usually at the plant level and not systems level. A limitation arising from this is that variability in time, type of services that can be provided, market assessment, value chains are not considered.

- Time series [99,168–170]. These do look at the profiles for supply and demand and intervals where P2G can be attractive, aiming to use the power surplus that otherwise would be curtailed. Nevertheless, plant capacity is not optimized based on cost, operating hours (trade-off), uncertainty in forecasts, but instead just looking at possible higher RES integration (only benefit).
- Potential [171–174]. Discuss the role that P2G can play in the respective regions/countries with quantification of (either) CO_2 sources, energy rating, power rating, fraction of mobility. A limitation of these is usually that capacities are not the result of cost effective comparison with other flexibility alternatives.
- Business model [175,176]. Usually with the perspective of an investor, using an electricity curve and assessing the value of storage for price arbitrage, balancing, reserves market or gas production. These use perfect foresight and neglect the effect of storage on electricity price, both of which can lead to a higher revenue than what could be obtained in reality.
- Technology Review [11,177–180]. Discuss possibilities for technologies in electrolysis, methanation, storage, reactor design, materials, learning curves and expectations for the future.
- Cost optimization [77,108,181,182]. Power or energy models to compare P2G with other options and determine if it is part of the cost optimal solution. Capacity is usually exogenous for power models (operational), while it is an output of energy models (investment planning).
- LCA [183–185]. Make the comparison of the methane produced with other reference processes or compounds depending on the final use.
- Projects Survey [172,186]. Aim to complete the list of existing demo plants in different regions.

From these, some conclusions are:

- The most explored areas seem to be LCOE (due to the unfavorable economics and multiple assessments on what price range and operating costs can be expected in the future), potential and cost optimization (aiming to understand what role it can play in the future when compared with other flexibility options).
- The least explored areas are LCA (where there are only three studies [184,185,187] that address P2G in a more generic way rather than for a specific application or sector, even though there are references that include methane, but not necessarily from P2G), business model (where only [175] focuses on both P2G and detailed NPV assessment with a Monte Carlo approach and configurations, other studies [178,188] do cover part of the NPV as part of the LCOE calculation) and time series (which is understandable since it is a limited approach where only operating hours and residual curves are used, which might not lead to the optimized capacity).
- The study that covers the most areas from the ones mapped is [172], where a thorough review was done with focus on Austria. It covers the integration with the rest of the system, potential applications, macro-economic, environmental and regulatory factors. [179] also makes a meta-review on different studies at a country level, extends on the necessary effort for research and development, regulatory framework besides economic and environmental performance. A couple from the Germany community [171,173,189] and one for the Netherlands [190], where P2G (specifically to methane) was not arising as promising option in spite of different CO_2 and technology restrictions being used.
- The high energy consumption nature of the process is highlighted in some cases. For example [183], the CO_2 sources in Austria are surveyed to identify their possible use for P2G. The survey is done considering net emissions, capture efficiency, energy penalty introduced in the process due to capture, number of installations and proximity to wind parks. If all the emitted CO_2 is converted to methane, the energy consumption would be around 185 TWh. To put this in perspective, for 2013, 9.3 TWh were generated by PV and

Table 6
Flexibility options and features included in P2G studies.

	Flexibility Options							
	Flexible generation	Transmission network	DSM	Demand elasticity	Optimal wind/PV	Power to Heat	Short-term storage	Thermal storage
Plessmann 2014 [193]	-	-	-	-	x	-	x	x
Moeller 2014 [108]	-	x	-	-	x	-	x	-
Kotter 2015 [76]	-	-	-	-	x	x	x	-
Ahern 2015 [192]	-	x	-	-	-	-	-	-
Vandewalle 2015 [194]	-	-	-	-	-	-	-	-
Clegg 2015 [181]	-	x	-	-	-	-	-	-
Jenstch 2014 [77]	x	x	x	-	x	x	x	-
ECN 2013 [190]	x	x	x	-	x	-	x	-
*LUT 2015 [74]	x	x	-	-	x	x	x	x
Schaber 2013 [44]	-	x	-	-	x	x	-	-
Henning 2015 [195]	-	-	-	-	x	x	-	x
Palzer 2014 [125]	x	-	-	-	x	x	x	x
de Boer 2014 [99]	-	-	-	-	-	-	-	-

	Sensitivities[a]							Features[b]							
	Capex	Efficiency	CO_2 / RES Target	Fuel Prices	Technology Portfolio	H_2 in Grid	H_2 in Transport	Operational	Investment	Gas Network	Cost learning curve	Endogenous electricity price	Hydrogen only	CO_2 sources	Energy efficiency
Plessmann 2014 [193]	-	-	-	-	-	-	-	x	x	-	-	-	-	-	-
Moeller 2014 [108]	-	-	x	-	-	-	-	x	x	-	x	-	-	-	-
Kotter 2015 [76]	x	-	-	-	x	-	-	x	x	-	x	-	-	x	-
Ahern 2015 [192]	-	-	-	-	-	-	-	x	-	-	-	-	-	x	-
Vandewalle 2015 [194]	-	-	x	-	-	-	-	x	-	-	-	x	-	-	-
Clegg 2015 [181]	-	-	x	-	-	x	-	x	-	x	-	x	x	-	-
Jenstch 2014 [77]	x	-	-	-	-	-	-	x	-	-	x	x	-	-	-
ECN 2013 [190]	x	-	x	x	x	x	x	-	x	-	x	x	x	-	-
*LUT 2015 [74]	-	-	-	-	-	-	-	-	x	-	-	x	-	-	-
Schaber 2013 [44]	x	-	x	x	x	-	-	x	x	-	-	x	x	-	-
Henning 2015 [195]	-	-	x	-	-	-	x	-	x	-	x	-	-	-	-
Palzer 2014 [125]	-	-	-	-	-	-	-	x	x	-	-	-	-	-	x
de Boer 2014 [99]	-	-	x	-	-	-	-	x	-	-	-	-	-	-	-

[a] "Capex" and "efficiency" assumptions changed to evaluate effect on size/system. "Technology Portfolio" refers to limiting technologies available (e.g. CCS) to evaluate impact on P2G

[b] "Gas Network" refers to having an explicit representation of the gas network (i.e. pipelines). "Hydrogen only" refers to the possibility of having H_2 as a separate product (not only the possibility of methane). "Energy efficiency" refers to reducing the energy demand and evaluating the effect on P2G

wind in Austria and the average power consumption for the country is ~65 TWh. This implies that P2G needs additional installed capacity rather than operating only with power surplus, which is negative in several ways, additional investment needed for generation, higher average electricity price and that a fraction of the time it operates with power from the grid increasing the LCA emissions. A further comparison could be done with the hydrogen demand as chemical feedstock. If all this demand would be satisfied with electrolysis, the power input needed would be 3200–5400 TWh [184].
- Sites potential. Most of the studies deal with P2G in terms of efficiency, cost, power surplus and mass balance. However, it should be noted that once these quantities are related to specific locations constraints related to: proximity to the natural gas grid, to VRE sources, minimum plant size, restrictive areas (e.g. nature protection), among others, have to be considered. In [191], 65% of the CO_2 (95% of it originating from biogas plants) could not be used due to these constraints.

Since, the focus of this study is a system analysis perspective, a more detailed look at this type follows in the next section.

7.2. P2G – A system analysis

From the previous set of studies, 23 of them were selected for further analysis. The criteria for this selection were:

- P2G capacity had to be the result of cost optimization (to understand its role in an optimal mix).
- One study [192] has an exogenous defined capacity (exception to rule above), but was included for the insight of the operational performance of P2G. An hourly resolution model with operational constraints and integer component is used. [97] has a similar approach, but considers only hydrogen (and not methane) and therefore, was not included.
- P2G specifically with methane as product (also with H_2+CH_4 possibility, but not H_2 only).
- Approach with the energy system, different flexibility options and time aggregation or hourly simulation over a year. Therefore, studies like [64,104,162,188] that look either only at levelized cost of electricity in isolation or have limited competition with other flexibility options were not included.
- Language: English.

The characterization of the studies is shown in Table 5. Furthermore, since P2G competes with other flexibility options is important to specify what options were considered in the different studies (Table 6) to know if P2G arises because of limited technologies available. 11 of the studies come from the same project (Neo Carbon project), use the same model, with the same approach and assumptions. Therefore, these have been included only once in both Tables (identified with "*").

Comments around the studies are divided in two main categories: (1) non-technical, addressing coverage of the studies and areas that have not been explored (2) technical, aiming to understand better the role, size for P2G and comparison with other integration measures.

In terms of sectoral coverage, 9 of the studies do consider more than the power network and take into account that the gas can be used for the heating, industrial sector as part of the gas network. Only 2 include the mobility sector as one possible final use for the product. Nevertheless, in [190] this option only arises when CCS and nuclear are not part of the technology portfolio. However, hydrogen is the end product rather than methane.

Most of the studies are on the national level, with 4 of them focusing on Germany. Only one [193] has a global scale, while it has the advantages of considering over 160 countries with a high spatial (1° × 1° latitude x longitude) and temporal (1 year with hourly steps) resolution, splitting the storage in short-term, P2G and thermal and using a 100% RES system,[15] it has the limitations that it does not consider other sectors or flexibility options, there is no energy exchange between adjacent networks (copper plate between regions, but no connected regions more than 100 km apart) and neglects hydro and biomass potential.

With respect to technical conclusions, the main ones are captured below:

- Mobility sector. Some mixed conclusions are obtained. From [195], P2G is an enabling technology that allows achieving RES penetrations higher than 82%. Even though above such percentage, most of the transport (60%) is with electricity and only ~20% with hybrid gas-battery, P2G has to be part of the mix since its absence causes non-feasibility of the scenarios. For the boundary value of 82%, P2G leads to a total system cost reduction of 25% compared to a scenario where the technology is not available. P2G capacity is ~140 GW compared to ~550 GW for wind and solar, where most of it is actually methanation rather than hydrogen. This could also be because both wind and solar reach their maximum potential and to increase their share or having lower footprint a better use of the already produced energy has to be implemented (i.e. with a more optimistic potential for wind and solar, the model could deploy more of these decreasing the need for P2G). On the other hand, in [190], sensitivities were done for specific Capex for the electrolyzer, CO_2 reduction target (up to 85%), targets for wind and solar capacity (affecting the variability), fuel prices, technology restrictions (CCS, nuclear and biomass), lower investment cost for H_2 transport application and variable H_2 content in the natural gas grid. From all these, only when the potential for CCS and biomass is limited or when the limit for the hydrogen content in the gas network is too low, some of the product is absorbed by the transport sector. For this case, not methane, but hydrogen is the final product, while the electrolyzer becomes significant in size (19 GW) with respect to the rest of the system (~30 GW).
- P2G role. The largest contribution is in [193], where it represents one quarter of the total annual energy exchanged by electricity storage and almost 6% of the total annual generated electricity. However, given the limitations mentioned earlier in this section, this only provides an upper value that will become more realistic once flexibility options (and other sectors) are considered. In [76], the P2G role is also significant, representing almost 25% of the annual electricity demand (although no mention is made to installed energy capacity[16]). However, this study deals with covering 100% of the electricity with RES and using the surplus for the heating sector. Hence, Power-to-Heat is used when there is co-occurrence between power surplus and heating demand and the rest being used for P2G. Curtailment is minimal, being only significant when PtH is not available. The constant portion of the energy produced by the system is the electricity fraction, with the total varying per case depending on the amount absorbed by P2G, PtH and curtailed. In [125], P2G energy capacity represents almost 6% of the annual demand with the total energy exchanged in a year about 18%. However, sources of flexibility in generation come from combined cycle using gas from P2G and there is no hydro or biomass that could provide additional flexibility. Furthermore, there is no interconnection consideration or DSM which could alleviate the short term fluctuations and avoid the need of the surplus being diversified to gas or heat.

[15] Note that this study was not considered in Table 3 because given the limited choices for flexibility, it resulted in 65% of the energy produced not being used immediately, increasing the need for storage to 25% of the demand on annual basis and 6% on a single cycle (installed capacity), which from other studies seem to be a result of the limited number of choices.

[16] Installed power capacity is 218MW, compared to an average demand of 328MW.

- Seasonality use. In [193], the total storage capacity is equivalent to 30 days of continuous discharge (but only 22 days of daily demand) and has an annual use of 1.2 cycles. The largest storage is thermal, the ratio between annual use and capacity (4800 TWh vs. 73.6 TWh) leads to 65 full cycles in a year, which seems to indicate thermal storage is not for seasonal use. This is different from [125], where thermal plays the major role in seasonal storage in combination with CHP operation and has almost three times the P2G capacity. For most of the LUT studies, P2G has < 0.4 cycles a year, being used as seasonal storage when the demand is expanded to the industrial gas and around 1.5–2.2 cycles when only the power sector is considered.
- Cost impact. The absence of P2G in the technology portfolio can lead to an increase in system cost for a high RES penetration. For [76], the total cost increased by 10% when P2G was absent. In [181], the focus is on operational costs rather than total (considering investment), but these are reduced by 4–9% depending on the level of penetration (15–30%). In [74], using P2G to satisfy the industrial demand, actually results in an electricity price increase of almost 30%.
- Effect of cost learning curve over P2G role. In [76], a base cost of 900 €/kW is used with the sensitivity being up to 2500 €/kW. Up to 1800 €/kW, there is a marginal change in capacity and full load hours, but it does increase the system cost by ~7%. For 2500 €/kW, P2G role is greatly (by ~60–70%) diminished, being partially replaced by Power-to-Heat and batteries and resulting in a system cost increase of almost 10%.
- Effect on gas grid. In [181], the introduction of P2G with an equivalent capacity of one third of the total installed capacity led to a reduction of 3–8% of the seasonal storage, given that part of the gas demand is covered by P2G. Furthermore, P2G covering part of the gas demand also reduces the seasonal gas price spread by 4–16%.[17] [182] makes the explicit split between the effects over the electricity and the gas network. For the gas network, there is a marginal effect over gas imports in the long term, with the largest difference being for RES integration rather than P2G. Gas flexibility (defined as additional gas needed due to the use of gas turbines to balance wind fluctuations) is around 12% higher with P2G. In the shorter term, there could be situations where the gas demand is low or even absent and all the gas being consumed has been generated by P2G. For these cases, marginal costs of P2G would be dictating the gas price rather than imported or produced gas. Market should be adjusted to deal with these periods of time.
- Sensitivities. One of the most complete studies is [190] that uses an energy model and is focused around P2G. In none of the sensitivities P2G was necessary (only Power to Hydrogen, but not methane, using the H_2 mainly for transport). Some of the studies have limited sensitivities on P2G for two main reasons: focus on the rest of the system (and variations are in Capex for generation or RES penetration with P2G as resultant value) or focus on operational component and analysis of hourly values (e.g. power surplus, electricity price). [77,192,194] use an operational model where the capacity installed is an input and the sensitivities were limited. Most of the models focus on the power network or P2G to absorb the power surplus. There is limited insight on the competition with hydrogen and its use for either mobility or injection in the gas grid ([181] explores injection, but does not include mobility). The variation of efficiency (that can be achieved through heat integration) was not explored by any of the studies.

8. Conclusions

Some key conclusions from above analysis are:

- The consideration of multiple flexibility options (from network expansion, storage, wind/solar ratio, flexible generation, excess of capacity, DSM and curtailment) have synergistic and complementary effects. Estimates of 2 months equivalent of demand as storage or 10 times grid expansion (with respect to current state) can be greatly reduced by including more of these alternatives to deal with the variability and power surplus.
- Including sectors other than power (Power to X including fuels, heat and gas) in the analyzed scope can be beneficial (i.e. lower overall cost and lower energy curtailment) since more options are available for flexibility and result in lower storage needs compared to systems covering power only.
- There is a trade-off between number of flexibility options and model complexity (and resulting calculation time) that lead to making compromises in the choice of modeling approach and elements included. From the current review, some of these choices are: sectors covered (power vs. heat and mobility), use of operational constraints vs. investment planning, use of integers for individual plants vs. aggregation by plant type, time resolution (hourly vs. representative), transmission network (copper plate vs. tranmission and distribution), centralized optimization (vs. several players maximizing their utility), uncertainty analysis (deterministic vs. stochastic).
- The role of storage becomes more relevant for high VRE penetrations. Below 30% penetration, curtailment is usually the best option, since the number of hours when there is a surplus is not enough to justify an investment. To reach fractions > 80%, storage (and specifically long-term) plays a key role and reduces the overall system cost (compared to a system without storage). However, most of the storage need is for daily fluctuations, where further additions of capacity have diminishing marginal added value.
- The power storage needs for electricity systems with less than 95% penetration are at most 1.5% of equivalent annual demand in terms of energy rating. Considering future global electricity demand, this storage need might be in the order of 600 TWh. The PHS potential is not enough to satisfy such need, but seems to be enough to support the transition period. CAES has a much larger potential and more suitable locations around the world. However, it is still limited compared to chemical storage. Only 2% of the global annual natural gas production or 10% of the gas storage facilities would be enough to cover such need.
- Another alternative to deal with the power surplus is the conversion to liquids (PtL). The storage need would only represent 2% of the transport demand and ~5% of the storage capacity. An advantage is that liquid fuels have the highest volumetric energy density. The main disadvantage of this option is that it would only provide negative reserve, being more difficult to cover power shortages when needed.
- In 100% RES scenarios for entire energy system, the energy storage demand seems to be higher than 1.5%.[18] The upper bound remains unclear since high estimates were obtained from studies with limited number of flexibility options. Most of the studies remain below 6%. Sources of flexibility for these scenarios can be CCGT with green gas, biomass CHP, thermal storage, PtL or Power to Heat.
- Seasonal storage function can sometimes also be provided by thermal storage, either through heat pumps or storage associated to CSP.
- Efficiency is key for storage, where lower efficiencies will translate

[17] Upper values represent a higher VRE penetration with wind and solar production being almost doubled.

[18] This fraction refers to the energy storage capacity (e.g. TWh) compared to the total energy demand for the system.

into either extra generation capacity to satisfy the demand or extra storage capacity to satisfy a need from the system. In both cases, this translates into additional investment. It plays a more important role for short-term applications (balancing) and with larger quantities of storage deployed.

- Power to Gas has the main advantage of being able to produce different compounds and for different sectors. This gives more robustness to the technology as it provides more revenue streams.
- Due to the high technology cost, one option for P2G is to increase the size of the facilities to benefit from economies of scale. The amount of power needed for such plants places uncertainty over the fact that plants will only operate when there is power surplus from RES (otherwise the CO_2 footprint of the methane produced is in most cases higher than conventional NG). A further complication can be the sources for CO_2 (in the required quantities and location) which will directly impact the LCA footprint of the system.
- P2G is to be seen as an option to deal with the power surplus rather than a technology to satisfy the current gas demand in a sustainable way. The reason for this is that due to its low efficiency and relative sizes of the electricity and gas sectors, satisfying the gas demand with P2G would require at least three times the current power installed capacity, representing a large cost and providing a large budget that could be used another way to fulfill the same purpose.
- The most explored area for P2G is the techno-economic evaluation and effect of different variables over production cost. This is logical given the difficult justification of the technology based on monetary terms. Least explored areas remain to be LCA.
- Few studies have focused specifically on P2G from an energy modeling perspective. Most of the studies so far have included P2G as part of the technology portfolio, but attention has been given to the rest of the system and its evolution in the path to decarbonization.

Next steps are:

- Choose a specific system to analyze the trade-offs between flexibility options with a fixed set of assumptions and understand how leaving some of them out can affect the results and the calculation time. This should include the entire energy system (not only power) to include the various technology vectors. An outcome can be the identification of the marginal technology that is attractive with additional RES capacity.
- Choose a specific system to analyze the P2G role, considering the entire energy system, looking at its contribution as the RES fraction becomes higher, competition with other storage and flexibility options, with a cost optimization approach including the investment component, with sensitivities for cost and efficiency and capturing better the environmental effect of the CO_2 use.
- Analyses done with cost optimization should be expanded to capture storage effect over electricity price, where its introduction in the system will cause lower price spikes and higher minimum prices, reducing the incentive for storage as more of it is installed.
- For a complete storage analysis, the interaction between power, energy, macro-economy and market components should be captured. Power allows capturing the dynamics and operational constraints, energy since all the networks and technology vectors should be included, macro-economy to capture demand variations with price and cost elasticity and market to reproduce the presence of different players with different interests that deviate the solution from a central optimization approach.
- This study has put in perspective the amount of storage needed and its comparison with the possible alternatives to satisfy it. A next step is to carry out a geographical match between storage demand and alternatives for it, as local conditions will change the outcome.
- Look into the LCA component of P2G and all the possible value chains that can arise to systematically compare them and analyze their footprint, since this area still remains partially covered.

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Appendix A. 100% RES studies reviewed by [155] and consideration for this study

Author	Original Reference from [155]	Included in this study	Justification
Mason	[9,104]	N	Simulation, no cost consideration, only PHS as storage
Australian Energy Market Operator	[8]	Y	
Australian Energy Market Operator	[8]	Y	
Jacobson	[112]	N	Limited technology portfolio. Relies on very large deployment of a technology not used in the present
Wright and Hearps	[60]	N	No mention to storage other than PHS and CSP thermal storage. Focus only on power
Fthenakis	[133]	N	Based on feasibility, potential and input from other studies rather than cost optimization
Allen	[27]	Y	
Connolly	[19]	Y	
Fernandes and Ferreira	[119]	N	Simulation, no clear criterion for selection of storage size of 3000 MW
Krajacic	[20]	N	Simulation
Esteban	[17]	Y	Not cost optimization, but storage optimized based on wind/solar ratio
Budischak	[118]	N	Only for interaction with other variables, but not for optimized sizes
Elliston	[22]	N	Cost optimization, but no mention to storage other than CSP with 2.5 and 15 h
Lund and Mathiesen	[16]	N	Simulation, no mention to storage
Cosic	[11]	N	Simulation, no mention to storage
Elliston	[75]	N	
Jacobson	[18]	N	Limited technology portfolio. Relies on very large deployment of a technology not used in the present
Price Waterhouse Coopers	[10]	N	
European Renewable Energy Council	[26]	N	No specific sizes and energy delivered by storage and only reference to thermal storage as part of CSP
Climate Works	[116]	N	No specific sizes and energy delivered by storage and only reference to PHS
World Wildlife Fund	[108]	N	No specific sizes and energy delivered by storage and only reference to thermal storage as part of CSP
Jacobson and Delucchi	[24,25]	N	Limited technology portfolio. Relies on very large deployment of a technology not used in the present
Jacobson	[113]	N	Limited technology portfolio. Relies on very large deployment of a technology not used in the present
Greenpeace	[15]	N	Storage is minimized as it is expected that costs will not decrease enough in the study time frame

Appendix B. Potential of different alternatives to satisfy the storage needs

Natural gas underground gas storage facilities

There are a total of 688 natural gas storage facilities worldwide as of January 2013, with a combined working gas capacity of 377 billion m^3 (bcm),[19] which represents ~10% of the world consumption [196]. This quantity is expected to increase to 580–630 bcm by 2030, leading to a similar fraction of gas demand and needing ~120 bln€ investment, with most (60%) of the growth in Asia [158]. Around three quarters of these facilities are depleted fields and only 14% are salt caverns.

The 600 TWh of storage needed would represent around 15% of the working capacity for the existing underground natural gas storage around the world. However, this would be comparing existing facilities vs. future energy demand (i.e. assuming no facilities are constructed or de-commissioned). This would decrease to ~10% of the storage capacity with the extensions considered in the future. Comparing the storage need with the natural gas production (rather than storage only), it represents almost 2% of the entire natural gas production in a year (being smaller in the future with larger NG production).

Heating demand

A common business case proposed for P2G is to store the power surplus in summer and use it in winter for heating, which is applicable for most countries in Europe. Heating represents almost 50% of the final energy demand in EU. This heating demand is in turn split in ~45% for the residential sector, ~40% industry and 15% tertiary sector.[20] The end use varies from 94% of the residential demand being for space and water

[19] Number corresponds to working gas capacity which already discounts the cushion gas volume.
[20] The specific split per country can vary depending on its specific energy mix.

heating to 82% being used for process heating in industry. However, natural gas only represents ~45% of the energy mix for this sector. Hence, the entire energy demand for EU (12,800 TWh) is reduced to 6400 TWh for heating specifically and further to 2850 TWh for the gas fraction in the heating demand [197]. However, the natural gas fraction can greatly vary per country, providing up to 50% in UK and as little as 5% in Sweden [198]. Therefore, even with the seasonal component of heating demand (where the ratio between minimum and maximum over a year can be 1:10 [198]), there will always be a fraction of heating that needs to be satisfied. Since the heating sector is larger than power for the largest energy consumers in Europe. A surplus in the power sector represents roughly half of the relative contribution in the heating sector (i.e. heating demand for EU28 is ~6250 TWh [198], while the power demand is ~3000 TWh [Eurostat] with the breakdown per country in Appendix D). The other variable to consider is the occurrence in time for these events. There has to be a coincident surplus of power with a heat demand. Otherwise, these could be partially shifted in time with (thermal) storage. This has been considered in [199] for Germany.

Looking at the longer term and global scale, heating demand in the residential sector is expected to decrease by 34% in 2100 and actually is the cooling component acquiring more relevance by increasing by 72% (mostly in Asia) [160]. The higher temperatures due to climate change can even increase further this cooling demand by 50% [200]. Hence, the higher cooling demand in current developing countries due to higher electricity penetration and GDP growth combined with the decrease in heating demand could change the relation between both from 95/5 (heating/cooling) today to 30/70 in 2100 [160]. Furthermore, it is expected that the natural gas and coal fraction used in heating will decrease, with a larger role for electricity [200] and the use of heat pumps. Nevertheless, it has to be noted that these numbers carry high uncertainty associated to fuel prices, GDP, population growth, energy efficiency measures and actual feedback from changes in temperature due to climate change, but it puts in perspective both the storage need compared to the demand, but also the use of the produced gas through P2G for heating (which seems more applicable to an European framework).

Other large scale storage alternative - PHS

This is the first logical choice due to its maturity, relative high efficiency, low energy based cost, long lifetime, large power capacity and dominant role in power storage (130 GW of installed capacity, being ~99% of the total installed capacity).

Its realizable potential in Europe, from an initial assessment [201], was identified as 29 TWh if the reservoirs are within 20 km from each other, reduced to only 0.2 TWh if 5 km are considered. These values correspond to reservoirs that are already existing within those distances and applying constraints of population, natural areas, infrastructure. If the conditions are relaxed to only one existing reservoir, the potentials increase to 80 and 10 TWh respectively. Additional restrictions might be required (e.g. drinking water, supply water, might be too expensive to build) to have the actual potential.

Another reference for Europe[21] is the eStorage project, which was a follow-up of [201] and where more conservative estimates were obtained [9]. The potential was 2.3 TWh, distributed in 117 sites, with 54% of such capacity being in Norway and 13% in the Alps. This number was identified as the total realizable potential vs. a theoretical maximum of 6.9 TWh (and 714 sites). A difference with [201] is that due to the varying restriction for granting permissions and different legislations in each country, national experts were involved to make a judgment on the results obtained during a first phase of GIS. The other major difference is the distribution of the potential, while [201] allocated two thirds of the potential to Turkey, the eStorage project estimated that over 60% is in Norway.

As reference the power demand for Europe is around 3400 TWh. The problem with this alternative is the geographical location for these sites is not flexible, the number of plants to be constructed would be more than 1000, which would be material intensive and could have an effect on the local environment, besides the fact that currently PHS is only used up to 12 h with few applications for a longer period than a couple of days. Hence, not solving the problem of seasonal storage. A final problem with PHS is that due to climate change effects, higher average temperatures and river flow patterns, the potential for PHS will be reduced (in Europe) and the lower availability of water for power production might lead to higher electricity prices of up to 30% in some countries [202] and the water consumption is much higher than other technologies because of higher evaporation rates due to the exposed surface area. Increasing pressure on water availability in the years to come, higher water footprint is not desirable.

Looking at other regions in the world, in US, PHS development slowed down in the late 1980s, and there has not been recent estimates of the maximum potential that it can achieve [203]. The best estimate is [204], where almost 1000 GW of capacity were identified across the US. Assuming a 24-h storage capacity (as an optimistic assumption), this would lead to 24 TWh compared to a power demand for US of 4200 TWh and of ~ 25,000 TWh for 2040 as total primary energy supply [3].

No single report was found assessing the global potential for PHS. IEA estimates the expected range of capacities for 2050 to be between 412 and 700 GW [205]. Assuming a 24-h energy rating, this would be equivalent to 10–16.8 TWh of storage capacity. Around one quarter of this capacity is expected in China, another quarter in Europe and ~20% in US. For this case, it seems the realizable potential (at least in Europe and US) is not being exploited to its maximum. Such capacity does not seem to be enough to satisfy the needs of high RES penetration, although it does seem to satisfy the expected storage needs expected by then (190–310 GW as highlighted before) by IEA estimates as well [49].

Other large scale storage alternative - CAES

CAES would have the advantage of being able to store more energy per m^3, being ~4x the PHS value (~2.9 kWh/m^3 vs. 0.7 kWh/m^3).[22] The other main advantage is that even though there is dependence from geological characteristics of the ground, there are many more suitable locations for underground CAES than PHS. Some disadvantages for the technology are the maturity level, depending on the variation used, some additional gas input might be needed for heating the air before expansion and that the storage needs to stay within a specified pressure range limiting its operation and introducing a dead volume that cannot be used (i.e. cushion gas).

Salt caverns represent only 14% of the current (gas) storage facilities, but are the best option for CAES (and H_2) given their flexibility (having higher withdrawal and injection rates), lower share of cushion gas required and ability to handle more frequent cycles, which is desired in case these facilities want to be used for short-term balancing as well. The other main reason to target salt caverns is their non-porous nature. This prevents the oxygen (or the hydrogen) from migrating through the pores and reacting with minerals and microorganisms, which can cause losses and undesired by-products.

There are two further limitations for CAES. One is that sufficient fresh water has to be available in the vicinity of the facility for the solution mining process. Furthermore, it has to be close to the sea to dispose the brine produced or close to an industrial site that can use it as raw material.

[21] EU-15 plus Norway and Switzerland.

[22] 2MPa pressure for CAES and 300m differential head for PHS.

The other one is that the depth window for these caverns is between 500 and 1300 m, because the operating pressure is directly dependent on the depth, and the power plant components using current state of the art technology operate at pressures between 50 and 100 bar. This is less flexible that hydrogen caverns that can be anywhere between 400 and 2400 m [206].

The global geological data for salt deposits has been assessed before [157] with figures for Europe and the world in Appendix C. Unfortunately, access to the full report with volume and potential figures is not available. Instead some specific information for Germany is available that shows the energy potential that can be stored. In Lower Saxony, 568 salt caverns were identified with a volume of ~170 mln m^3, equivalent to 0.37 TWh (adiabatic) [207]. On a national level, there is the InSpEE project[23] funded by the energy storage initiative of the German Federal Ministries of Economy and Energy (BMWi) to look specifically at the potential of salt caverns for energy storage and was completed in 2015. 269 salt structures were classified as having potential and 2D/3D visualizations were developed for these structures. Using geological structural considerations and GIS-based modeling, a more detailed assessment than previous studies was done. As outcome, the potential in Northern Germany was identified as 4.5 TWh for CAES [208]. Status of the technology, outlook, upcoming projects, development and targets for research have been left out of this review to keep it focused on the energy comparison with the other technologies. For such topics, the reader is referred to [209,210].

Other large scale storage alternative – Underground H_2

A parallel result of these two studies in Germany was the potential for H_2 storage since they also use salt caverns as potential sites. In Lower Saxony, 2320 suitable salt caverns were identified with a total volume of 1160 m^3 equivalent to ~390 TWh [207], while for (Northern) Germany, such potential was 1614 TWh [208]. To put these numbers in perspective, the electricity demand for Lower Saxony is ~45 TWh (pro-rated based on population), while for the entire Germany is ~510 TWh. The heating sector is ~1000 TWh and the entire total energy consumption is ~2520 TWh. Therefore, the numbers for CAES are < 1% of the power demand, while the figures for H_2 capacity are significant, being even 3x larger (only Northern Germany) than the entire current power demand in a year.

For the quantification of the global capacities for salt caverns, [157] does make such global assessment. However, the report is part of the SMRI library only accessible to members. Staff were contacted, but the key value of salt caverns volume was unfortunately not given. An alternative calculation method to estimate this value is to use the potential for CCS since saline formations are one of the potential options (along with depleted oil and gas fields). [211] estimates the global capacity at 1000– 10,000 $GtCO_2$. For US, the Department of Energy has estimated the capacity to be 2400– 21,600 $GtCO_2$ (medium estimate of 8300 $GtCO_2$). For Europe, an estimate is ~250 $GtCO_2$ [212], where around 10% is located in Germany. Therefore, assuming that the saline aquifer potential in Northern Germany is the one available for the entire country (i.e. conservative), the potential storage in Europe could be in the order of 16,000 TWh of hydrogen and a global capacity 4-40x higher at 64,000– 40,000 TWh of capacity. Even the conservative estimate (only 4x) would translate into a storage capacity much larger than the expected future total electricity demand. Consequently, if saline formations are used for underground hydrogen storage, the global capacity should be more than enough to satisfy the system needs. A remaining disadvantage is that all this potential is split in many small caverns. To avoid constructing a very large number of facilities, a minimum size would have to be defined, limiting the specific sites that can be used.

The above numbers highlight one of the main advantages for hydrogen, which is the energy is stored in the chemical bonds of the compounds rather than as mechanical energy. This increases by almost two orders of magnitude the energy that can be stored per m^3. If an ideal hydrogen storage is considered, the energy that can be stored is ~310 kWh/m^3. Since it is not ideal, less energy is delivered out of the storage with respect to the energy input. Considering an efficiency of 60%, the energy density for hydrogen decreases to ~190 kWh/m^3. Still much higher than the equivalent for the mechanical counterparts (0.7–2.9 kWh/m^3). A common size for a cavern is 500,000 m^3, which has a net storage capacity of ~4 k ton of H_2 or ~0.15 TWh [213].

Nevertheless, a disadvantage for H_2 is the low volumetric energy density (12.75 MJ/m^3 vs. ~35–40 MJ/m^3 for methane for example) in spite of having a high mass density (120 MJ/kg vs. 50 MJ/kg for methane). Another one is that the compressibility factor of hydrogen is > 1 (1.05 at 10 MPa and 365 K), which introduces further difference with methane (Z = 0.94 at same conditions). These two factors reduce the amount of energy that can be stored as hydrogen in case facilities for natural gas are being used. Therefore, if all the natural gas storage facilities were used for hydrogen, the energy would be ~1200 TWh instead of 4100 TWh equivalent of NG. However, this would assume 100% H_2 content in the underground storage which might not be feasible in the short-term and also includes porous formations that have higher uncertainty than salt caverns due to its gas tightness. For H_2, salt caverns are the preferred option, followed by depleted gas fields and aquifers, while rock caverns and depleted oil fields have higher uncertainties associated [214]. There might be locations (e.g. Texas, France, Denmark), where no suitable salt deposits are available and porous rock can be considered [206]. That would expand even further the potential for both CAES and H_2. There are already a few examples where hydrogen has been stored underground at large scale. One example is in Clemens Terminal in Texas, operated by ConocoPhillips, with a storage capacity of 2520 metric tons [215] (only ~0.1 TWh). Another one in Teesside, England, where the British ICI company has stored 1 mln Nm^3 (3.5 GWh) in 3 salt caverns of around 400 m. Another one in France, where the gas company Gaz, has stored 50–60% hydrogen in an aquifer of 330 mln Nm^3 for over 20 years [216].

In general it can be safely assumed that in case this is the selected alternative for large scale storage, most of the facilities would need to be constructed. Nevertheless, the storage component is usually relatively small (< 5%) fraction of the hydrogen production cost, compared to the Capex for the electrolyzer and the Opex for the electricity input [213]. A typical specific price for the cavern is 60 €/m^3 [213], with the typical size of 0.5 mln m^3 would result in 30 M€ (excluding the cushion gas volume). This is equivalent to 0.2 €/kWh (0.15 TWh of energy rating), which is on the low side of energy cost for the technology compared to [217], but more conservative than the 0.02 $/kWh suggested in [218], but still an order of magnitude lower than CAES or PHS (10–120 and 60–150 €/kWh respectively) [217]. For further cost comparison among the alternatives for storage and hydrogen, the reader is referred to [28,219,220].

Other large scale storage alternative – H_2 injection to the grid

Alternatively, the hydrogen could be injected to the existing grid and not use a 100% H_2 system. This would require a balance between de-risking of the existing infrastructure to increase the regulatory H_2 content and satisfying the need for storage. The worst case (for H_2 content) is that hydrogen would be generated during summer, when gas demand is low. The hydrogen fraction depends on the specific characteristics of the

[23] http://forschung-energiespeicher.info/projektschau/gesamtliste/projekt-einzelansicht//Potenzial_von_Kavernen_vorhersagen.

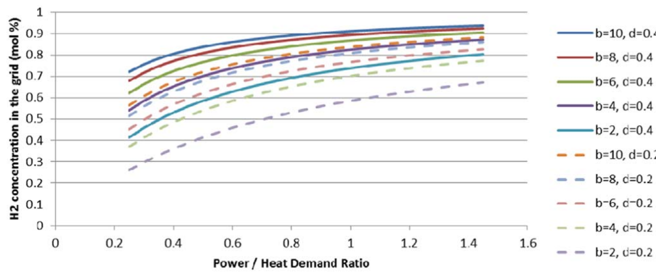

Fig. 7. Average H_2 content in the NG grid for different system characteristics.

network like: ratio between heat and power demand, fluctuations (min/max) for each one and amount of instantaneous surplus. This can be calculated with a generic approach as expressed in equation below and the H_2 content for different assumptions can be seen in Fig. 7.

$$H_2(mol\%) = \frac{\frac{2*a}{a+1}*\frac{d}{LHV_1}}{\frac{2*a}{a+1}*\frac{d}{LHV_1} + \frac{2}{b+1}*\frac{1}{c*LHV_2}}$$

Where:

a = Max/min ratio over a year for power (typical value = 3)

b = Max/min ratio over a year for heat (typical value = 10)

c = Average power/average heat ratio (value for EU ~0.5, see Appendix D)

d = Power surplus/Max power demand (dependent on VRE fraction, must-run fraction, but usually large fractions will only be a few hours of the year)

LHV_1 = 12.75 MJ/m^3 (Hydrogen)

LHV_2 = 40 MJ/m^3 (Natural Gas, with a typical range of 35–42 MJ/m^3)

The curves on Fig. 5 represent the H_2 concentration when the heat demand is the lowest and the power surplus is the highest. A disadvantage of hydrogen is the low volumetric heating value, its ratio of almost 1:3 to methane will increase the corresponding fraction for the same amount of energy. The other one is that the large fluctuations in heat demand (extrapolated to gas demand) makes the hydrogen amount more significant since there are larger fluctuations in the gas flow. Even for the case, where the heat (gas) demand is relatively stable (a ratio of 2 between maximum and minimum) and the power surplus is only 0.2 of the maximum capacity, it creates a concentration of 25% H_2 in the grid. A further correction to this number is that this would represent the average of the entire network. In places where the power production is higher or where the gas demand is lower, the concentration will be higher than the average value. Therefore, the de-risking required and the amount of hydrogen in the grid might be too high and represents a large departure from current practices.

Power to Liquid

Continuing the comparison in terms of energy density, as highlighted before one option with a higher energy content than hydrogen is methane (ratio of 3:10 in H_2:CH_4). This places methane in the order of ~1000 kWh/m^3 depending on the pressure assumed and if the energy considered is the energy stored or the energy provided back to the grid (through CCGT). Nevertheless, an even higher density option are liquid fuels, diesel based on purely LHV can be ~9000 kWh/m^3 [221].

This solution could provide a lower CO_2 solution and would also use the existing infrastructure, value chains and devices in the more difficult to replace sectors of maritime and aviation transport. The transformation could be with Reverse Water Gas Shift (RWGS) to produce Syngas and then either Methanol or Fischer Tropsch. Alternatively, CO_2 and H_2 could be used directly for methanol synthesis and then to jet fuel [222] or gasoline (through the MTG process with DME as intermediate). The efficiency for this process is between 40–60% depending on the CO_2 source, heat integration and scheme used. The intention in this section is not to discuss the details of the technology, future improvements and techno-economic evaluation of the different business cases. For these, the reader is referred to [223,224]. The objective instead is to compare the storage capability of this option compared to the others in case the power surplus from VRE is diversified to the transport sector through the use of the same fuels being used today rather than with new routes (i.e. electric, CNG or FCEV).

As shown before in Fig. 4, the transport sector is ~ 30,000 TWh, which is larger than the entire electricity sector. For the total oil storage capacity, there is a distinction between strategic reserves usually held by public entities (government) and commercial inventories. IEA countries are actually required to maintain a storage inventory of at least 90 days of average import capacity. In reality, the average is ~200 days[24] since both private and public inventories are considered and both primary and refined products. This amounts to 4.2 bln barrels (1.6 bln in the form of public stocks exclusively for emergency purposes and 2.6 bln that includes commercial stocks and fraction imposed by the government to meet the energy security requirement) [IEA 2014]. This is already equivalent to ~7000 TWh (assuming an average LHV of 145.7 MJ/barrel). Considering that IEA countries represent around 50% of the global oil demand,[25] that other countries do not have such strict requirement for strategic reserve (if at all) and that these numbers are actually inventory (and not maximum storage capacity), it can be assumed that the global storage capacity can easily surpass ~ 12,000 TWh. Even without accounting for its possible growth in the coming years, it shows that it is much higher than the possible requirements for storage of the power surplus and that not a big change is required to accommodate such surplus in this sector.

[24] http://www.iea.org/netimports/.

[25] http://www.iea.org/Sankey/#?c=World&s=Balance.

Appendix C. Underground salt deposits and cavern fields

see Figs. 8–10

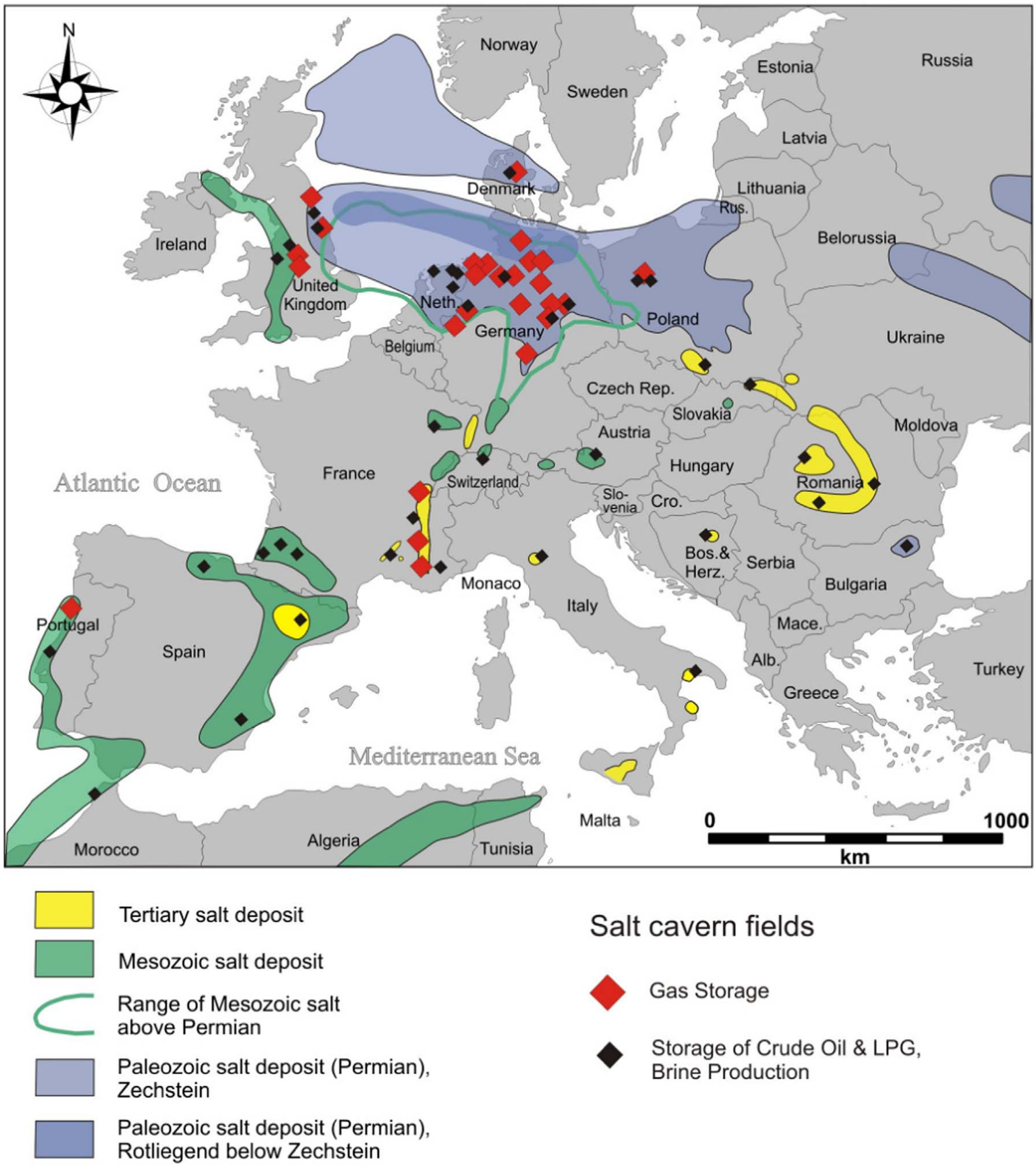

Fig. 8. Underground salt deposits and cavern fields in Europe [225].

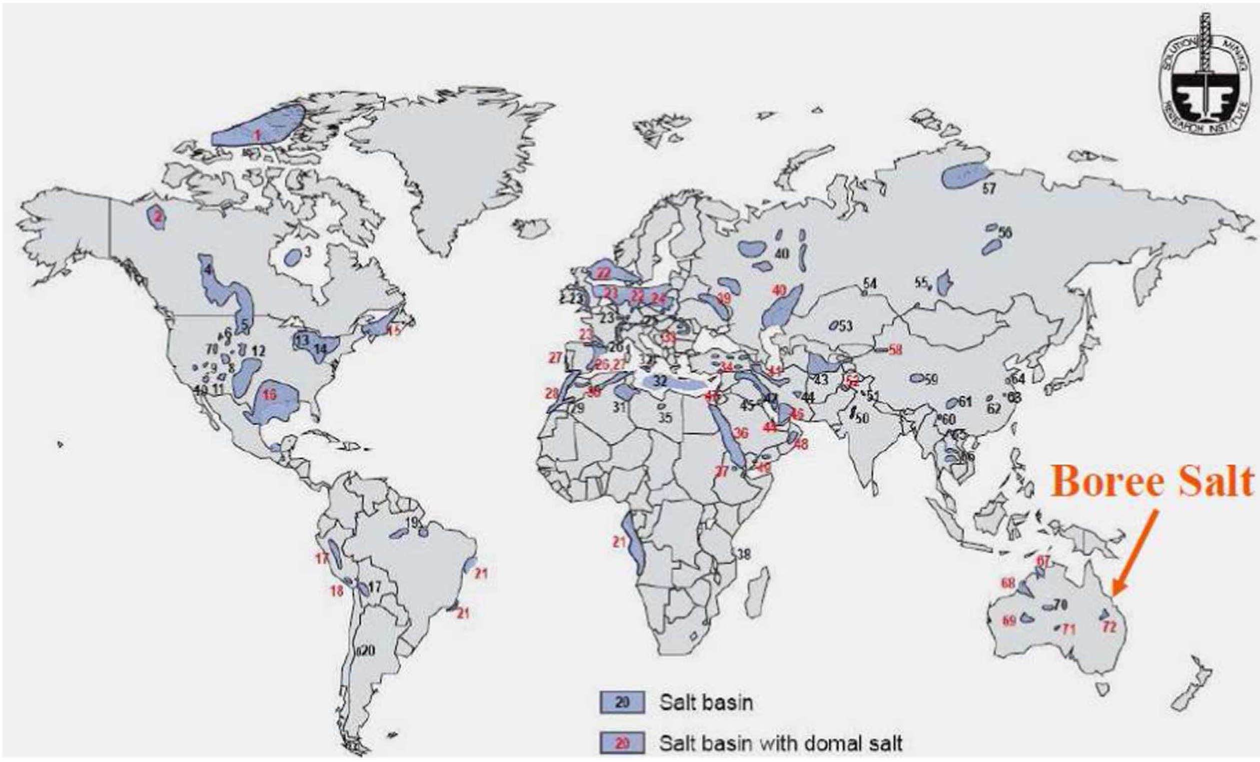

Fig. 9. Underground salt deposits in the world [226].

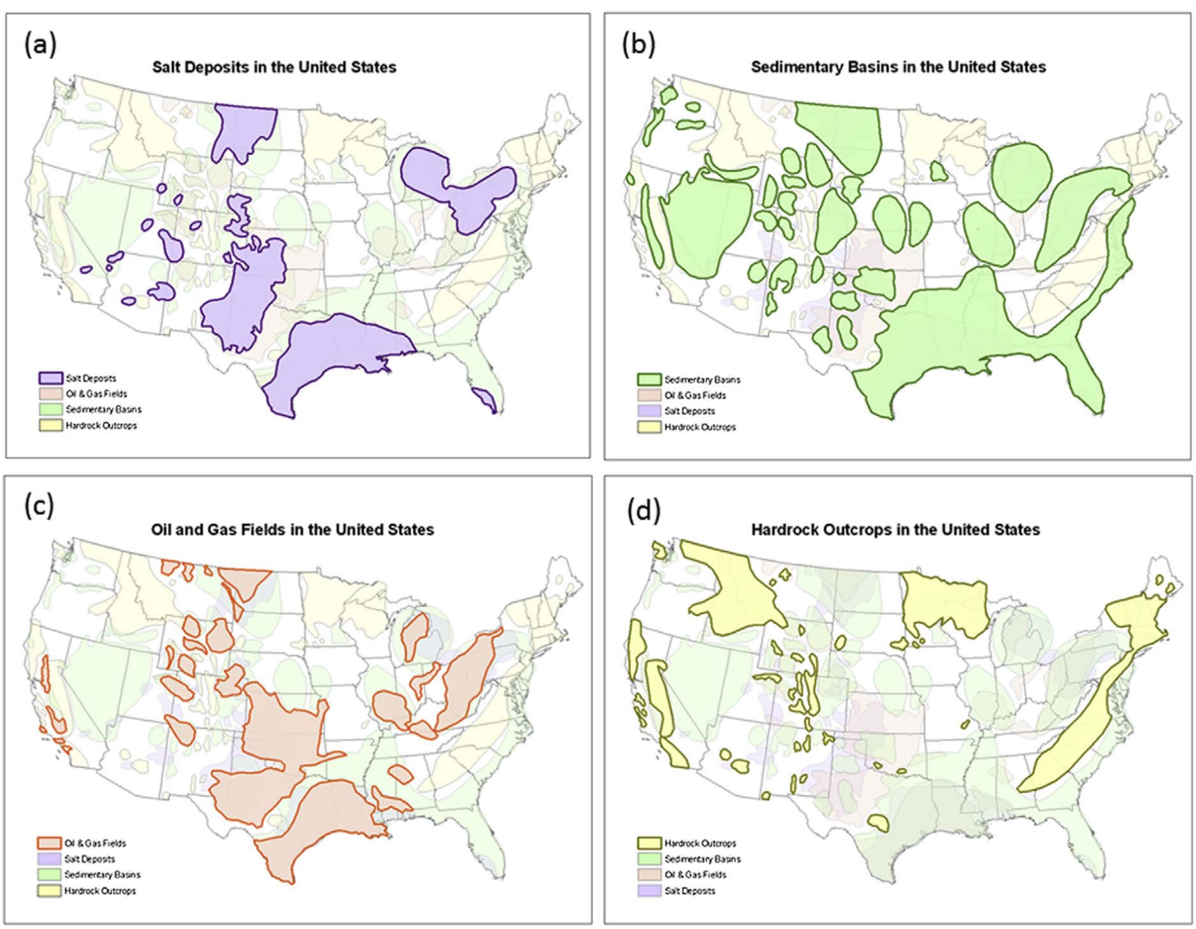

Fig. 10. Geologic maps of the United States displaying the location of major formations for (1) salt deposits, (2) sedimentary basins, (3) major oil and gas fields, and (4) hard rock outcrops [227].

Appendix D. Power (2015) and Heat demand (2012) for EU28

	Power (TWh)	Heat (TWh)
European Union (28 countries)	3063	6020
Euro area (19 countries)	2185	
Belgium	71	200
Bulgaria	44	25
Czech Republic	81	140
Denmark	31	45
Germany (until 1990 former territory of the FRG)	598	1320
Estonia	11	10
Ireland	26	30
Greece	47	60
Spain	272	390
France	545	760
Croatia	13	10
Italy	271	730
Cyprus	4	
Latvia	5	10
Lithuania	5	10
Luxembourg	4	5
Hungary	27	95
Malta	2	
Netherlands	99	280
Austria	66	170
Poland	146	380
Portugal	52	40
Romania	61	110
Slovenia	17	10
Slovakia	25	80
Finland	65	160
Sweden	150	180
United Kingdom	325	700
Iceland	18	
Norway	142	70

*Power from Eurostat – nrg_105a_1 and heat from [198].

Appendix E. P2G pathways and degrees of freedom for selecting configuration

P2G Pathways

There are different degrees of freedom along the value chain for P2G that give rise to different pathways.

Similar to Power to Hydrogen, there could be different sources for the input electricity and the final energy carrier can be used in all the sectors. A key difference for Power to Gas is CO_2 as a raw material and participating in the reaction, which can partially be seen as a constraint since CO_2 has to be readily available in the vicinity of the P2G plant. Nevertheless, it is also seen as reducing the overall CO_2 footprint since it further utilizes CO_2 that otherwise could have been released to the atmosphere. Another degree of freedom is the production of hydrogen instead of methane. This could be done depending on the price spread, local demand, operational issues. Once a P2G plant is constructed, the more possibilities for revenue streams it has, the better the operational and economical performance will be. A possible scheme for the P2G plant is that the methanation step is sized smaller than the electrolyzer with an intermediate storage. This allows the electrolyzer, which has a better dynamic response, to adjust to the changes in electricity input, while allowing for a more stable operation of the methanation reactor that might need more stable operation depending on the type of reactor and its design. Furthermore, it allows decoupling both steps and increasing the flexibility of the plant. The different possibilities for P2G, along with degrees of freedom in the value chain are shown in Fig. 11.

The first degree of freedom is the source for the electricity, where a trade-off between operating hours in a year, overall LCA footprint and economics should be done, taking into account the RES penetration and footprint of the grid. In a region with a high CO_2 footprint for the grid electricity (e.g. China), it is not environmentally attractive to convert part of that power to gas for further use in either back to power or another sector. For this case, the low efficiency of the process does not favor the competition with other sources and will make the footprint of the produced gas even larger than the electricity input footprint. On the other extreme, to tackle this issue, the plant could operate only with renewable energy or when there is a surplus that cannot be absorbed by the rest of the system. Furthermore, in this case, it can be assumed that since the energy was supposed to be curtailed, its cost will be zero or at least much lower than average. This is the ideal situation since the LCA footprint for the process would the smallest (with wind) [187], but the number of operating hours might be too low to justify the investment [178], where at least 2000–2500 h in a year are required to achieve the largest decrease in LCOE cost and ideally 5000 h to have around 90% of the possible cost reduction and reach similar prices as natural gas[26] [182]. This number of hours with surplus could be reached depending on the variables highlighted in Section 3,

[26] Depending on the electricity, consideration of oxygen, heat, water.

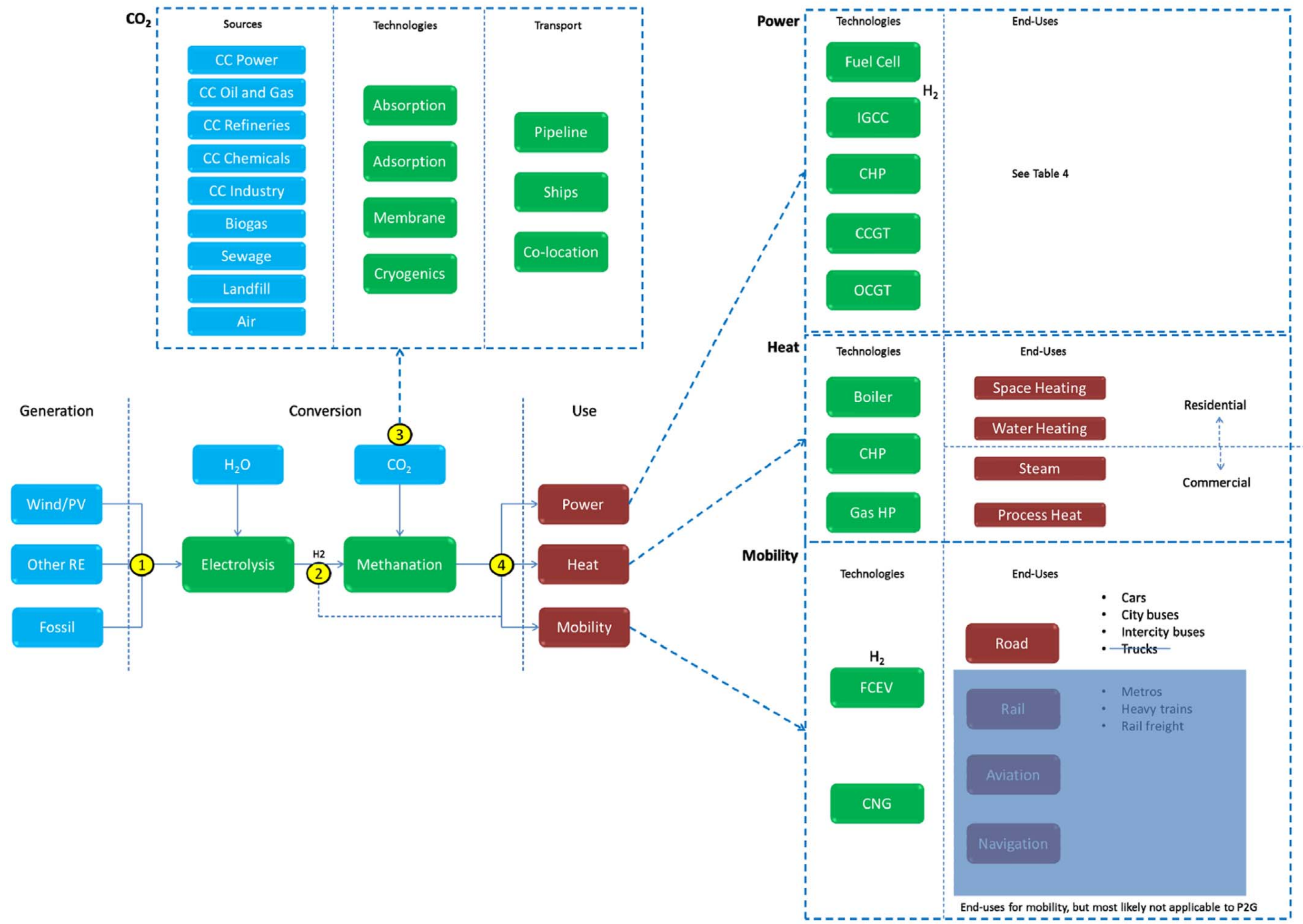

Fig. 11. Possible degrees of freedom in the value chain for P2G.

but for example in [47], 2000 h are reached with 20% of the generation being must-run and 40% VRE or in [192], where wind provides ~35% of the energy (with 50% of installed capacity) leading to curtailment of 11.8% of the energy in around 3600 h. However, adding P2G (50 MW unit vs a power system of ~14 GW of installed capacity) had little effect over curtailment (11.4% after P2G) and the P2G operated with an average electricity price of 58€/MWh to be able to operate 4100 h. Finally, a factor to consider is dynamics and time availability of power surplus. A case might be that peaks are too spread in time and would require shutting down and starting back up the electrolyzer or that the transmission of surplus from the source to the P2G plant is not possible due to line congestion at that time.

The capability of independent sizing of power and energy capacity is specially relevant for high levels of VRE. The power capacity can influence the minimum level of curtailment that can be achieved (i.e. if power capacity is too small, it does not matter if the storage has the equivalent energy capacity of two months of demand, it will not reduce curtailment). On the other hand, a high energy capacity allows reducing further the wasted energy once a power capacity big enough is available. This was seen for the German system with 100% VRE [228].

Another degree of freedom is the choice of final energy carrier. It could be gas, when the production rate is too high and might reach the established H_2 limit in the natural gas grid, when the intended use is for heating (that are usually not adapted to operate with H_2). In contrast, if there is a chemical facility nearby that needs hydrogen [229], it might be more beneficial (and efficient) to satisfy that demand and produce hydrogen instead of methane. This will depend on the specific conditions for the site.

For the CO_2, the degrees of freedom are: source, technology used to capture it and means of transport to the P2G plant. Additional variables are allocation of capture cost and CO_2 footprint among unit providing it and P2G plant. For more on these, refer to [11,178].

In the power sector, there is a range of possible applications for storage. For US, the most complete list of services has been defined in [230] and [117]. However, the list of services is different from the European system, but that has been harmonized by [15]. A total of 7 studies (including the previously mentioned) were reviewed to make an inventory of the possible applications by [106], where 12 main categories were identified. Research publications reviewing the storage technologies, usually discuss its possible applications at the same time [16,21,231]. From these, a list with the possible applications and typical ranges for size and time frame has been extracted and shown in Table 7, where the objective is to identify the range of applications where P2G might be attractive.

For the short-term applications, efficiency is key since it will directly impact the LCOE and cost of electricity provided back to the grid [232]. Even with the high electricity prices in the balancing market, P2G is not attractive for this purpose [175]. The revenue is directly proportional to the storage efficiency, where reducing the efficiency from ideal (100%) to 60% can reduce the revenue by 75% [26]. This effect would be even more pronounced considering P2G (power-to-power) efficiency can be around 25%.[27]

[27] Electrolysis: 75%, Methanation: 80%, Compression: 80%, Transport: 90%, CCGT: 60%.

The ideal applications are the ones that require relatively large power capacity and longer discharge durations that result in large energy capacities (exploiting the advantage of P2G). These are highlighted in Table 7, with a disadvantage being that usually these applications are the ones with the lowest revenue to capture [117,233].

The range of intermediate power and discharge applications will depend on the specific arrangement of the system being evaluated and the degree of flexibility that P2G proves to have. Given that the electrolyzer and the re-injection to the grid can be individually sized, the positive and negative compensations that can be provided to the grid can capture different value.

For the heating sector, most of the appliances in EU are tested with a G222 gas that is a mix of 23% H_2 and balance of methane [114]. Even though, it depends on the specific Wobbe Index of the original gas and long-term tests are required, it gives an indication that final appliances could adequately function with some H_2 in it. Nevertheless, to be used in the heating sector, methane would have preference.

In terms of replacing gasoline and diesel with lower well-to-wheel footprints, CNG cars are currently in the lead with 1.3% of the car fleet (~890 million cars [234]), followed by electric cars with 1.26 million units [235] and only 550 units (cars+buses) with fuel cells in 2015 [236]. For the future, a great growth in electric cars is expected, reaching 100–140 million vehicles in 2030, while a more modest growth is expected in FCEV, which are not expected to become significant in the market before 2025. Therefore, considering other sectors of transportation and the possibilities for methane (or hydrogen), it will be more difficult to have a share in those. Hence, these end sectors are discarded for the methane produced.

Besides market demand, H_2 tolerance and technology suitability, the other variable to take into account is the levelized cost for the competing alternative that relates to the affordable production cost for the gas (either hydrogen or methane). The sector with the highest price is mobility [190,214], where either a very low electricity price (< 15 €/MWh) [178,237] for the input needs to be used or a high CO_2 price (~100 €/ton) [190] that increases the reference (i.e. gasoline) price should be considered for P2G to be attractive. The price for the conventional alternatives is 30–50 €/MWh for natural gas, while biomethane can be 60–100 €/MWh [237]. On the other hand, gasoline has a base cost of ~80 €/MWh [178], which could increase to ~160 €/MWh [237]with the introduction of a 100 €/ton tax on CO_2. Compared to a production cost with P2G of 90–130 €/MWh [182,237] only for the electricity component. Hence, it is not only the Capex component of the electrolyzer, but the efficiency that need to improve.

Depending on the specific pathway chosen and the specific elements used, the overall efficiency of the process will be different. Even with fixed elements, variables like cell degradation, ramping rates, operating voltage, catalyst deactivation, operating pressures, among others will affect the efficiency. The efficiency range for the common P2G value chain components is shown in Table 8.

Table 7
Storage applications in the power system by increasing size and response time.

Increasing power and discharge time

	Size (MW)	Response time	Discharge duration	
Transportation	< 0.05	msec-sec	sec-h	Discarded
Bridging power	0.1 - 1	sec	min-h	
Telecommunications back-up	< 1	msec	msec	
Power quality	< 1	msec	msec-sec	
Emergency back-up	< 1	msec - min	msec-min	
Motor starting	< 1	msec-sec	sec-min	
Grid fluctuation supression	< 1	msec	min	
Grid fluctuation supression	< 1	msec	min	
Spinning reserve	< 1	sec	min-h	
End-user reliability	< 1	msec	h	
UPS	< 5	sec	min-h	
RES Back-up	0.1 - 40	sec-min	sec-min	
Low voltage ride through	< 10	msec	min	
Voltage regulation	< 10	msec	min	
RES smoothing	< 20	sec	min-h	
Black start	< 40	min	sec-h	
T&D stabilization	< 100	msec	msec-sec	
Peak shaving	0.1 - 100	min	h	Ideal
Ramping and load following	1 - 100	sec	h	
Time shifting	1 - 100	min	h	
Load levelling	1 - 100	min	h	
Standing reserve	1 - 100	min	h	
Energy management	> 100	min	h-d	
Seasonal storage	30 - 500	min	h-d	

*Definitions for these applications is given in Appendix E

Table 8
Efficiencies for individual components of a common P2G value chain.

Step	Technology	Efficiency range (%)	Typical value (%)
Electrolysis	Alkaline (AEL)	62–82 [177], 47.2–82.3 [238]	70
	Polymer Electrolyte Membrane (PEM)	67–82 [177], 48.5–65.5 [238], 0.7–0.86 [236]	75
	Solid Oxide Electrolysis Cells (SOEC)	89	–
Methanation	Biological	> 95 [177]	95
	Catalytic	70–85 [177]	80
Compression	Reciprocating compressor	85–95	90
Underground Storage	–	95–98	98
Re-conversion to power	Open Cycle Gas Turbine	30–40	35
	Combined Cycle	55–65	60

Appendix F. Applications of storage in the power network (from [16])

- Integration of renewable power generation: The inherent intermittent renewable generation can be backed up, stabilized or smoothed through integration with EES facilities.
- Emergency and telecommunications back-up power: In the case of power failure, EES systems can be operated as an emergency power supply to provide adequate power to important users including telecommunication systems until the main supply is restored, or to ensure the system enabling orderly shutdown. For emergency back-up power, instant-to-medium response time and relatively long duration of discharge time are required. For example, one of the world's first utility (hybrid) CAES back-up systems was recently installed at a Co-op Bank data center to provide an emergency supply of electricity. For telecommunications back-up, the instant response time is essential.
- Ramping and load following: EES facilities can provide support in following load changes to electricity demand. One EES trial project, named Irvine Smart Grid Demonstration, using advanced batteries (25 kW) in California offers services in load following and voltage support.
- Time shifting: Time shifting can be achieved by storing electrical energy when it is less expensive and then using or selling the stored energy during peak demand periods. EES technologies are required to provide power ratings in the range of around 1–100 MW. PHS, CAES and conventional batteries have experience in this service; flow batteries, solar fuels and TES have demonstration plants or are potentially available for this application.
- Peak shaving and load levelling: Peak shaving means using energy stored at off-peak periods to compensate electrical power generation during periods of maximum power demand. This function of EES can provide economic benefits by mitigating the need to use expensive peak electricity generation.
- Load levelling is a method of balancing the large fluctuations associated with electricity demand. Conventional batteries and flow batteries in peak shaving applications, as well as in load following and time shifting, need a reduction in overall cost and an increase in the cycling times to enhance their competitiveness.
- Seasonal energy storage: Storing energy in the time frame of months, for community seasonal space heating and the energy networks with large seasonal variation in power generation and consumption. EES technologies which have a very large energy capacity and almost zero self-discharge are required. At present, there are no commercialized EES technologies for this application and storing fossil fuels is still a practical solution. PHS, hydrogen-based fuel cells, CAES, TES and solar fuels have potential to serve this application.
- Low voltage ride-through: It is crucial to some electrical devices, especially to renewable generation systems. It is a capability associated with voltage control operating through the periods of external grid voltage dips. High power ability and instant response are essential for this application.
- Transmission and distribution stabilization: EES systems can be used to support the synchronous operation of components on a power transmission line or a distribution unit to regulate power quality, to reduce congestion and/or to ensure the system operating under normal working conditions. Instant response and relatively large power capacity with grid demand are essential for such applications.
- Black-start: EES can provide capability to a system for its startup from a shutdown condition without taking power from the grid.
- Voltage regulation and control: Electric power systems react dynamically to changes in active and reactive power, thus influencing the magnitude and profile of the voltage in networks. With the functions of EES facilities, the control of voltage dynamic behaviors can be improved. Several EES technologies can be used or potentially used for voltage control solutions.
- Grid/network fluctuation suppression: Some power electronic, information and communication systems in the grid/network are highly sensitive to power related fluctuation. EES facilities can provide the function to protect these systems, which requires the capabilities of high ramp power rates and high cycling times with fast response time.
- Spinning reserve: In the case of a fast increase in generation (or a decrease in load) to result in a contingency, EES systems can feature the function of spinning reserve. The EES units must respond immediately and have the ability of maintaining the outputs for up to a few hours.
- Transportation applications: Providing power to transportation, such as HEVs and EVs. High energy density, small dimension, light weight and fast response are necessary for implemented EES units. For instance, a hybrid powertrain using fuel cell, battery, and supercapacitor technologies for the tramway was simulated based on commercially available devices, and a predicative control strategy was implemented for performance requirements.
- Uninterruptible Power Supply (UPS): EES systems can feature the function of UPS to maintain electrical load power in the event of the power interruption or to provide protection from a power surge. A typical UPS device offers instantaneous (or near to instantaneous) reaction, by supplying energy mostly stored in batteries, flywheels or supercapacitors.
- Standing reserve: In order to balance the supply and demand of electricity on a certain timescale, EES facilities/plants can provide service as temporary extra generating units to the middle-to-large scale grid. Standing reserve can be used to deal with actual demand being greater than forecast demand and/or plant breakdowns.

Appendix G. Overview of P2G studies and area of focus

	End product		Type of study								
	Methane	Hydrogen	LCOE	Process design	Time series	Potential	Business model	Technology review	Cost optimization	LCA	Projects Survey
Buchholz 2014 [165]	x			x							
Gotz 2016 [11]	x	x						x			
Connolly 2014 [161]	x	x	x								
Jentsch 2014 [77]	x								x		
DNV 2013 [177]	x	x						x			
GRTGaz 2014 [179]	x	x	x			x		x			
Saint Jean 2014 [167]	x			x							
Saint Jean 2015 [239]	x		x								
Vartiainen 2016 [186]	x	x									x
Klumpp 2015 [162]	x	x	x								
Clegg 2015 [181]	x	x							x		
Varone 2015 [168]	x				x						
Estermann 2016 [169]	x				x						
Dickinson 2010 [164]	x			x							
Schiebahn 2015 [178]	x	x	x					x			
Schaaf 2014 [240]	x							x			
SGC 2013 [180]	x	x	x					x			
Bailera 2016 [241]	x		x	x							
Vandewalle 2015 [194]	x		x						x		
Schneider 2015 [191]	x					x					
Giglio 2015a [166]	x			x							
Giglio 2015b [242]	x		x								
Plessmann 2014 [193]	x		x						x		
Kotter 2015 [76]	x		x						x		
Moeller 2014 [108]	x								x		
Breyer 2015 [163]	x		x				x				
Zoss 2016a [170]	x				x						
Zoss 2016b [243]	x					x					
Ronsch 2016 [244]	x							x			
Ahern 2015 [192]	x		x		x						
Belderbos 2015 [104]	x								x		
Henning 2015 [195]	x	x							x		
DVGW 2013 [189]	x	x	x						x		
Jurgensen 2014 [245]	x					x					
Dzene 2015 [246]	x					x					
Reiter 2015a [183]	x					x					
Meylan 2016 [247]	x									x	
EIL 2014 [172]	x	x	x			x		x		x	x
ENEA 2016 [237]	x	x	x					x			x
Parra 2016 [188]	x	x	x						x		
Budny 2015 [175]	x	x					x				
de Boer 2014 [99]	x	x			x						
Palzer 2014 [125]	x	x							x		
ECN 2013 [190]	x	x	x			x			x		
Schaber 2013 [44]	x	x	x						x		
DENA 2016 [171]	x					x					x
Fraunhofer 2015 [173]	x	x				x			x		
Schmied 2014 [174]	x					x					
Sternberg 2015 [184]	x									x	
Sternberg 2016 [185]	x									x	
Heinisch 2015 [248]	x								x		
Baumann 2013 [249]		x					x				
Julch 2016 [220]	x	x	x								
Gahleitner 2013a [250]	x	x								x	
Reiter 2015b [187]	x	x								x	
Zhang 2017 [251]	x									x	
Meylan 2017 [252]	x									x	
Vo 2017 [253]	x		x			x					

Collet 2017 [254]	x		x	x		
Ye 2017 [255]	x			x		
Zeng 2016 [256]	x			x		
Bailera 2017a [257]	x		x	x		
Spazzafumo 2016 [258]	x		x			
Iskov 2013 [259]	x					x
Bailera 2017b [260]	x					x
Parra 2017 [261]	x	x	x		x	
Rivaloro 2014 [262]	x		x			

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