Sector Coupling: Concepts, State-of-the-art and Perspectives

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WHITE PAPER

Sector Coupling:
Concepts, State-of-the-art and Perspectives

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0 FOREWORD

EtipSnet is issuing this White Paper on a transversal topic currently high in R&D and Innovation agendas across Europe and beyond. The purpose is to contribute to the debate with sound, unbiased information and future outlooks from experts spanning the wide and articulated knowledge base constituing the EtipSnet platform.

As per definition of White Paper, no specific positions are taken towards or against each technology or process; rather, the objetives are:

- to establish a shared ground of definitions, concepts and common language/understandings on the topic;

- to propose a structured mindset for analysing in a consistent way the projects proposed in the framework of sector coupling and to assess the relevant business cases;

- contents-wise, to provide the state-of-the-art and perspective of conversion and end-use technologies;

- to give an outlook at the potential application deployment in the horizon of RD&I Roadmap;

- possibly, to identify at early stage the barriers to deployment, both technical and non-technical;

- to present some use-cases.

The target audience is therefore the energy R&D community in wide sense, decision makers, grid operators, project proponents, companies and utilities involved in the set-up of projects in this field.

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The document is organised as follows:

- Section 1 on framing the issue and proposing shared defintions;

- Section 2 on role of storage for Sector Coupling;

- Sections 3, 4 and 5 on, respectively, Power to Heat/Cooling, Power to Mobility and Power to Gas, following the same overall structure:

- Technologies, status of implementation and costs, also showing future expectations;
- System integration potential, with benefits and scale of implementation, both for the power sector and for the other coupled sectors;
- Barriers to deployment and possible solutions.

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A second White Paper should follow, focusing on: architectures and evolving eco-system, enabling technologies and skills, ICT / IoT requirements, all levels of interoperability, enabling markets and platforms, business models, regulatory challenges and sandboxes needs.

1 INTRODUCTION - WHY SECTOR COUPLING?

The COP21 Paris Agreement on climate protection, and the "Europe Clean Planet for all Europeans" strategic long-term vision for a prosperous, modern, competitive and climate-neutral economy [1] which address full decarbonisation of the energy system by 2050, mean that many countries have begun to seriously plan for a low-carbon electricity system in a shorter timeframe than typical replacement times of power plant and network equipment.

Renewable energy sources (RES), especially solar and wind, as well as storage technologies, have shown strong cost and performance improvements; they shall be the pillars, together with energy efficiency, of most long-term decarbonisation strategies, in combination (according to specific countries' energy policies) with other carbon-neutral energy sources[1], carbon capture and storage/usage[2], use of (certified) green gases, integration of different energy sectors,.

Since greenhouse gas emissions, including CO_2, do not only come from the electricity generation, but also from transport, heating/cooling, industry and agriculture, many countries aim at decarbonizing (at the level of climate-neutral impact) the entire energy system, including these other sectors.

In particular, the transport and heating sectors emit significant quantities of greenhouse gases and they can be electrified in cost-effective way. This calls for planning and realising a system successfully integrating energy carriers and sectors such as electricity, gas, transport and heating, i.e. a System of Systems. This in turn increases the importance of energy grids, and in particular of the electricity grid as backbone of the other networks.

At an EU level, energy consumption has been stable since 1990 with a decrease in consumption in the industry and an increase in transport and services, which can be seen in Figure 1.1.

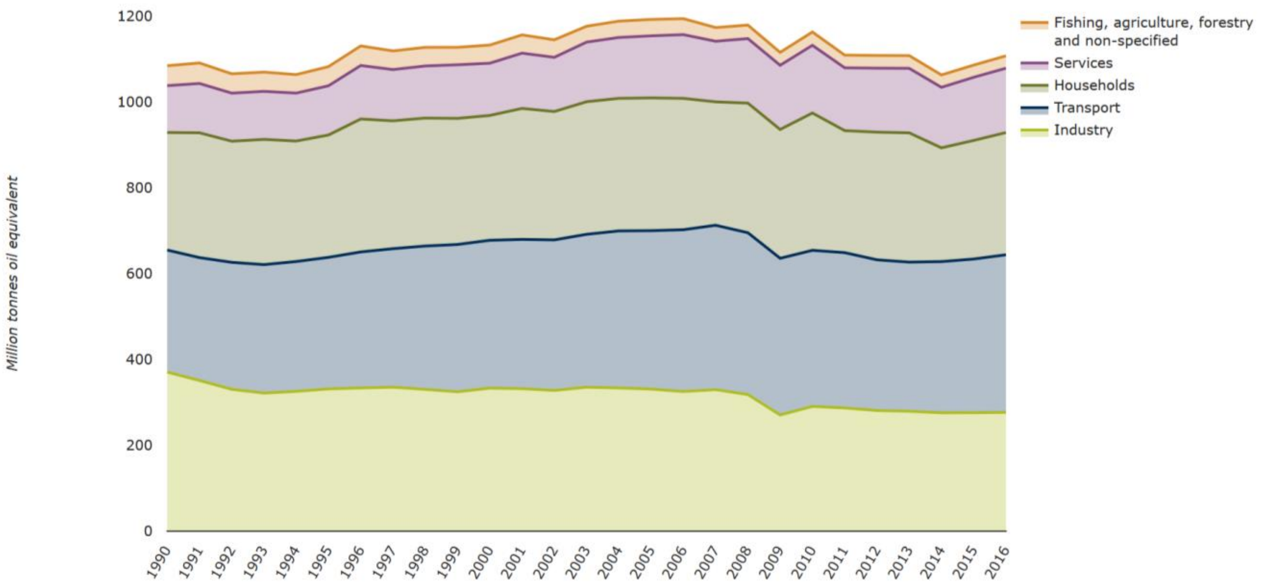


Figure 1.1: Final energy consumption, EU 28 [3]

The share of electricity in the final energy consumption is currently around 35% in industry and

[1] Among which nuclear power, which causes moderate CO2 life-cycle emissions, however, the waste disposal and associated risk are not sustainable nor fullfilling a circular economy.

[2] Carbon capture and use (CCU) is only sustainable in long term as long it is based on biogenic CO2.

30% in households and services and only around 3% in transport as shown in Figure 1.2.

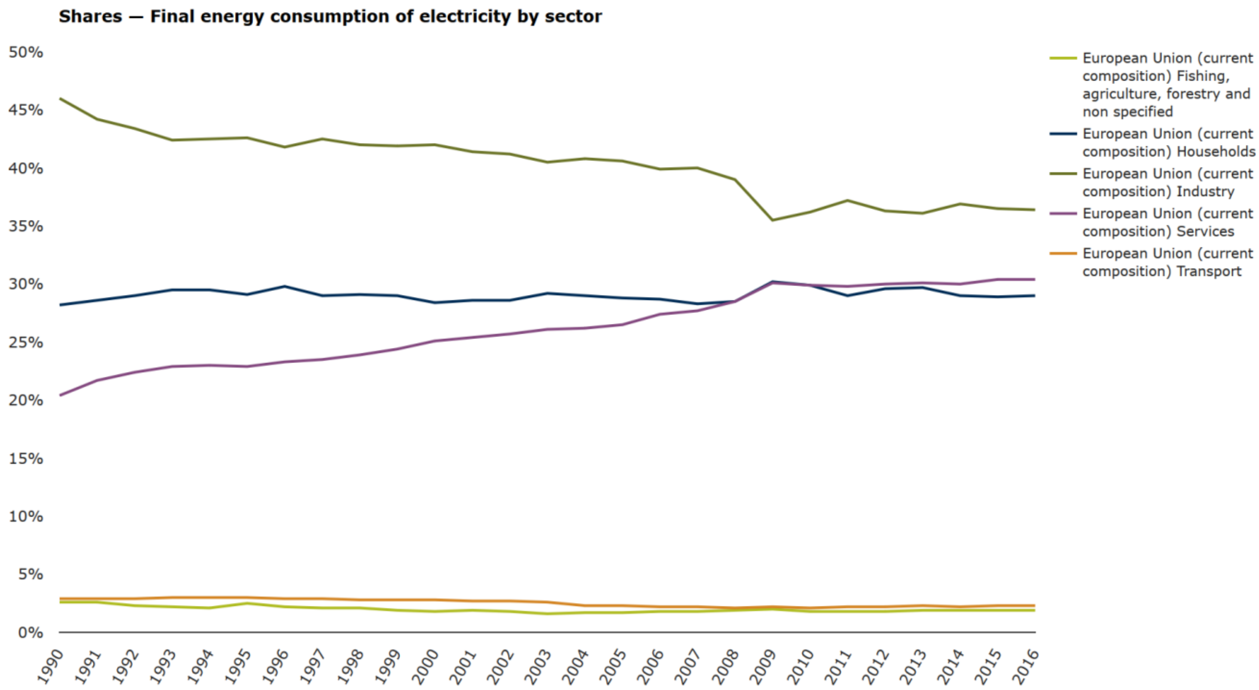


Figure 1.2: Final energy consumption of electricity by sector, EU 28 [3]

In all these sectors, electrification using electricity supplied from renewable sources is expected to provide a solution for decreasing GHG emissions and consequently the demand for electricity is expected to increase substantially[3]. In its decarbonisation pathways aiming at 95% GHG emission reductions in 2050, Eurelectric for example expects an increase from current final electricity consumption of 22% up to 60% in these sectors combined. This would result in an annual growth in electricity supply of 2.6% resulting in more than a doubling of the electricity demand, although energy efficiency improvements reducing 1.3% of total energy consumption per year is assumed simultaneously. [2]

Decarbonisation brings new challenges in operational and planning activities in terms of risk of stranded assets but also opportunities for enhanced system optimisation across energy sectors and networks.

The balance between the three traditional goals of electricity supply: reliability, economic affordability and sustainability, is changing: until the 1980s, reliability was a hard constraint, sustainability (environment) was captured in certain constraints without very extensive influence on planning decisions, and economics were optimized usually from the perspective of a single integrated electricity utility. Today, the environment and climate protection impose the tightest constraints, reliability is assessed in probabilistic way in risk analysis terms, thus becoming a function of economics with demand response and price-elastic loads, and the economic performance is the result of market mechanisms involving millions of participants, enormous uncertainties, across different countries and sectors, and definitely with the inclusion of a CO2 price that properly considers the external costs caused by the CO2-emissions.

[3] This increase of electricity by electrification will be somewhat offset as global consumption by electric efficiency improvements of electrical end-use equipment.

1.1 THE RISE OF THE SECTOR COUPLING CONCEPT

Sector coupling has recently gained increased attention, bringing new complexity into infrastructure investment decisions but also new opportunities for its smart operation. In a multi-energy system the benefits of an investment in one system may spread over other connected sectors, calling for new metrics when evaluating the cost-benefit analysis (CBA) and for widening scenarios of investment decisions to alternative solutions in the cross-energy system which can be more economical. For example, the storage of energy within the electric system (hydro, batteries, etc.)[4] can be conveniently replaced by storing energy in other forms (thermal, sytnhetic gases, etc.). In this perspective, the electricity sector shall play an important role in decarbonizing also the other sectors, which in turn provide additional flexibility options to safely operate the electricity grid. Power to Power options, such as large scale batteries, may also assist in this matter, but do not constitute sector coupling per se and are hence not included in this White Paper. An integrated energy system with coupled sectors can be illustrated as in Figure 1.3

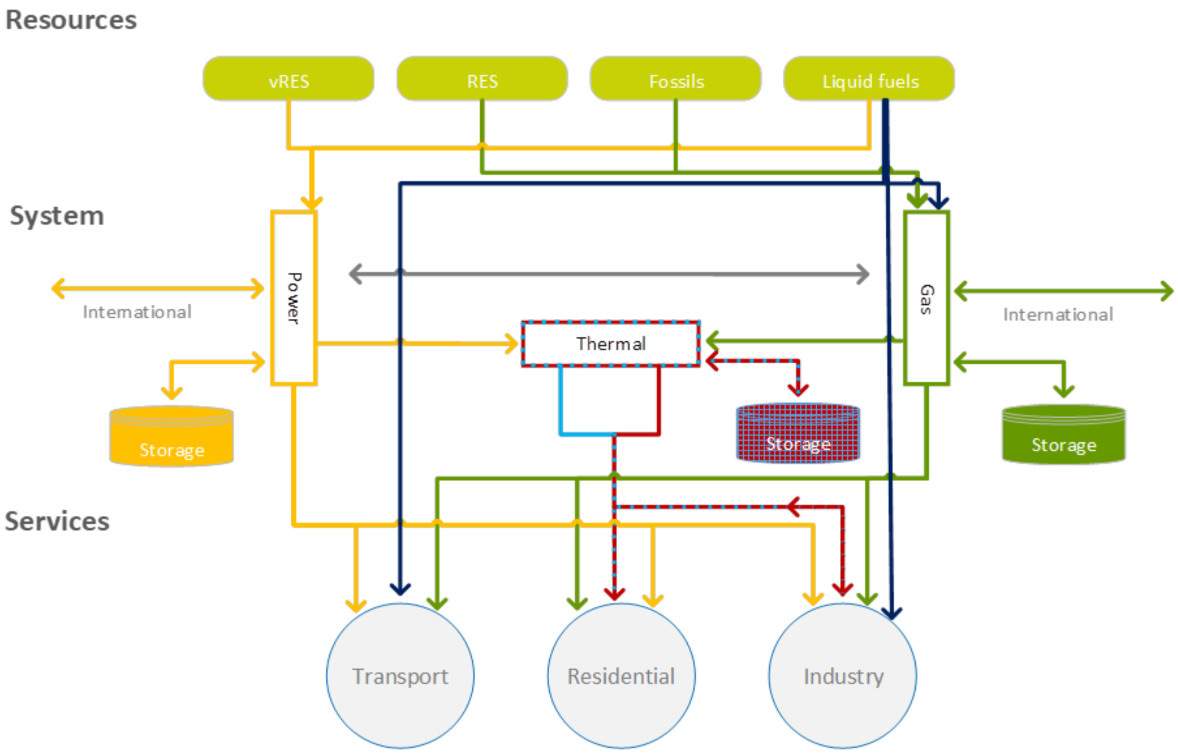


Figure 1.3: Scheme of possible interactions among energy vectors

Sector coupling brings new challenges such as: amount and shape of electric demand growth with electrification of heating and transport; how much distribution-grid based system reinforcement is needed to accommodate the charging of Electric Vehicles (EV) or electricity needs of Heat Pumps (HP), and when in the coming decades or years these devices should be installed; whether the costs of electrolysers for power-to-gas decrases significantly , and how that affects the economics of electricity vs. gas transmission and distribution.

There are great expectations about the role of sector coupling in the achievement of a swift, economical efficient green transition with a high security of supply, but it is unclear to which extent current technologies can provide on this agenda. This ETIP SNET White Paper aims to elaborate on those questions, starting with clarification of concepts and assessment of potential impacts.

[4] Electricity itself is not storable as electric energy in large amounts; however, storage within the electricity system refers to storage of electrically pumped-up water in higher-elevation hydro basins or chemical storage in batteries, where storage and/or flow control are the only use of such devices. Release of energy from hydro basins and from batteries occurs again directly as electricity.

1.2 INHERENT ECONOMIC DRIVERS OF SECTOR COUPLING

The versatility of electricity, the energy efficiency of its application in transport and heating compared to the use of fossil fuels, the relatively low cost of decarbonizing electricity generation with low-cost solar and wind energy, and last but not least, the fact that its value changes in very short time intervals by a powerful price signal for consumers, mean that its value will affect market equilibria naturally in all sectors. In the past, fossil fuels had that role, and electricity quotations as well as prices for heating and transport were indexed to coal, oil and gas prices.

Seasonal storage may play a major part in carbon-neutral supply of all energy needs; this is true already in countries where heating or cooling dominates the dynamic of load profiles (especailly on an annual basis). Apart from hydro storage, heat storage or power-to-hydrogen/power-to-gas can transform summer renewable electricity surpluses of sunny countries into energy available also during windless winter weeks and conversely for Nordic windy countries. This is best driven by electricity price signals: low electricity generation costs and prices – due to surplus renewable energy at low operating cost – indicate that some of the surplus energy should be injected into seasonal storage because its value in a different season is higher, even after energy conversion losses, and vice versa for withdrawals from seasonal storage during higher-price periods[5].

The decarbonisation of the energy system implies also a significant rate of electrification of end-consumption, which may reach up to 65 % of total energy demand by 2050 [4,5,6]. In any case, there are categories of industrial users, which will still need to use “molecules” which requires development of PtX technologies. Some PtX technologies can provide long-term flexibility.

Eventually, a key issue will be to achieve convergence on externalities/social impacts’ evaluation across sectors. This is today in separated silos due to their legacy of totally separated economic approaches. [7]

1.3 BUSINESS STAGES WHICH CAN BE IMPACTED BY SECTOR COUPLING

In order to frame the broad sector coupling topic, methodological progress is still needed, at various stages of the electricity system management:

- System Planning: power system planning must account for the progressive electrification of different energy sectors like heating and transport already underway (EVs, heat pumps). The challenges are to correctly forecast the pace of change, depending not only on technological advancements but also on incentives from policies/tariffs, the impacts on peak demand (from kW in households to GW in national and continental systems) and on energy supply (from kWh to TWh), and to properly take into account all direct and indirect effects.

- System Operation: the electrification of transport and heating provides new opportunities of flexibility for the operation of electricity grids, complementary to the existing means. Flexible generation, pumped and storage hydro, grid re-configuration, electrochemical storage and demand-side management make it possible to adjust the conversion rate and their inherent storage capability, in order to balance out surpluses or deficits of variable Renewable Energy Sources (vRES) production; a much sought-after alternative to their curtailing.

- Optimization of energy carriers: conversion and storage of electric energy can be extended not only to non-traditional electrical loads (EV, heating) but also to fuels: methane, hydrogen,

[5] The challenge of designing a marginal operating costs and related bid-based markets with renewables-based electricity generation only (both during winter and during summer, during nights and during days) is not yet resolved today. The value of storage is evident, but today’s market models are not yet providing definitive answers how to consider the (marginal) value (and investment cost) of storage together with almost zero-marginal costs (but high investment costs) of renewable generation and the flexibility of demands when establishing prices in electricity markets.

green gases, fuels, which have their own transport infrastructures (pipelines, ships, tankers) and storage infrastructures (tanks, reservoirs, flowing stock). This allows storing energy in form of molecules with no intrinsic energy losses, as well as transporting large stored amounts of energy economically (and in the future also fully sustainable by renewable sources for any type of stored energy transport), due to their intrinsic high energy density. To optimize conversion and storage across sectors, a coordinated infrastructure planning of all involved energy systems may be required.

● Market Design & Regulation: market configuration and mechanisms shall be adjusted to the new technological possibilities and be designed in order to stimulate the positive effects of sector coupling. Cross-sector regulation requires dialogue and coordination among different regulatory bodies.

● Business models, ownership and governance: coordinating across sectors also means coordination among many different actors, often as first-of-a-kind interaction. Governance and rules have to be established, together with ownership and operation roles, as basis for economic exchanges in trading energy and services. These issues go beyond the scope of this technical White Paper, but are mentioned here since they become paramount when putting sector coupling initiatives into practice. Consequently, relevant and suitable business models shall be developed for a concrete viability of the projects.

1.4 FRAMING AND CONCEPTS OF SECTOR COUPLING

Traditionally, system balancing between electricity sources and electricity sinks is performed moving energy in space (from one geographic location to another one), through the electrical grids, because no direct electricity sources were available locally, local storage options were very limited, much more expensive or too lossy; the development of new, lower-cost, easy to operate and better performing storage technologies together with access to locally available renewable energy sources adds the chance of balancing the system also by shifting the use of electric energy in time.

For decades, engineers have operated the power system with the philosophy of "Generation follows the load":

● load profile was given as an independent variable, responding purely to end consumers wishes, who had no price signal influencing their behaviour;

● generation mix was planned and operated to cover consumers' needs, thereby exploiting the generation plants intrinsic flexibility, due both to the technical possibility of controlling the desired output within a wide range below the nominal power and to the presence of stored fuel/water on site;[6]

● storage was available only with hydro pump plants, of large-size but few obliged locations.

In the future system the opposite paradigm shall apply (see Table 1.1 below):

● generation mix shall be dominated by , i.e. with a production profile according to primary source availability, so ultimately according to weather conditions[7];

● load profile shall become partially depending on demand/supply balance through appropriate

[6] For the sake of clarity, vRES are considered inflexible because their curiailment has a strong economic disavantage, due to their nature of high Capex-low Opex cost structure, on the contrary of tradional thermal plants.

[7] This refers to the generation plant stand alone, its inflexibility can be mitigated adding a local storage, which is one of the options to provide the flexibility needed by the system

price mechanisms for each market time interval (demand response);

- the bulk of power balancing shall rely on several flexibility means, both old and new;
- additional storage options (in quantity and quality) shall be provided through conversion to non-electric energy forms.

Table 1.1: Operational philosophies

	Generation profile	**Storage**	**Load profile**	**Operational Philosophy**
Past	Flexible (due to directly connected storage vector)	Limited to hydro basins	Inelastic	Generation follows the load
Present	Largely flexible, but hardly challenged by “residual load” profile	Hydro, gas, thermal and batteries	Mostly inelastic	Pursuing the needed balance with flexibility means in infancy stages
Future	Mostly inflexible (vRES)	Many options, including power-to-X	Elastic (partially)	Load (+storage) follows the generation

In a future energy system with sector coupling, grid and system operators shall have many and sophisticated means for managing flexibility both at short and long-term, which will be needed, requiring smart tools and methods (Figure 1.4). In this respect, flexibility means can be classified in:

- equipment/processes within the perimeter of the electric system (although not necessarily storing energy in form of electricity), and therefore under direct observability of grid operators and (according to regulation and business cases) potentially also under control of grid operators
- equipment/processes pertaining to other domains and therefore typically not controllable by electric gridoperators, which have to respect working criteria, needs and constraints typical of such external domains as well.

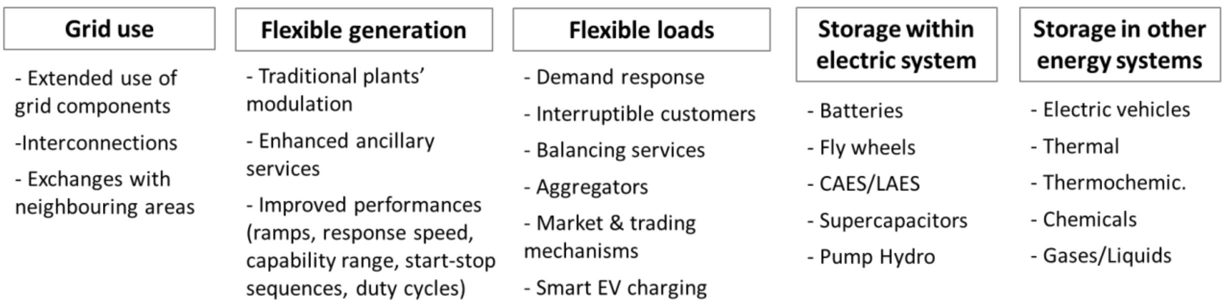


Figure 1.4: Scheme of flexibility means for electricity grid operators

In Fig. 1.4 the schematic classification is made from an electric system perspective, i.e mapping the various devices and processes available as a source of flexibility for the electric system operation. Without diving into flexibility needs, characteristics and comparison (out of scope of this White Paper), this explains the triple impact of EV batteries, which can be stacked one upon the other, in order of complexity:

- electrification, i.e. increased load and modified load profile; such loads are managed by EV owners according to their mobility needs, therefore outside of the control of electric system;

- flexible load, through smart charging they become a flexible load, like all those under demand response, with wide utilisation ranges (withdrawal from zero to rated power spanning over many hours, considering that city cars are typically idle for 90% of the day);

- storage, through reversible charging they assume also the role of a stationary battery, of course with extra operational constraints and limitations.

With the same perspective (electric system optimal operation), only pumped hydro are reported in the scheme, because these can store energy under the control of the electric system operator; on the contrary, basin hydro natural feed (no pump) are classified as flexible generation, whose production profile can be modulated by the plant owner according to the water availability over time.

Today, the main type of electricity-grid connected storage available is pumped hydro, which is used to provide both short-term and mid-term flexibility controlled by the electricity sector. More solutions will however be needed as many countries have limited potential for pumped hydro and other sectors may become instrumental in providing the required flexibility.

The main goal of power system management could become:

● Operation: how to best use and combine the many flexibility means available to optimise a vRES-based electricity generation having quasi-zero variable cost;

● Planning: optimise development of the electricity grid in coordinated manner with development of many other independent actors and sectors including the gas and heat/cooling networks; not only generation and load, but also new services and new interfaces.

The storage options outside the pure electric system identify the perimeter of sector coupling (Figure 1.5). Actually, sector coupling goes much beyond the pure storage scope: once energy is converted and injected in another sector, the issue arises of co-optimising the operation of the different involved sectors. A further consequence is the possibility of transporting bulk amounts of energy in one of these other forms, particularly when energy is trapped in molecules.

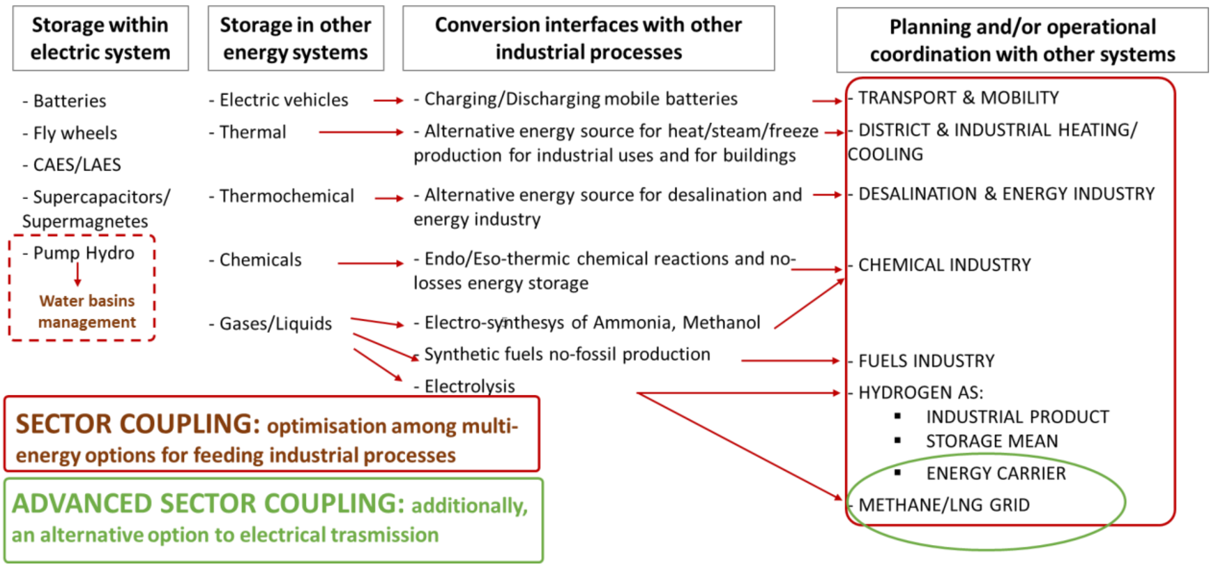


Figure 1.5: Perimeter of Sector Coupling

In a certain sense the traditional pumped hydro is a precursor of sector coupling, when the hydraulic regimes need to be coordinated with water basins/rivers authorities and constraints due to hydraulic flows (agriculture, irrigation, drinkable water); however, since this only poses extra limitations rather than providing extra flexibilities, hydro basins are not considered as sector coupling.

This triggers the important consideration that also gas systems are characterised by such inherent constraints which shall influence the PtXtP processes and as such the electricity system; same with EV-based charging stations with a possible need to make local intermediate storage available due to missing grid capacity (or the other way around). In synthesis, the existing other energy systems, when coupled with the electric one, shall still need to satisfy their vested mission, in so adding a reciprocal set of operational constraints to the optimal management pattern.

1.5 CONCEPTUAL COMPONENTS OF SECTOR COUPLING

Sector coupling consists of an energy conversion process towards an adjacent industrial sector, where the converted energy (net of conversion losses) can follow different paths:

- **stored** more easily outside than inside the electric system, for time-shifted, successive re-conversion to electricity: shift in time and in some cases also in space;

- **consumed** in another sector , if cheaper/cleaner than other energy sources typical of that sector, either temporarily (operational optimisation) or permanently (electrification);

- **transported** (in form of heat or gas/liquid), in some cases where transport performances can be higher than for transmitting and distributing electricity, or faster to realize considering societal constraints (building authorisations , environmental permits, public acceptance).

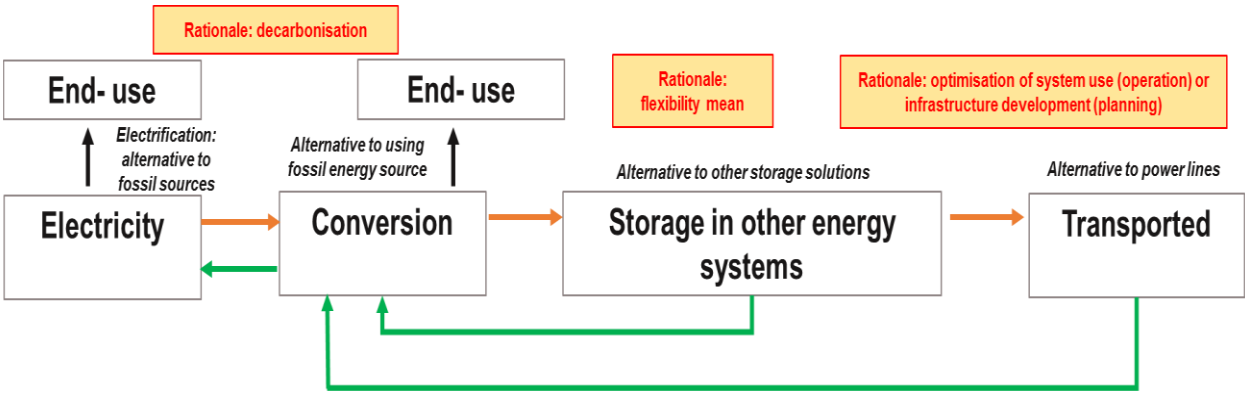


Figure 1.6: Stages of Sector Coupling

The wide array of combinations of the above options, makes sector coupling a complex multi-variables optimisation problem, with the objective of minimizing design and operational cost (CAPEX + OPEX), given decarbonisation targets and system-inherent boundary conditions and operational constraints.

A further element is the electrification of other sectors, which affects the picture by increasing the amount and localisation of coupling potentials (also in terms of demand response).

Another useful perspective for rationalising the matter is the distinction between end-uses and storage-oriented processes/energy flows, which are often entangled in the concept of sector coupling; this is shown in Figure 1.7 a) and b), which map the components of a power system evidencing that sector coupling combines the benefits of end-uses (flexible loads) and of storage devices.

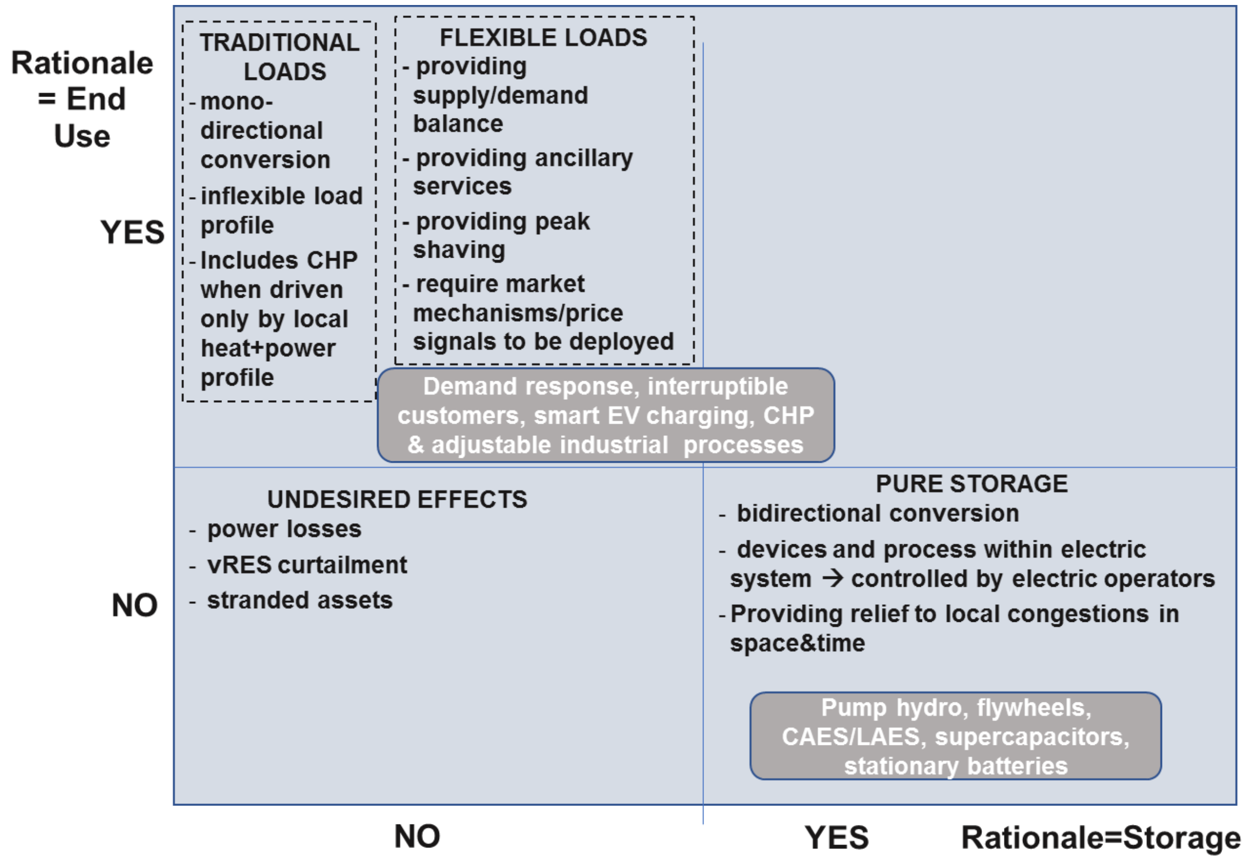


Figure 1.7a) Rationale and characteristics of energy flow processes

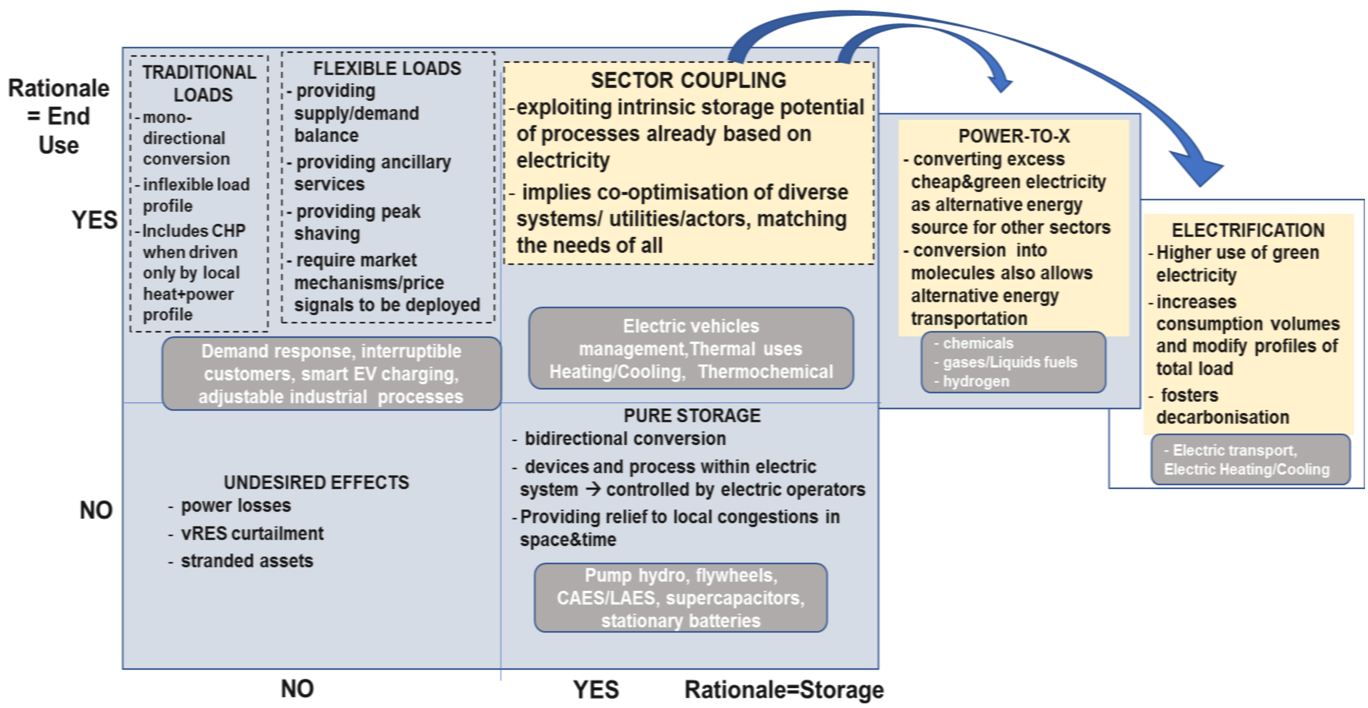


Figure 1.7b) Rationale and characteristics of energy flow processes

1.6 ENERGY CONVERSION (SECTOR INTERFACE)

The feasibility of any sector coupling initiative must be based on the techno-economic assessment of the underlying energy conversion process, including its potentials and limitations; the following sections and appendices elaborate on that.

The criteria used to identify the conversion processes of concrete interest are:

- conversion process already well proofed at industrial plant level, maybe to be scaled-up and/or engineered at grid level;
- conversion only of bulk quantities, i.e. in size able to impact on power system flows substantially;
- conversion of bi-directional type, with a high energy efficiency and high number/frequency of duty cycles;
- for this White Paper, only conversion where at least one form of energy (directly or indirectly) is electrical.

The characteristics and functionalities relevant for the techno-economic assessment of a conversion process are:

- efficiency rate, mono and bi-directional: they may not be symmetrical (some conversions are mono-directional so the electricity is lost for the electricity system);
- limits/constraints on energy and power size, modularity;
- dynamic characteristics: time for flow direction change, ramp up/down capabilities, external system constraints, number and frequency of duty cycles;
- costs: capital, operational, maintenance, replacement, financial; in particular, externalities have to be carefully investigated and, if present, properly taken into the picture

1.7 FLEXIBILITY, STORAGE, POWER-TO-X, ELECTRIFICATION: NOT SYNONYMS OF SECTOR COUPLING

Terminology and standardised concepts are also important; Fig. 1.8 shows the characteristics and services rendered to the electricity system with the categories of conversion processes previously described. Strictly speaking, Power-to-X should regard only conversion to a non-electric form of energy, but it is commonly used for all conversions to other sectors. In any case it refers to the conversion stage, while the term sector coupling itself should then be reserved to the more general perspective of coordinated operation/planning of several systems together. In other documents, the term Multi Energy Systems is used as synonym of sector coupling.

Typology --> Characteristics	Pure load (traditional)	Flexible Load	Storage in electric sytem	Storage in other energy systems	Molecules (chemicals & gases)
Energy Conversion / End Use	End Use	End Use	Conversion	Conversion	Conversion
Energy Flow reversible	NO	NO	YES	YES	YES
Controlled by electricity actors	YES	YES	YES	NO	NO
Providing storage capabilities	NO	NO	YES	YES	YES
Providing flexibility capabilities	NO	YES	YES	YES	YES
Energy carrier capabilities	NO	NO	NO	NO	YES

storage
Energy carrier
flexibility

SECTOR COUPLING

POWER – TO - X

Figure 1.8: Overview of sector coupling concepts and characteristics

2 ROLE OF STORAGE FOR SECTOR COUPLING

Storage of energy in the enlarged power system is a vast topic on its own, rapidly evolving and with many applications already in place, of remarkably different technical and economic characteristics; market rules and regulation are being adapted to a world with a mostly Capex (little Opex) asset base to be paid-off through market mechanisms: transport infrastructures (pipelines, electric lines, submarine cables), storage plants (hydro dams, batteries, caverns for CCS, etc.) RES generation plants (solar, wind, hydro, geothermal, heat pumps, etc.). Storage is one of the indispensable means for providing the increasing flexibility needs in particular of the electricity system, the most impacted by penetration of intermittent and weather-dependent vRES.

However, storage technologies and characteristics as such are out of scope of this White Paper, and they are briefly mentioned here only because storage is one of the important feature provided by sector coupling projects. Indeed, converting electricity into other energy forms/vectors shall provide additional options of storage through sector coupling, to be used when their characteristics and costs make it more convenient vs other storage options within the electric system.

Therefore only a schematic overview of comparative characteristics of storage options will be reported here, while more technical details are reported in Appendix 7.1 .

2.1 STORAGE TECHNOLOGIES

In order to cope with the exponentially growing demand for storage capabilities and performances, many technologies are being developed, as represented in Figure 2.1. Some of these technologies can deliver storage only for seconds and minutes, some for hours and days, while others provides storage for much longer time scales.Fig. 2.2 provides a comprehensive comparison of applicability cases; Fig. 2.3 provides an overview of installed capacities, while Fig 2.4 zooms in on the applicability mapping for batteries.

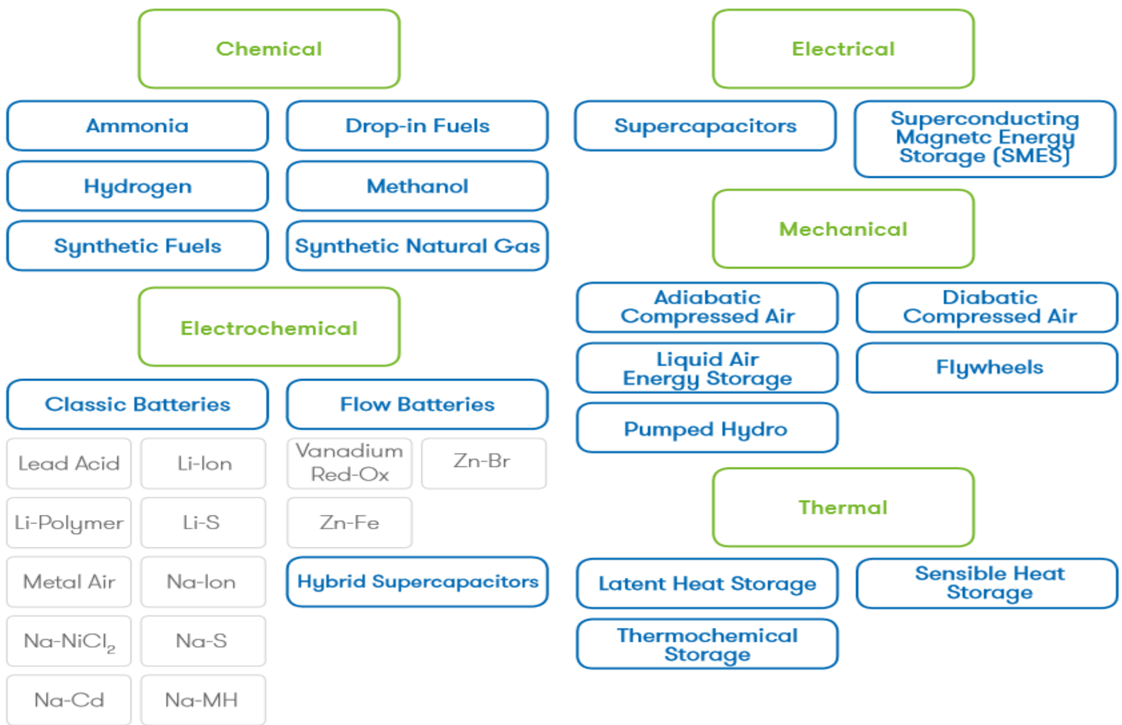


Figure 2.1: Comprehensive scheme of storage technologies

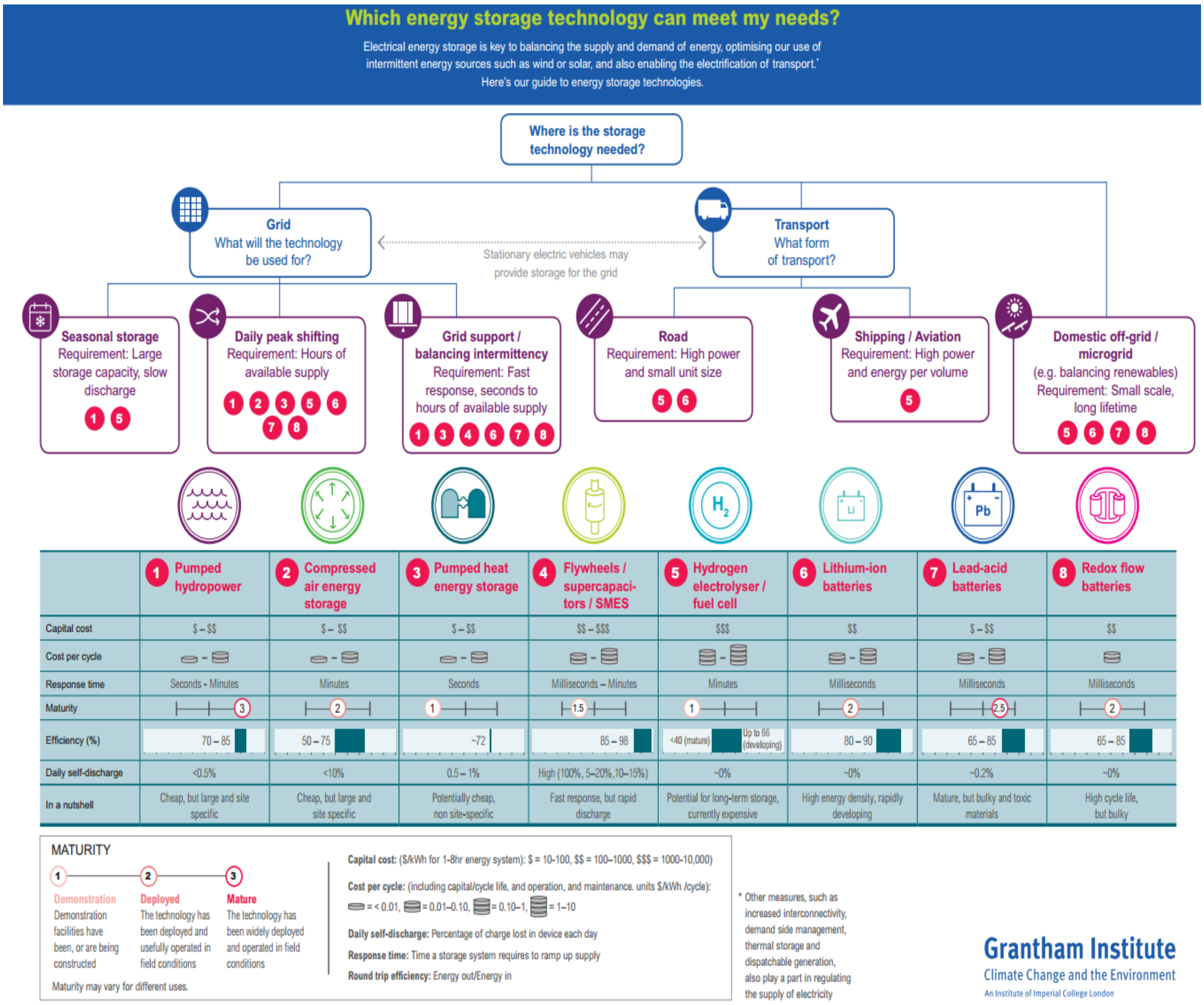


Figure 2.2: Comparative applicability of storage technologies

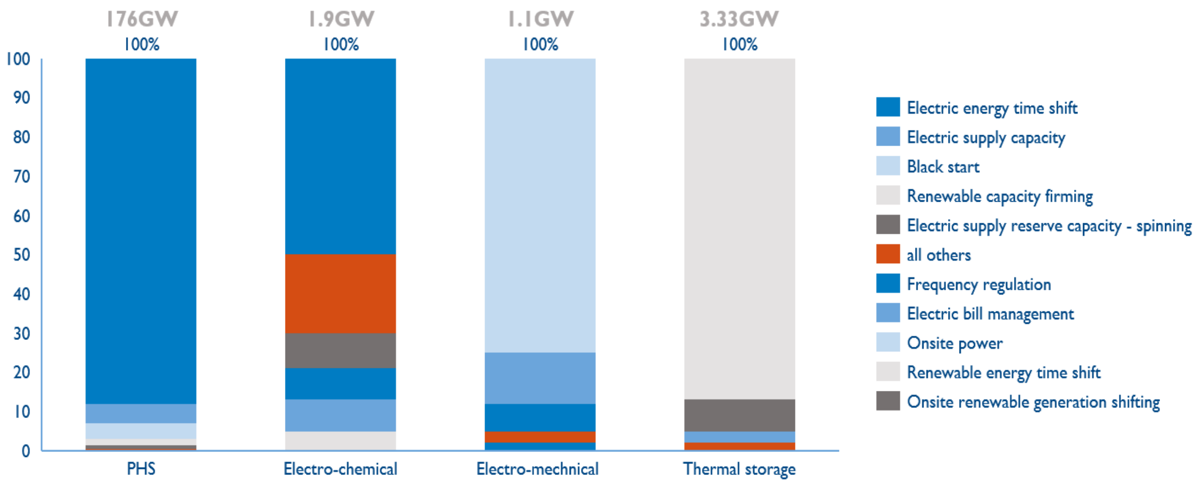


Figure 2.3:Global energy storage power capacity by main use case and technology [8],(IRENA, Energy Storage Outlook 2017)]

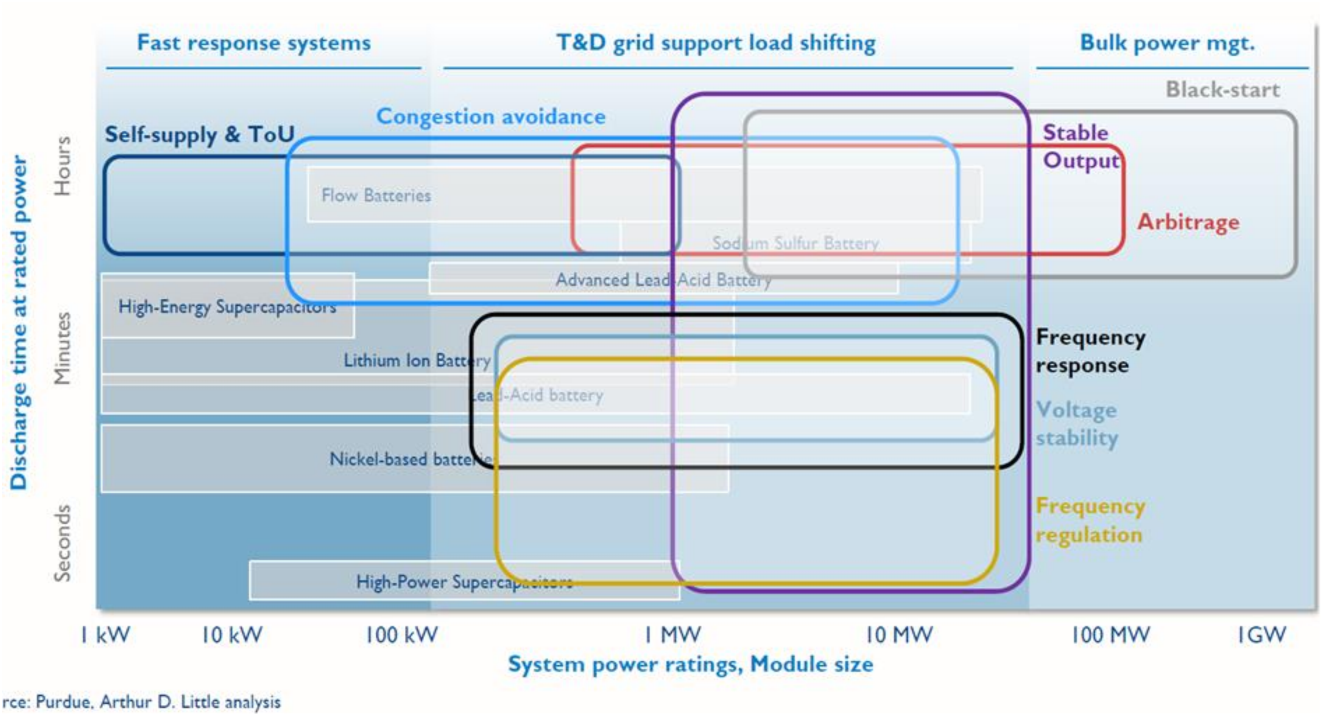


Figure 2.4: Batteries: mapping of technologies by applications and key functionalities

2.2 COMPARISON OF STORAGE FEATURES

Each proposed project of Sector Coupling, including a feature of storage, should be assessed for its techno-economical profitability against other forms of storage which can provide similar features. Such assessment can be done using the parameters listed in Table 2.1.

Table 2.1: Storage characteristics

Storage characteristics
Energy density
Energy capacity range
Conversion efficiency
Storage efficiency
Round trip efficiency
Extractable energy (depth- of-charge)
Number of life duty cycles
Cost per MW
Cost per MWh
Cost per cycle
Response speed
Application constraints
Modularity / scalability
Application cases (short vs long-term storage)
Maturity or TRL

3 POWER TO HEATING AND COOLING (PTH/C)

3.1 INTRODUCTION

The following considerations in this section 3.2 stem from a use case in UK [10,11,12]. An important caveat applies with regard to heating and cooling projects: context plays a significant role, where local conditions can influence the optimal solution (e.g. individual solutions vs. district heating). The examples applied in this chapter are thus illustrative, but will merit from context-specific analysis when approached nationally, regionally and especially locally.

Heating currently makes up around 50% [9] of the primary energy demand and has a 19.5% share of RE [10] in UK based on 2016 level. Due to e.g. low cost of incumbent technologies or lack of grid integration or flexibility signals (dynamic market-based prices), heating (and cooling) is a difficult sector to decarbonize. Electrification provides a potential for providing lower cost solutions scaling from household level to industry, as well as potentials for contributing to conversion and storage of fluctuating power in lower cost large-scale thermal storage systems.

The demand for cooling is currently only responsible for 2% of EU final energy demand [9], but this figure is expected to increase as thermal comfort demand levels will evolve in line with expected warming effects of climate change and also due to the effect that excellent building insulation may imply the need for more flexible, combined heating and cooling inside of strongly isolated buldings during each day of the year While heating demand coincides with wind power production during wintertime in the Nordic countries, Southern European cooling demand coincides with solar power peaks during daytime and therefore a good potential exists for efficient sector coupling with lower cost thermal storages.

3.2 PTH IN INDIVIDUAL RESIDENTIAL BUILDINGS

According to Eurostat database, individual residential buildings represent around 27% of final energy consumption in EU in 2017. Most of the energy consumed by domestic sectors (79.2%) is for heating and cooling. At present, the majority of EU countries depend on natural gas and fossil fuel or nuclear-based electricity generation or direct burning of oil or (natural) gas to meet the heat demand of domestic sectors. However, the essential requirement of decarbonisation necessitate the rollout of alternative low-carbon heating technologies for the transition to an environmentally friendly and sustainable energy system.

3.2.1 STATUS OF IMPLEMENTATION AND TECHNOLOGY

Based on most recent studies, renewable-fed electric heat pumps, renewables-fed district heating networks and renewables-based production of hydrogen are identified as promising technologies to deliver cost-effective low-carbon future energy system by coupling electricity and heat sectors through providing balancing services such as frequency response and various forms of reserve to facilitate efficient integration of variable renewables and – still during the transition towards a fully-circular energy system - inflexible nuclear-based electricity generation. Table 3.1 presents the attractiveness for different heating technologies regarding different considerations [9]. Large-scale deployment of electrical heat pumps for decarbonising heat sectors will require significant investment in low carbon electricity generation. This may also lead to significant increases in peak electricity demand and hence drive electricity distribution network reinforcement and investment in electricity generation able to respond in a flexible way to peak demandss. In this context, application of hybrid heat pumps (HHPs) that combine electric heat pumps (EHPs) with gas boilers[8] may have significant advantages based on the dual-fuel flexibility. The ability to switch HHPs between electricity and gas can also provide various services to the system, such as peak demand management to reduce investment in generation and network assets. In addition, fuel-cell based residential micro-CHP is also regarded as a potential technology to facilitate the integration of electricity and heat systems in the favour of cost-effectively decarbonise the future integrated energy system.

Table 3.1: Level of cost or impact of different low-carbon heating technologies

Urban and suburban properties	**Electrification** **(Heat pump)**	**District heating**	**Repurposed gas grids (Hydrogen)**
Cost/impact of decarbonised heat supply	Low	Low	High
Cost/impact of network activities	Medium	High	Low
Cost/impact of activities in customer premises	High	Low	Low
Need for new regulation	Low	High	Medium

3.2.2 SYSTEM INTEGRATION POTENTIAL

The interaction between electricity and heat sectors will play an important role in facilitating the cost effective transition to a low carbon energy system with high penetration of renewable generation. The absence of coordination would drive inefficient investments in both electricity and heat sectors (at both local and national level) [11]. On the other hand, inherent flexibility in heat sectors can be used to alleviate these challenges through coordinated operation and investment with the electricity system. It should be stressed that the most important driver of energy sectors coupling is the requirement of cost-efficiently decarbonizing the whole energy system, making it more effective to integrate various renewable energy sources. Therefore, the benefits of energy sectors coupling will be significantly influenced by the carbon emission targets for the years and decades to come until 2050 and later. Increased benefits will be achieved in a more demanding carbon scenario. The electricity and heat sectors can potentially be coupled through end-use heat pumps, district based CHPs and heat pumps, micro-CHP, electrolysis based hydrogen heating, etc. [10]. Overall, the coupling of the electricity and heat sectors can bring significant benefits by increasing the investment in the heating infrastructure in order to enhance the system flexibility that in turn can deliver larger cost savings in the electricity system, thus meeting the carbon target at a lower whole-system cost.

Fig.3.1 presents the annual savings regarding the investment and operational cost of the UK system in different system segments enabled by the integration of electricity and heat systems in two carbon scenarios considered. It shows that the annual saving is about £2.3bn/year under the overall carbon target of 100g CO2eq emissions/kWh while the saving increases to £6bn/year under the overall carbon target of 50g CO2eq emissions/kWh.

[8] Only in the transition period towards the fully carbon-free energy system in 2050, gas may still come in parts from natural gas sources. It shall be complemented as soon as possible by carbon-neutral gases or carbon-free gases such as biogas, syngas and green hydrogen.

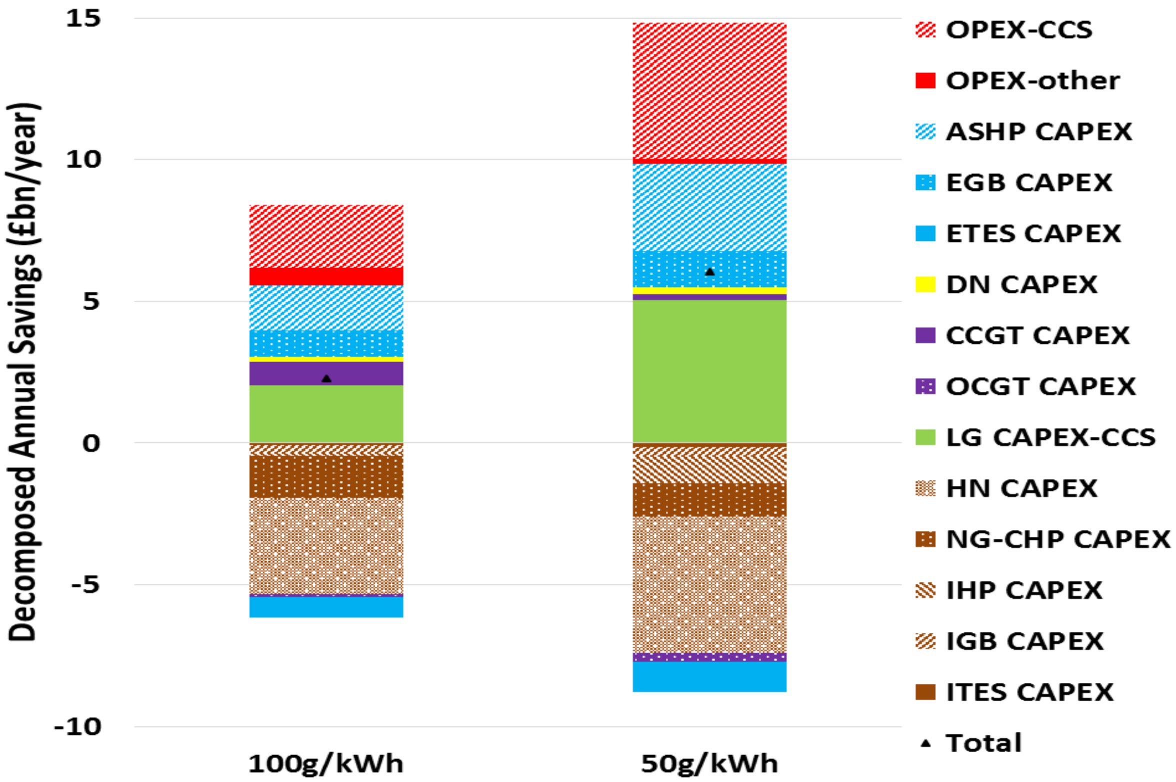


Figure 3.1: Savings from the optimised integration of electricity and heat systems

The integration of electricity and heat systems delivers significant savings in operation costs (OPEX), represented by red blocks, comprising operation costs of NG CCS, NG CHP, CCGT, OCGT and gas boilers, driven by significantly enhanced flexibility and efficiency of system operation through application of more efficient CHP and reduced renewable curtailment; Blue blocks indicate savings in capital costs (CAPEX) related to end-use heating technologies, including ASHP, end-use gas boilers (EGB), as a proportion of heat demand is supplied by HNs; Relatively minor investment savings are achieved in reducing capital expenditure associated with conventional generation (including CCGT and OCGT) and distribution networks (DN), as change in peak demand is not significant given that end-use heating is supplied by hybrid HPs (i.e. gas boilers are used to supply heat demand during peaks). Significant system integration driven savings are made by reducing the capacity of low-carbon generation (LG CAPEX), particularly referring to NG CCS (shown in green), as renewable generation is curtailed much less (particularly in 50g/kWh carbon scenario), so the carbon targets can be met by reducing NG CCS capacity. Brown blocks present additional integration driven capital expenditure (negative savings) in district heating, including heat network pipelines (HN), NG CHP plants, industrial heat pumps (IHP), industrial gas boilers (IGB), and industrial thermal energy storage (ITES). Additional investment in end-use thermal energy storage (ETES) is also driven by the system integration

Fundamentally, the benefits of the integrated, optimised investment planning come from the flexibility that the heat system provides to the electricity system, which significantly reduces both investment and operation costs of the electricity system, while increasing investment (but to a smaller extend than the decrease of costs in the electricity system) in the heat system.

Specifically, CHP, heat pumps and thermal energy storage, typically deployed in heat networks for residential heating, can provide ancillary services for the electricity system. Heat pumps, through temporarily decreasing their output (which will not compromise the comfort due to the thermal inertia of buildings), can also provide ancillary services. Moreover, unnoticeable for people, pre-heating in residential houses can further enhance the flexibility of the electricity system. In the planning stage, if we consider the flexibility which heat systems can potentially provide for the electricity systems, significant savings can be achieved in the electricity side on the cost of increasing the investment on the heat side, but the overall system costs are reduced significantly. If the heat system and electricity system are planned separately, the requirement of flexibility in the electricity system has to be met by the components within the electricity system, incurring dramatic flexibility associated cost, which will otherwise incur little extra costs with the flexibility provision from the heat systems [12].

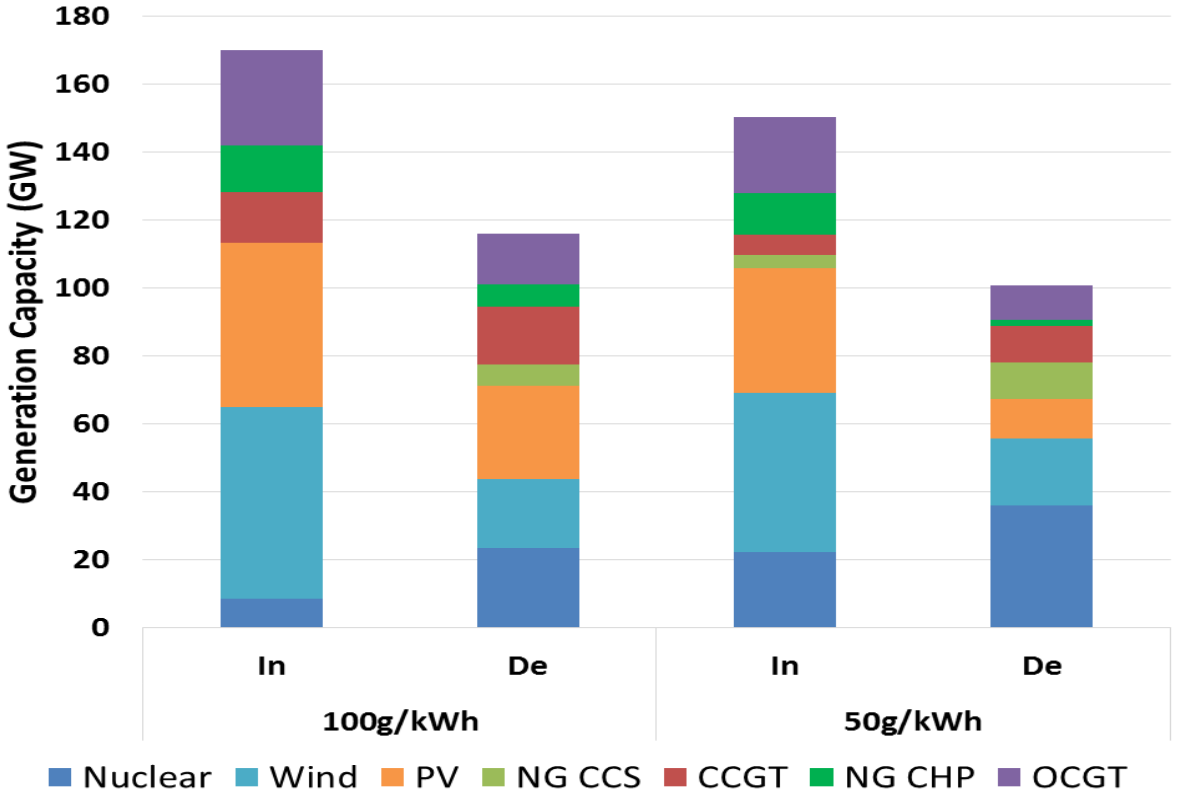


Figure 3.2: Cost optimal generation mix for different scenarios

Figure 3.2 demonstrates a cost-optimal portfolio of generation investment to deliver given carbon targets for the case of UK . It can be observed that considerable capacity of wind and PV generation is installed in the optimized, integrated energy system (“In” scenario in Fig.3.2) while in the decoupled scenarios (“De” in Fig. 3.2) more nuclear and Natural Gas CCS are required due to the inability of the system to effectively utilize RES services for the other energy system part. This is because the additional costs that are incurred due to the integration of RES can be significantly reduced by the increased flexibility provided with the integration of the electricity and heat system. This result indicates that coupling the energy sectors can significantly increase the utilization of RES.

3.2.3 BARRIERS AND SOLUTIONS

The lack/inadequacy of existing infrastructures will require very significant investments in new assets to deliver large-scale deployment of potential low-carbon heating technologies.

District Heating Networks (DHN) pathways are significantly more costly than other heat pathways due to the expenditure associated with the deployment of heat networks especially for the countries in which the penetration of DHN is still low. The use case analysed demonstrates that national deployment of district heating in the UK incurs a higher cost than the systems with domestic heating appliances. Tis is primarily driven by the cost of deploying heat networks and the cost of connecting consumers to heat networks, including new assets needed to control heat and the metering in dwellings. On the other hand, due to economies of scale, the cost of heating devices in the district heating networks is significantly lower (35%-50%) compared to the cost of domestic heating.

In the Electric pathway, there is also a significant reduction in the capital cost of the electricity generation driven by a higher COP of industrial HP (deployed in DHN) compared to the COP of domestic HP but this cost reduction is still lower compared to the increase in costs associated with heat network deployment and connection. While the analysis suggests that national scale deployment of district heating in UK may not be cost-effective, local application of district heating in high-heat-density areas could provide a more cost-effective solution as the cost of heat networks and disruption cost could be minimised. It is estimated that the cost of urban heat networks is less than 25% of the cost of heat networks in non-urban areas while heat demand in urban areas is estimated around 40% of the total heat demand.

Small-scale end-use micro-CHP can substitute the capacity of electric heating appliances, reduce distribution network costs and displace the capacity of gas-fired plants including hydrogen (or other green gases like carbon-neutral methan) power generation, while the impact on RES and the nuclear capacity requirement is marginal. This finding demonstrates that micro-CHP could provide firm capacity (assuming it is able to be managed to provide capacity during non-curtailable or non-shiftable peak demand occurrences) while significantly enhancing generation efficiency, as the heat produced from thermal electricity generation is not wasted but is used to meet local heat demand. However, given the assumptions related to the cost of micro-CHP26 and the need for an auxiliary gas / hydrogen boiler, the total cost of the system with micro-CHP is still marginally higher than the cost of the core Hybrid pathway (but slightly lower than the Electric scenario). Furthermore, the physical size of the some micro-CHP technologies may need to be reduced further in order for these to be deployed at scale [10].

3.3 PTH IN INDUSTRY

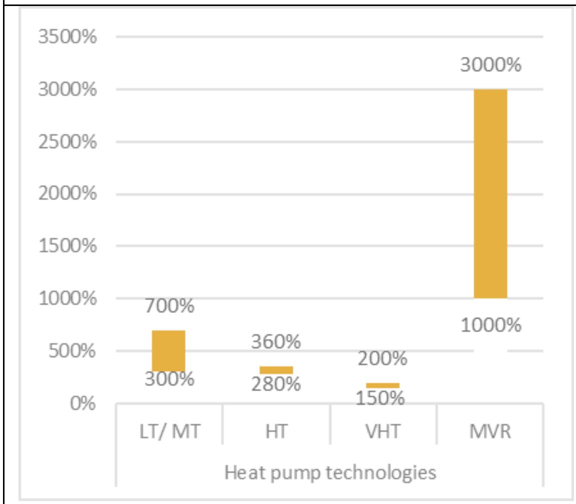
The industrial sector accounted for 25% of the EU28 final energy use in 2015 [13]. More than 70% of the 2012 industrial final energy use in Europe is estimated to be used for heating purposes [14]. The most frequently used energy carriers for industrial heating and cooling in the EU28+3 in 2015 was natural gas (39%). Electricity only accounted for 7%, which is equivalent to 173 TWh per year [15] for EU28+3.

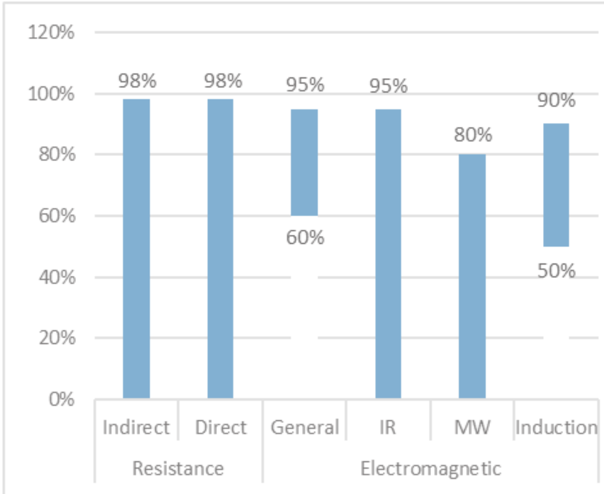
3.3.1 STATUS OF IMPLEMENTATION AND TECHNOLOGY

Table 3.2 Illustrates the key numbers for PtH in industry with regard to efficiency, TRL level, costs and deployment.

Table 3.2 Key numbers for PtH in industry

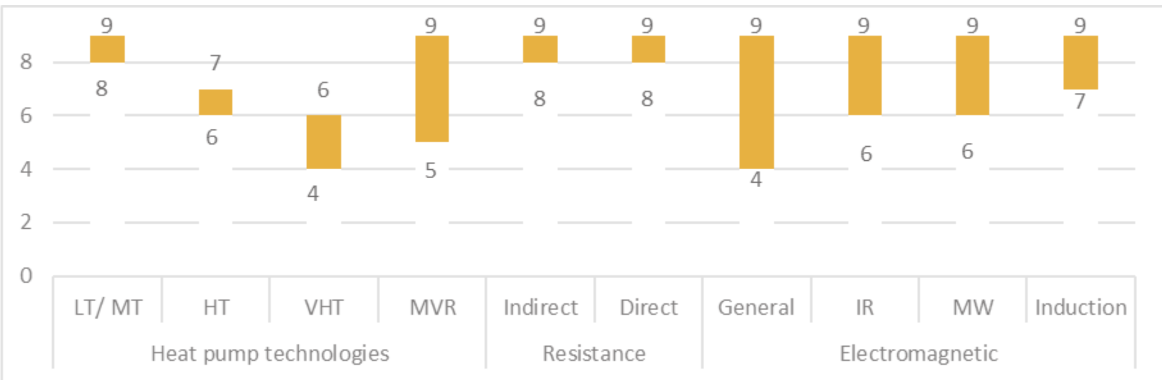
Efficiency





Overall process heating efficiency compared to combustion can often be around 150 %

TRL (1 to 9)



TECH	COST	DEPLOYMENT
PTH – Heat pumps (HP)	LT/ MT: 250 – 800 €/kW [12,13] HT: 300 – 800 €/kW [13,14] VHT: 900 – 2000 €/kW [15]	LT/MT HPs are found in several industries (e.g. food and pulp & paper) [16]. First commercial units of HT heat pumps being operated in practice [17]. VHT HP very seldom, due to economic constraints and technological development.
PTH – Mechanical Vapour Recompression (MVR)	Retrofit installation 10 to 15 years PbT. Compressor:1500 €/kW$_{electric}$ to 6500 €/kW$_{electric}$ [18]	Often used in evaporator lines in the food, chemical and paper industry.

PTH – Indirect electric heating	Electric boilers: 70 €/kW – 150 €/kW [19] (2050: 50 €/kW – 130 €/kW [19])	Sometimes used as back-up or peak boiler. Future applications in hybrid systems (fuel and electricity).
PTH – Direct electric heating	10 €/kW – 150 €/kW	Common in some processes, e.g. electric arc furnaces or specialised processes
PTH – Electromagnetic	IR-Furnace: 840 €/kW [20] IR-Dryer: 143 €/kW Microwave-emitters: 440 €/kW [20] Induction heater: 41 €/kW [20]	Common in some processes, e.g. IR drying of surfaces, induction melting and heating of metals.

N.B. LT/MT (< 100 °C), HT (100 °C to 150 °C) and VHT (> 150 °C)

Heat pumps have an efficiency above 100% as the upgrade low temperature heat with electric energy. The higher this temperature lift, the lower the efficiency (COP). Other PTH technologies convert less than 100% of the electricity input to heat, however due to more targeted heating the overall process efficiency can be increased compared to a fuel based system. Many PTH technologies have a high TRL but their integration into the industrial processes can be connected with challenges.

3.3.2 SYSTEM INTEGRATION POTENTIAL

Some electricity intensive processes are already today used for load management, such as aluminium electrolysis, limestone crushing in cement industry and electric arc furnaces in steel making [26]. These potentials of load shifting can be increased and extended with new processes using PTH. Hybrid system operation and the usage of thermal storage are further possibilities, having a large potential [27]. Most PTH technologies have the technical potential to be used to provide flexibility to the power system directly through, e.g. changes in production rate, or indirectly through, e.g. thermal energy storage. The feasibility and practicability depends strongly on the industrial sector and process. Electric boilers and induction furnaces can for example be used for flexible operation [28].

The potential for heat pumps in the EU-28 was found to cover 28.37 TWh per year of the industrial heat demand [18]. This corresponds to 1.56% of the total heat consumption and 10.41% in the analysed temperature bands. Wolf and Blesl [29] found a technical potential for the EU-28 of 476 TWh per year, which is reduced to 75 TWh per year when including economic boundaries, meaning heat generation costs must be lower than those of a fuel fired system.

3.3.3 BARRIERS AND SOLUTIONS

The adaptation of PTH technologies is limited by current economic constraints with respect to lower investment and operation costs of traditional fuel fired heating systems, such as natural gas boilers. The implementation of heat pumps, which can economically compete with fuel-based systems due to their high efficiency, is limited by the maximum supply temperature and availability of suitable heat sources. PTH technologies are in some instances perceived in industry as a risk to product quality and operability, as they may for example have longer start-up times or different heat transfer mechanisms. Demonstration projects could create interest and acceptance of PTH in industry.

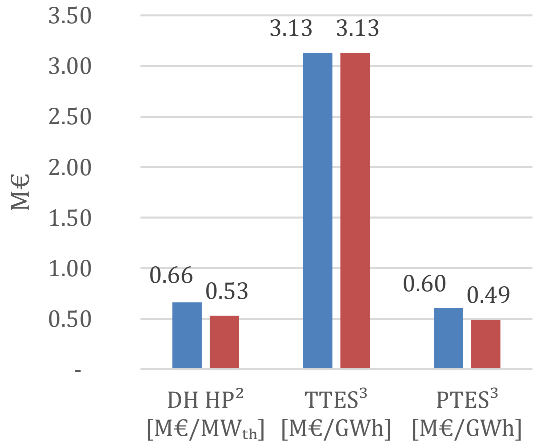
Furthermore, energy has a low priority in many industries, as the share of energy related costs of the final product can be low. Investments in other parts of the production chain can therefore be more profitable for industries.

3.4 PTH FOR DISTRICT HEATING

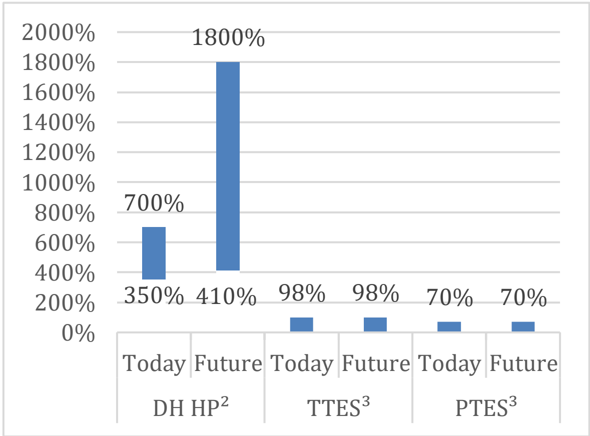
District heating (DH) is the distribution of hot water (or steam) to satisfy heating demands in a local area. Benefits include economies of scale, utilisation of excess heat and mature sector coupling.

Table 3.3 Key numbers for PtH in district heating

COST



EFFICIENCY/COP



MATURITY

HP	8-9 (Commercial with development potential)[2]
TTES	9 (Commercial)[3]
PTES	8-9 (Commercial with development potential)[3]

1: [19]. 2. [20]. 3: [21]. 4: [22].

DEPLOYMENT

HP	**1 580 MW_{heat}**	Europe[4]
TTES	**91 GWh**	Denmark, Iceland, Finland, Norway and Sweden[1]
PTES	**46 GWh**	Denmark[3]

3.4.1 SYSTEM INTEGRATION POTENTIAL

DH supplied 9% of EU thermal energy in 2015 [13] and resulted in an estimated 1.3% of total EU emissions in 2014 [35]. Heat pumps (HP) in DH systems provide coupling by consuming electricity, and flexibility by not operating during peaks. Pit thermal energy storage (PTES) and tank thermal energy storage (TTES) decouple heat generation from heat demand, unlocking DH flexibility. This ability is also seen in DH grids. TTES is useful for frequent cycling and short-term storage, enabling flexible use of HP. PTES is presently used for seasonal storage of solar heating, but can be utilised for storage of other low cost heat, e.g. HP. Studies mention 750 GWh (Europe [36]) and 1 169-1 360 GWh (Baltics+Nordics [37]) thermal storage in 2050. Another 2050-study applies a 50% DH share of heat demand, with 23.75 GW_e HP serving 20-30% of DH demand.

These HP consume 1% of total electricity demand. [38,39]. The study calculates for the EU an increased cost of 170 BEUR/year compared to an un-decarbonised scenario, and 67 BEUR/year lower cost than a decarbonised scenario without specific focus on heating and cooling [38]. Externalities not included in either.

3.4.2 BARRIERS AND SOLUTIONS

HP and PTES being at early stage of deployment adds risk. Inflexible operation arise from HPs' baseload operation due to lack of volatile prices or design limitations. HP COP depends on heat sources. PTES requires further R&D in liner materials, since these can degrade under sector coupling use-patterns. Levies on electricity can limit operation of HP. High-temperature (steam) DH will limit the COP of HP and ability for storage.

3.5 POWER TO COOLING

3.5.1 STATUS OF IMPLEMENTATION AND TECHNOLOGY

Because of a long development (historical perspective: see 8.4), the industrial refrigeration has reached a high TRL, but the continual understanding of the environmental impact and safety requirements of the used refrigerants and the development of new demands and requirements for higher performance causes further development of the systems constantly.

Process cooling constitutes a rather low share of about 1% of the final energy demand [17]. However, this is an essential need in industry, and as it is based on electricity, the primary energy consumption related to the demand is significantly higher.

[17] divides cooling demands into three temperature levels which mostly resemble demands for three different uses. These categories are used in the table below.

Table 3.4 Key numbers for PtC

TECH	TIME	TRL	EFFICIENCY	COST	CURRENT DEPLOYMENT	DESCRIPTIO N
Power to cooling – (0 °C to 15 °C)	Today	6-9	COP of 3 to 30	Similar to PtH	Vapour compression systems, potentially combined with free cooling, is the industrial standard	Mostly cooling in food industry
Power to cooling – (30 °C to 0 °C)	Today	6-9	COP of 1 to 5	Similar to PtH	Vapour compression systems, potentially combined with is the industrial standard	Mostly refrigeration in food industry
Power to cooling – (below 30 °C)	Today	3-9	COP of 0,2 to 3	Similar to PtH	Vapour compression systems, potentially combined with is the industrial standard.	Mostly air separation in chemical industry

Efficiency is defined as the Coefficient of Performance, COP, which is the delivered cooling, divided by the electricity consumption. COP is highly dependent on the demanded temperature and the ambient temperature, the heat is rejected to. Control and use of free cooling are also important.

3.5.2 SYSTEM INTEGRATION POTENTIAL

There are significant potentials for using cooling plants for integration and sector coupling. Several investigations have been made for investigating the options [177,178,179]. This may either be by using the plants as is or by including dedicated cold storage in a plant facilitating flexible consumption of electricity. Some examples are for space cooling, in retail application, in warehouses and in industry.

Cooling demands will probably increase because of increasing temperatures and higher demands for comfort by air conditioning [93], but also expansion of district cooling and industrial demands, e.g., for servers in data centres and liquefaction of natural gas are expected.

System integration may be exploited further by installation of cold storage in the plant [94].

3.5.3 BARRIERS AND SOLUTIONS

For many purposes, cooling is required at high reliability, which will be deciding for the development. Options for better control and higher efficiency or lower operating costs may provide potential for further integration with the power sector demands.

Refrigeration and cooling for process purposes may require artificial refrigeration to temperatures below ambient, but in colder periods and for higher temperature demands, cooling may be supplied by free cooling using ambient air or water, e.g., from seas, lakes, rivers or ground. Free cooling and optimal control of refrigeration systems may lower the power demand significantly for colder periods. The seasonal variation of demand is important to account for in assessment of integration potential.

Cooling is seen as an integrated part of the electricity sector, but this may result in less understanding of potentials and barriers for the integration and coupling with other sectors.

Cooling is highly diverse in nature and demand, covering a large spectrum of temperatures and capacities. Accordingly, it is not easy to provide a common solution for further integration. But, on the other hand, further flexibility may be obtained for given typical plants.

4 POWER TO MOBILITY

4.1 INTRODUCTION

Electro-mobility can be divided in different classes. First, there are the **Hybrid Electric Vehicles** (HEVs), which are types of electric vehicles driven by at least one electric motor and one additional energy converter, which is usually a conventional internal combustion engine with diesel or petrol fuel. The efficiency of its fuel-burning engine is greatest in some specific operating conditions related to speed and load and at highest efficiency, the emissions are at the lowest levels.

Another category consists of the **Plug-in hybrid Evs (PHEV)**, which have an electric drivetrain like a BEV, but also a fuel-burning engine that can recharge the batteries. Finally, there are the **battery Evs** (BEV or EV) which operate only on battery.

Following this introduction, the focus in the subsequent sections will be on power to electric vehicles (and vice-versa), in the perspective of integrating / optimising the needs of both the mobility end the power sector.

4.2 STATUS OF IMPLEMENTATION AND TECHNOLOGY

A switch from fossil hydrocarbon to renewable energy fueled transportation is paramount for a successful mitigation strategy of climate change effects. Road transport was responsible for about 19% of total GHG emissions in 2017 in the EU [104]. A switch from fossil hydrocarbon to renewable energy fuelled transportation is paramount to mitigate climate change-induced effects. Governments across different regions have been setting up support schemes and targets to accelerate electrification of transport [109] while some countries are even deploying city-wide bans for new petrol and diesel cars by 2030-2040 targeting certain municipalities [99]. For example, by 2030 diesel and petrol bans will have been implemented in London, Paris or Amsterdam, among others. In this context, the global fleet of light-duty (passenger) EVs expanded in the recent years, reaching 5 million units in 2018, while 1.2 million units were reported in Europe (0.96 million in the EU) alone in the same year [110].

This swift expansion in the recent years has been made possible through sustained development on the supply side. Auto manufacturers have been increasingly focusing on the EV segment of the market, thus fostering the development of a wide range of choices for potential customers. It is expected that this trend will continue in the near future, with auto manufacturers planning to expand their EV-based offers (e.g., Volkswagen and Hyundai target 70 and 14 EV models, respectively, in their offer by 2025). These commitments are motivated by CO2 emission- and energy demand reduction-related policies in the EU and China.

From a purely quantitative standpoint, EV rollout targets of several trans-national stakeholders reveal courageous projections towards 2050. A set of scenarios proposed by both the electricity and gas ENTSOs as technically and regulatory reasonable paths towards reaching desired climate targets suggests a swift increase of the electrical demand associated with mobility [108]. More specifically, in the context of a moderate development scenario, in which EV deployment happens together with an expansion of the vehicle fleet running on other (i.e., gaseous) low-emission fuels, more than 20 million EVs (i.e., including PHEVs) are expected on road by 2030, with additional 50 million units by 2050 in Europe alone. Under less moderate assumptions, according to which the energy demand is massively electrified and the backbone of future electricity networks will be prosumer-based, the European EV fleet is expected to reach 40 and

110 million by 2030 and 2050, respectively. A complementary analysis [107] suggests that, under coherent technological and policy developments, the EV market share in road transportation could increase from 5-10% in 2020 to 60% beyond 2030, with a strong emphasis on passenger vehicles.

Another study provides insight into the EV rollout targets of other major economies besides the EU [110]. For instance, China plans to incorporate 5 million EVs by 2020, as well as to reach a 50% market share of vehicles running on low-emission fuels by 2030. India and Japan have similar targets, with EVs accounting for 30% of all road transportation sales beyond 2030. By 2022, South Korea plans to deploy over 0.4 million EVs, while California alone plans to reach an EV fleet of 5 million by 2030. Such development is indeed impossible without a close cooperation between governments and industries in i) establishing proper regulations that foster the sustained transformation of the transportation sector and ii) providing the technologies that would make this change possible. In this context, automobile manufacturers across the world are reportedly planning on rolling out over 640 unique EV models, including 400 BEVs and 240 PHEVs [110]. Also, the battery manufacturing industry is expected to develop substantially in the decades to come, with over 370 GWh/year production capacity expected to be commissioned by 2030 around the world. Finally, the charging infrastructure requires massive up-scaling in order to facilitate the adoption of large-scale EV fleets. In this respect, 2 million charging stations are currently planned in Europe alone by 2025 (compared to today's 120 thousand) [107], with additional 3 million outside European borders by 2030 [110].

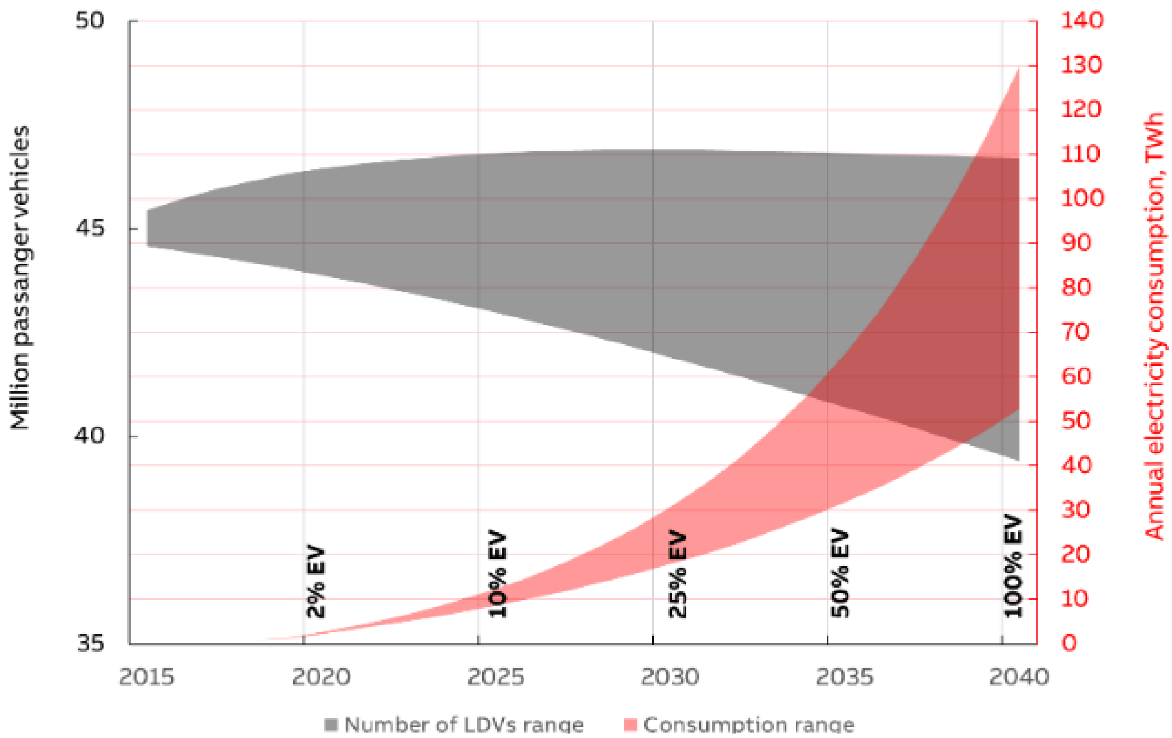


Figure 4.1: Range of possible annual electricity consumption in the German grid for different levels of electrification for LDVs [112]

A system-specific example of EV deployment policies and their subsequent impact on the power system refers to Germany. Today, the road public transportation (i.e., buses) is mainly powered by diesel fuel but several German cities have been working on development schemes to replace the traditional fleet with electrical units [111]. Figure 4.1 depicts the expected annual electricity consumption in the German grid for different levels of electrification for LDVs. The same analysis for electric buses projects just 4.510 TWh for a fully electric fleet by 2040 [112].

As a use-case, a LV residential charging is considered here; however, innovation is progressing on fast and iper-fast chargers at up to 350, 500 or even more kW, connected at MV or even HV rather than LV, and this could be the dominant model for extra-urban electric transport.

Passenger EVs typically charge in residential/commercial locations, therefore the low-voltage (LV) distribution grids will be the most impacted by a significant growth in the corresponding technology share [103]. Charging levels depend on the power supply and number of phases. Represented in Figure 4.2 are a set of default maximum power levels for existing EVs, as well as power levels meeting the SAE (i.e., Society of Automotive Engineers) standard. Today, connection to 3-phase LV grids allows charging levels to reach up to 22 kW. Fast charging (FC) stations connected directly to medium-voltage (MV) grid levels or to a LV level by using a stationary buffer energy storage are expected to reach charging capacities above 50kW (and up to 350 kW). In contrast, long parking times (e.g. > 4h) make slow charging modes a practical solution for residential/commercial LV grid connections.

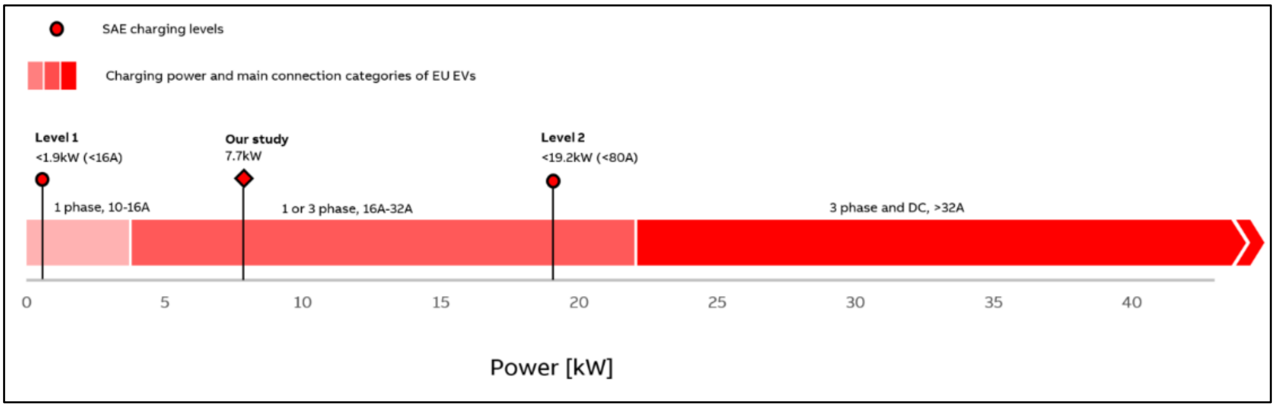


Figure 4.2: Default maximum power levels for existing EVs, as well as power levels meeting the Society of Automotive Engineers (SAE) standard

4.3 SYSTEM INTEGRATION POTENTIAL

The integration of EVs into the power system poses challenges from the perspective of power generation and transmission due to charging the battery in uncontrolled way, i.e. charging starts immediately after plugging EV to the mains at rated charger power. Driving patterns from publicly available sources allows us to estimate the potential impact. In this analysis, a fixed annual driving distance of 14’000 km is combined with the first and final departure time to home and estimated EV battery size to estimate hourly charging needs. The relevant data and driving distributions are shown in Table 8.4 of the appendix.

To demonstrate correlations between EV charging and renewable production, we consider a scenario [106] of Germany to 2040, where conventional (dispatchable) capacity has been replaced with variable renewables – wind and solar - (VRES) and traditional demand has decreased by 10% from today due to demographics and energy efficiency improvements. We also consider the countries to which Germany will be connected via transmission lines according to the ENTSO-E’s “European Power System 2040” [102].

An initial analysis of Germany in 2040 concludes that, after excluding VRES i.e. wind and solar, there will be enough generation capacity to cover the peak traditional demand. With additional EV demand peaks and variability of VRES, available dispatchable generation might be insufficient in certain hours. Power imports from connected countries would usually cover generation inadequacy but by 2040 these countries could experience similar issues. The adequacy of the grid zone depends on the amount of dispatchable generation, the availability of VRES, and changes to the electricity demand.

Illustrated in Figure 4.3 is the day containing the hour with minimum surplus power in Germany from 2017 (17/01). In 2020, installed dispatchable generation and low EV market share ensure Germany's adequacy. By 2030 the demand exceeds total production capacity at 17:00 due to an increase of EV market share together with nuclear phase-out and retirements of other dispatchable capacities. By 2040 continued retirements of generation and 100% EVs cause the deficit to grow, with significant inadequacy during two instances in the day.

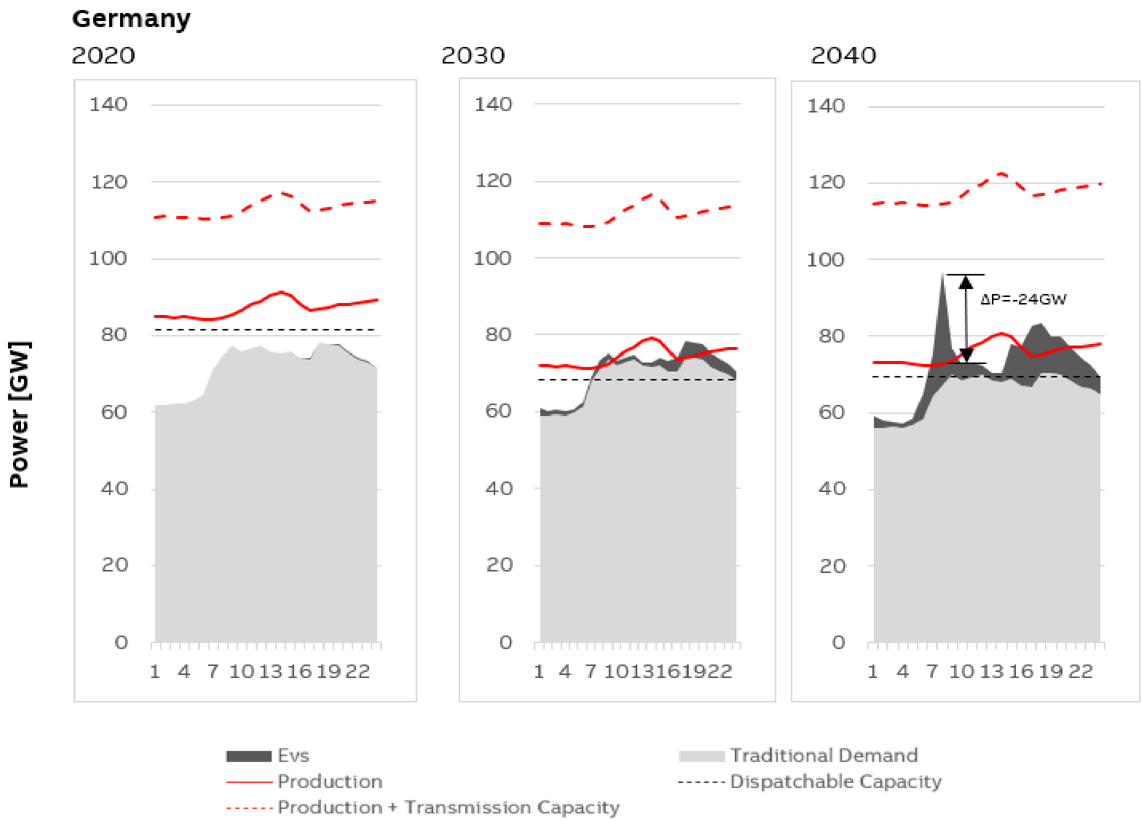


Figure 4.3: The day containing the hour with minimum surplus power in Germany from 2017

The additional EV demand creates several instances of inadequacy at 08:00 and 17:00 reaching up to 24GW. In all cases the 2040 projected transmission capacity is large enough to cover the difference, and surrounding countries would be required to export the missing power. The entire 24GW required by Germany at 08:00 is available from the United Kingdom (UK). Since ENTSO-E only forecasts 1.4GW of transmission between the UK and Germany, the transfer depends on available capacity of multiple transmission lines in the region. The UK's excess supply at 8am is due to the 1hr time difference with continental Western Europe, resulting in UK fast charging peaks occurring one hour after those in other countries. Thus, Germany's ability to balance depends on the interconnection capacity with the UK.

On the distribution level, potential problems include overloading of equipment (transformers, feeders) and under-voltage conditions. The analysis [106] presented in this report uses a benchmark low and medium voltage distribution European grid models proposed by CIGRE [98; 105] to investigate an impact of different EV diffusion scenarios for 2020, 2030 and 2040 on loading of distribution transformers as well as on feeder voltage profiles. The positions of MV and

LV distribution equipment with respect to generation and demand is illustrated in Figure 4.4. It is assumed that transformers peak load is 90% of their nameplate capacity in 2017.

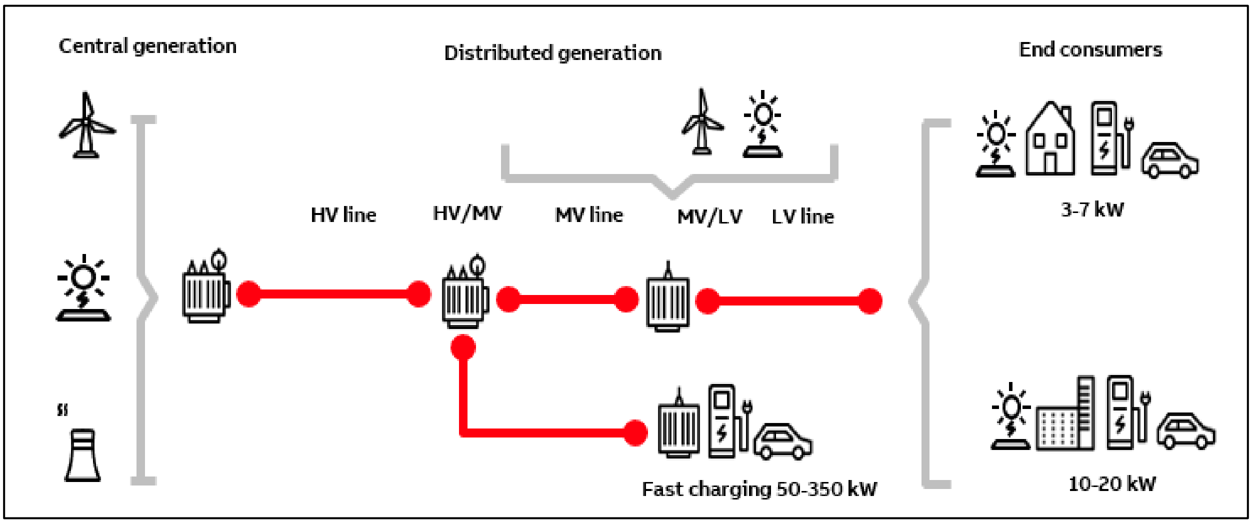


Figure 4.4: The positions of MV and LV distribution equipment with respect to generation and demand

Consider a 500kVA distribution transformer supplying a residential area, with a peak demand per consumer equal to 0.7kW. An annual reduction in traditional demand of 0.5% from 2017 to 2040, and a share of EVs growing to 100% is assumed.

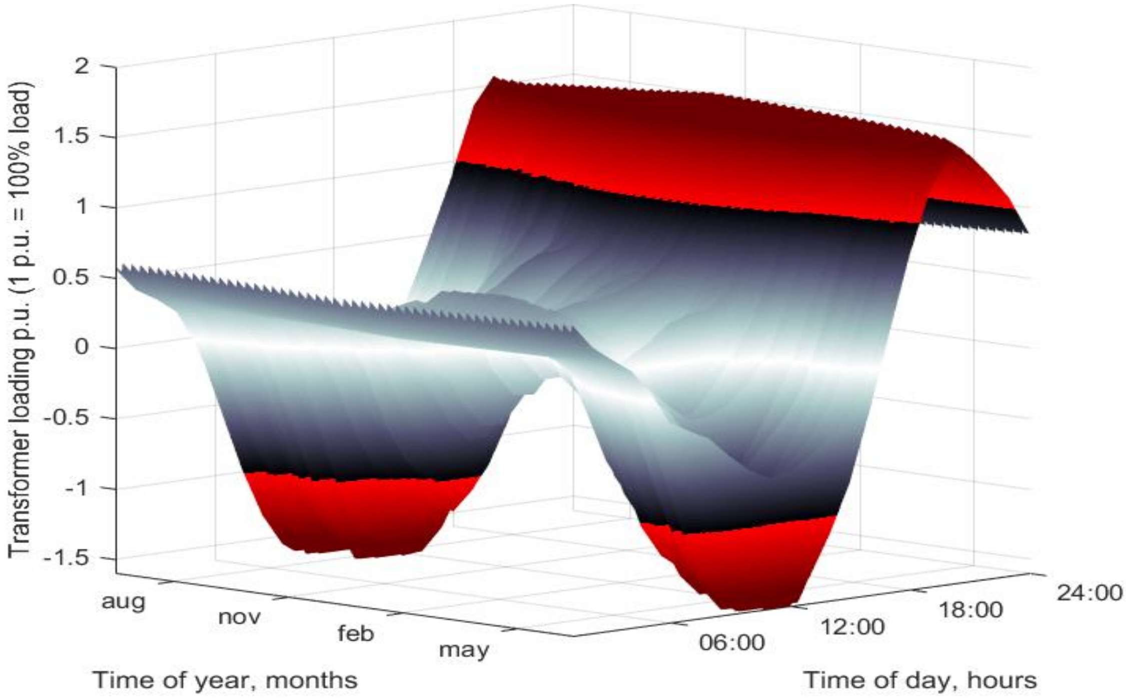


Figure 4.5: Transformer loadings across hours of the day throughout the full year

Figure 4.5 shows transformer loadings across hours of the day throughout the full year. Red indicates overloading (loading greater than 1 p.u.) in both power flow directions, while greyscale indicates operation between 0 and 1p.u. Overloading from uncontrolled EV charging reaches 67% on winter days and occurs too late in the day to be mitigated by a local solar PV production. It also demonstrates that overloading can occur in the opposite direction on summer days, where peak solar irradiance results in local generation exceeding a local demand and large amounts of solar power fed back into the grid.

Transformers for buildings in the commercial sector that offer charging stations to employees will experience an insignificant overload. This is due to several reasons. Firstly, there is complementarity between an on-site rooftop solar PV production and EV charging, both of which reach their peak around midday when most employees will be connected. Secondly, the relatively high demand of commercial sector buildings today implies that the 10% safety margin on the transformer represents significant hosting capacity.

4.4 BARRIERS AND SOLUTIONS

With increasing shares of uncontrolled-charging EVs, one of the major barriers is related to the limited hosting capacity in (LV, MV) distribution grids. In addition, the widespread integration of EVs into electric grids brings challenges due to potential flexibility issues associated with charging patterns, e.g., the battery of an uncontrolled-charging EV starts charging at rated power immediately after the EV is plugged to the grid, thus impacting locally the state of the network. Potential problems also include overloading of equipment (transformers, feeders) and under-voltage conditions. In this context, a combination of technical solutions listed in Table 4.1 are recommended to enable further EV penetration growth.

Table 4.1: Combination of technical solutions for EV penetration growth.

Digital	Hardware	
None-wire (active)		Wire (passive)
– forecasting charging needs	– distributed generation	– transformer capacity upgrade
– limit charger rating	– stationary energy storage	– feeder capacity upgrade
– delayed charging	– solid state actuators	– connection to higher voltage level
– coordination with DR	– mechanical actuators	
– smart asset overloading	– mobile energy storage	
– optimal charging		
– vehicle to grid		

Energy storage is an attractive solution for problems related to both distribution grid and generation adequacy. On the distribution level, batteries can be used to shave the EV peaks by charging during low-demand hours (e.g. during night) or locally from on-site rooftop solar PV installations. An analysis [106] demonstrates that the minimum battery size to shave themaximum EV peak in residential feeders is 1.32MWh. On the other hand, if drivers participate in delay charging, only 23% of the total EV energy demand would need to be re-distributed to prevent overloading.

In addition, the battery storage capacity within EVs offer new opportunities to handling future grid-related problems. When connected to the grid, EV battery capacity could be used to provide ancillary services (e.g. frequency regulation) or load balancing for loss of generation or VRES variability, with several pilot projects from ENEL [101] and EDF [100] already demonstrating the feasibility of vehicle to grid (V2G) as a potential path towards sustained integration of EVs in energy systems.

5 POWER TO GAS/FUELS

5.1 INTRODUCTION

Natural gas, which accounted for 22% of the world's primary energy demand in 2018 [113], is a key carrier in current energy systems. Likewise, petroleum products and all derived carriers in liquid form play a crucial role in energy systems, accounting for roughly 32% of the world's primary energy demand in 2018 [113]. These carriers are used across a wide range of applications and sectors, usually as fuels or feedstocks. Typical applications of natural gas include high temperature heat generation in industry (e.g. for calcination in the cement industry), co-generation plants, or domestic heating. On the other hand, liquid carriers are often used in transportation applications, which usually require fuels with high energy densities. The chemical industry also makes use of petroleum products and gas in the production of, e.g., ethylene, carbon black, ammonia (fertilisers), methanol and polypropylene, which may themselves serve as feedstocks in other processes.

Although the climate impact of natural gas is somewhat less pronounced than that of fossil alternatives (in particular coal, which is still predominant in several large countries), unless carbon capture and storage solutions become widely available, reliance on coal, petroleum products or natural gas cannot be envisaged as part of the ordinary energy mix in the long run, in view of climate neutrality objectives. Moreover, even though renewable energy sources can be harnessed to produce carbon-free electricity relatively cheaply, some of the aforementioned sectors and applications do not lend themselves to straightforward electrification. For instance, aviation, maritime and long-haul transportation appear particularly challenging to electrify. As a result, the production of gases and liquids with low carbon intensities and high energy densities could support ongoing efforts to decarbonize all sectors of the economy.

Power-to-gas and power-to-liquids technologies, which will be collectively referred to as power-to-X technologies in the following, have been proposed as a solution to transform electricity into gaseous or liquid energy carriers endowed with the aforementioned properties. In doing so, these technologies may facilitate the large-scale integration of carbon-free electricity produced from renewable energy sources, resulting in a tighter coupling between sectors and subsystems. They may also provide flexibility to the power system, e.g., through demand-side management or the provision of long-term energy storage. Finally, these technologies may also complement other processes that seek to produce energy carriers with the aforementioned properties from limited sustainable carbon/biomass resources.

This chapter reviews power-to-gas technologies and processes, namely water electrolysis and methanation, as well as power-to-liquids technologies, which encompass the Fischer-Tropsch process, methanol and ammonia synthesis, as summarised in Figure 5.1. Their system integration potential is also surveyed before barriers and solutions to their deployment are discussed.

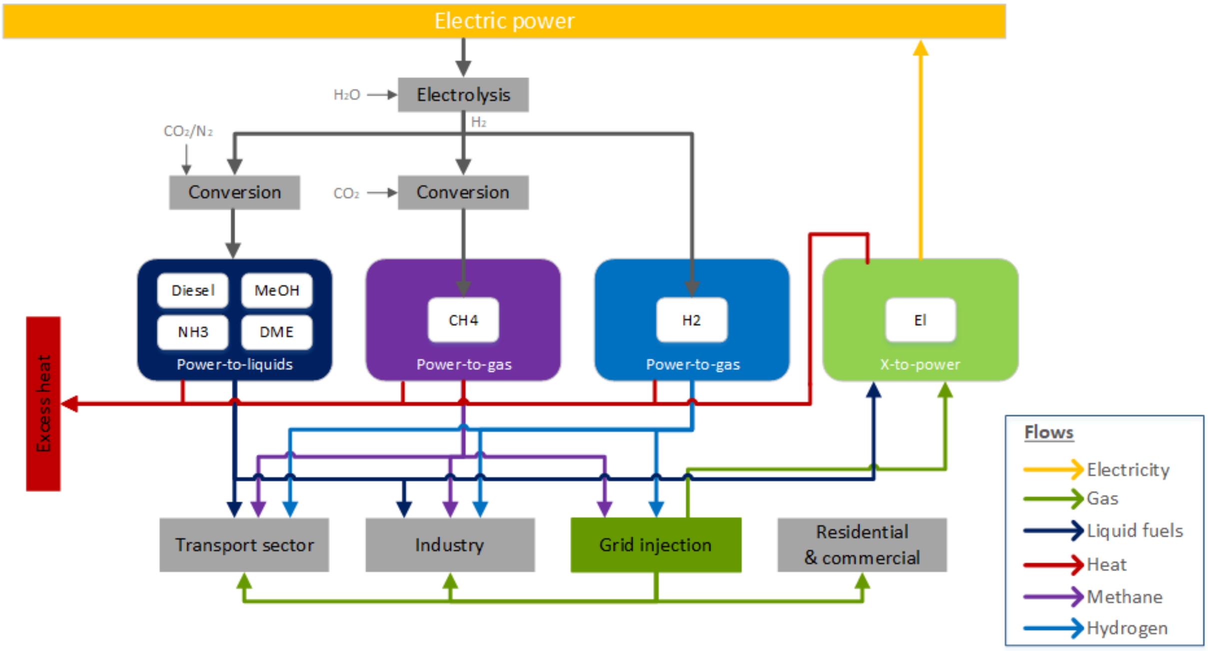


Figure 5.1: Power-to-X concept. Based on (European Commission 2018)

5.2 STATUS OF IMPLEMENTATION AND TECHNOLOGY

5.2.1 POWER-TO-HYDROGEN

This section describes technologies producing hydrogen using electricity. More specifically, the emphasis is on water electrolysis, that is, the decomposition of water into hydrogen and oxygen due to the passage of an electric current. It should be noted that these technologies will play a key role in any power-to-X strategy, as all processes and technologies further down the power-to-X chain rely on hydrogen.

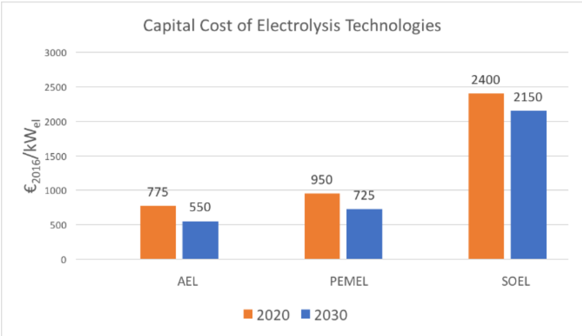
Three main water electrolysis technologies exist, namely alkaline (AEL), proton exchange membrane (also called polymer electrolyte membrane, PEMEL), and solid oxide (SOEL) electrolysers, and have reached varying degrees of maturity. Projected costs and rated efficiencies are reported in Table 5.1, based on [153] and [114]. Such cost estimates typically encompass both the electrolyser stack and auxiliary components supporting system operation, but exclude installation, grid connection and other costs relative to external compression and water or hydrogen purification units. In addition, a distinction between stack and overall system efficiency must be made, as non-negligible power losses occur in auxiliary components such as rectifiers. The maturity levels and deployment scales of different technologies as of 2019 are also summarised in Table 5.1.

Since electrolysis systems are envisioned to be integrated in power systems featuring high shares of variable renewable energy resources, their flexibility must be considered when evaluating their potential. In this respect, the load range, dynamic operation capabilities, cold and warm start-up times as well as the stand-by losses constitute key indicators. The latter are reported in the appendix for different designs, along with operating temperature and pressure ranges, estimated lifetimes and degradation rates.

Finally, it is worth emphasising that technological innovations resulting from research and development programmes will need to be combined with innovations in manufacturing processes and, more generally, a production scale-up in order to develop electrolysis technologies with the lowest costs and highest performance [153]. A comprehensive list of projects pursuing this objective can be found in [148].

Table 5.1 Key numbers for power-to-hydrogen

COST



EFFICIENCY

	AEL	PEMEL	SOEL
Stack	63-71 %	60-68 %	98%
System	46-60 %	50-60%	< 84.6%

MATURITY

AEL	Mature (TRL 9)
PEMEL	Commercial with development potential (TRL 8)
SOEL	Demonstration (TRL 6)

DEPLOYMENT SCALE

AEL	MW
PEMEL	MW
SOEL	kW

5.2.2 POWER-TO-METHANE

In the methanation process, methane is synthesized through hydrogenation of carbon dioxide. In other words, CH_4 and H_2O are obtained from H_2 and CO_2. There are two different techniques currently in use for this process, i.e., the catalytic (or chemical) and the biological methanation. The former is the more mature technology and refers to a highly exothermic thermochemical process operated at high temperatures (200 to 700°C) and pressures (1 to 100 bar), while the latter is an emerging alternative to the first option and relies on microorganisms to act as catalysts under anaerobic and aqueous conditions, at moderate temperatures (lower than 100°C) and low pressures (below 10 bar) [1340;,142]. Regardless of the technology choice, synthesis of methane from hydrogen largely depends on the availability of the entire supply chain of CO_2, including capture, transport and storage [147,156].

The current technological status of the methanation process depends on the catalyst solution used. For instance, chemical-based methanation plants have already been deployed at MW-scale

(TRL 8), with hydrogen-to-methane conversion efficiencies around 77% (in energy terms) and overall power-to-methane efficiencies reaching 54% [161]. Then, for biological methanation, research and pilot projects are currently carried out to unlock the scalability of this emerging technology (TRL 6), currently deployed at kW-scale and expected to reach hydrogen-to-methane conversion efficiencies of 80% [142,161]. The scarcity of operational commercial projects renders the estimation of associated costs highly uncertain. In this regard, reports project the costs of methanation beyond 2030 to lie between 75 and 1000 €/kW SNG, depending on the installed capacity, underlying technology, expected plant performance or served application [122,142]. Assuming a fully integrated energy system, with complete supply chain by-product (O_2 and heat in the electrolysis and methanation process, respectively) utilization, the cost of renewable methane production is expected to drop below 100 €/MWh by 2050 [142].

As of 2018, more than 30 catalytic or biological power-to-methane pilot-projects for mobile and stationary applications were operational or planned in at least nine European countries, with installed capacities ranging from kW to MW scales [140,162,133]. From a system integration standpoint, studies conducted for European energy systems of different dimensions reveal that the potential of power-to-methane being largely dependent on the availability of renewable energy resources, the commitment to strong CO_2 emissions reduction targets or natural gas market prices [121,122].

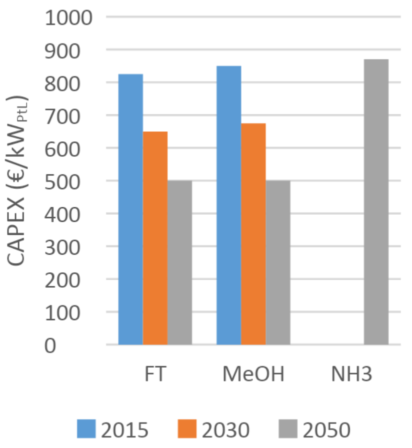
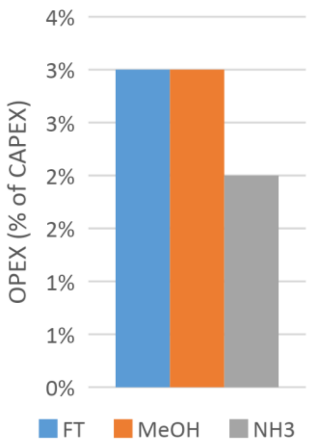
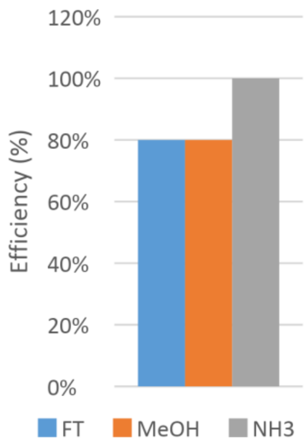
5.2.3 POWER-TO-LIQUIDS

As of 2019, liquid fuels are used in a variety of applications and sectors, and are also expected to keep a role in the future. In particular, it is likely that the industry and the transportation (especially aviation, maritime and long-haul transportation) sectors will still require fuels with high energy densities. Many types of liquid fuels are produced and used today, and a variety of synthetic liquid fuels with varying characteristics may also be needed in the future.

Different liquid fuels can be produced using various conversion technologies and processes. In particular, power-to-liquids technologies transform hydrogen produced from electrolysis into liquid fuels such as diesel/gasoil-like fuels, methanol, dimethyl ether (DME), ammonia, or ethanol, which have relatively high energy densities and can be easily stored. More precisely, power-to-liquids technologies also rely on carbon dioxide (and monoxide) to produce synthetic liquid fuels, and therefore enable carbon utilization. This section briefly reviews the prospects of technologies implementing the Fischer-Tropsch process (FT), using which liquid hydrocarbons are synthesized, as well as the methanol (MeOH), and ammonia synthesis (NH3).

Despite optimistic future cost reduction estimates [134], as of 2019, the production of renewable alternatives to fossil liquid fuels is still not cost competitive. More specifically, power-to-liquids conversion technologies are not yet mature and commercially available around the world. In fact, the performance of technologies might depend on local conditions and the most cost-effective and energy-efficient option may therefore be geography-specific (see the subsection – economic considerations). Nevertheless, the number of pilot and demonstration projects has grown in recent years, and will most probably keep increasing in the near future. Table 5.2 summarizes key characteristics of the three power-to-liquids conversion technologies considered in this section.

Table 5.2: Key characteristics of the three power-to-liquids conversion technologies

Costs		Efficiency
CAPEX	**OPEX**	
		

MATURITY

FT	Relatively established technology, however, not yet mature for power-to-liquids processes
MeOH	Relatively established technology, however, not yet mature for power-to-liquids processes
NH3	Relatively established technology, however, not yet mature for power-to-liquids processes

Examples of DEPLOYMENT

FT	Sunfire demonstration plant in Dresden [168]. Nordic Blue Crude in Norway [169].
MeOH	Carbon Recycling International in Iceland [170].
NH3	Proton Ventures – small-scale ammonia plant [171] World's first Green Ammonia power demonstrator developed by Siemens, Cardiff and Oxford University [172,173]

Note: liquid fuels production via; FT: Fisher Tropsch synthesis; MeOH: Methanol synthesis; NH3: Ammonia synthesis [159,160,161,115]

5.3 SYSTEM INTEGRATION POTENTIAL

5.3.1 OPERATIONAL CONSIDERATIONS

This subsection discusses operational aspects of electricity and gas systems coupling. More precisely, the next paragraphs explore how technology deployment choices, technical constraints, as well as scheduling and coordination procedures may affect overall system reliability, operating costs and environmental performance.

The coupling between gas and electricity systems has grown stronger in recent years [155] and may further increase in the future. On the one hand, gas-fired power plants have been increasingly relied upon for electricity generation or as a flexibility option [129]. On the other hand, power-to-gas technologies have recently been proposed as a means of facilitating renewable electricity integration and decarbonising other sectors, e.g. [114,153[119].

Owing to the maturity of the technology, the potential of gas-fired power plants is well understood. By contrast, the exact influence of power-to-gas deployment on electricity and gas systems operation is much less clear. In a purely operational context, simulation-based studies have shown that the deployment of power-to-gas technologies i) consistently reduces renewable electricity curtailment ii) in some cases, decreases gas network operating costs by reducing compressor use iii) in some cases, relieves congestion in both electricity and gas networks iv) displaces natural gas and potentially helps to decarbonise other sectors [149,158]. However, if direct injections of hydrogen are envisaged, the use of electrolysis plants may be severely constrained by strict gas quality standards aiming to safeguard the integrity of the transmission infrastructure and limiting the fraction of hydrogen in the system [149,158]. Even if these standards could be relaxed and pressure levels remained unchanged, the extent to which operating practices would need to evolve is unclear, as the lower density of hydrogen also implies a significant reduction in linepack (the volume of gas which may be maintained in a pipe during normal operation), which has typically been used for short-term balancing [167]. Hence, the deployment of hydrogen storage plants may be required to alleviate these issues.By contrast, it appears that gas networks in the UK and Belgium could accommodate direct injections of synthetic methane without any major upgrades [119,158]. Indeed, even in extreme RES and power-to-gas deployment scenarios, the latter technologies would not supply more than 10% of the daily gas consumption [119,158]. This observation mostly stems from the fact that in the countries studied, namely the UK and Belgium, the magnitude of the gas demand is routinely several times larger than that of the electricity demand. Thus, even an oversized renewable electricity generation portfolio would fall short of producing sufficient volumes of surplus electricity to convert and supply a significant share of the gas demand. Consequently, power-to-gas may only play a minor role in achieving deep decarbonisation objectives, e.g. enabling the reduction of annual carbon dioxide emissions in the UK by roughly 0.8 % [158].

Despite the strong coupling between electricity and gas carriers, the underlying systems are generally operated independently, resulting in scheduling inefficiencies, higher operating costs, suboptimal environmental performance and even threatening system reliability [115,119,138,155]. In particular, it has been shown that the joint scheduling of systems would be the most reliable and economically attractive option [129,144]. However, as of 2019, regulatory and institutional arrangements generally prevent it in most European countries. Hence, novel coordination mechanisms have been put forward, such as market-based strategies [118,130] or updated economic dispatch procedures [129,138,157,163], which aim to achieve operational performance comparable to that of joint scheduling in a decentralised fashion.

To conclude, even though power-to-gas may offer operational and environmental benefits, it is still unclear whether its overall economics warrant its large-scale deployment, and how it may compete with alternatives. These key questions are addressed in the next two subsections, which deal with economic and long-term planning considerations, respectively.

5.3.2 ECONOMIC CONSIDERATIONS:

Economic considerations regarding power-to-X conversion technologies can been seen from various perspectives, that is, from the standpoint of an individual market player seeking to maximise profits or from a system (socio-economic) perspective. Although both approaches may not yield the same results, they provide insight into the main barriers to adoption and deployment of selected technologies.

As illustrated in Figure 5.2, the economic performance of power-to-X plants as individual market players or as an integrated part of the energy system are essentially influenced by 1) techno-economic parameters, including input fuel costs, 2) the ability to valorise products and by-products across markets and sectors, and 3) market prices for the main products and by-products, as explained in the following.

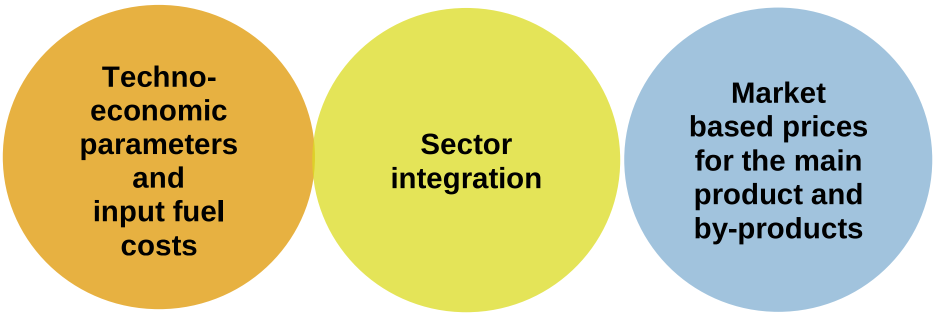


Figure 5.2: Influences on the economic performance of power-to-X plants

<u>Techno-economic parameters, and input fuel costs</u>

An overview of the key techno-economic parameters for evaluating the economic performance is provided in the section “STATUS OF IMPLEMENTATION AND TECHNOLOGY”. The economic feasibility of power-to-X conversion technologies is naturally dependent upon electricity prices, and the number of full load hours of operation. Current trends and assessments of future power system designs show that increased generation from variable renewable energy sources results in a steeper electricity price duration curve and generally more volatile electricity prices. Roughly speaking, the level of electricity prices must be sufficiently low over sufficiently long time periods, for power-to-X conversion plants to be economically viable. Such considerations are further explored in the following section “Long-Term Planning Considerations”. In addition to low electricity prices, access to low-cost water supply as well as other carriers and commodities such as CO_2 (e.g. CCS) are essential to consider when evaluating the economic performance of power-to-X technologies. Moreover, resource availability of, for example, water, carbon or nitrogen, is key and might be site or country-dependent.

Sector integration

Figure 5.1 illustrates the concept of power-to-X, and shows how it may allow for the integration of electricity, heat, and gas systems, as well as the coupling of sectors across the entire energy system. Sector coupling can improve the economic viability of power-to-X technologies, as conversion by-products such as heat can be sold to district heating networks or process industries. Oxygen or hydrocarbons may also be sold and thereby generate additional revenue streams. On the other hand, power-to-X technologies may reduce overall system costs, for example, as power-to-X technologies can provide demand side flexibility to the power system through flexible operation of electrolysers.

Market-based prices for the main product and by-products

Like input costs, market prices – and as a consequence profits or losses - for the main product and by-products are key in any economic analysis. Prerequisites are well-functioning and stable regulatory market conditions based on input costs and selling/buying prices, while on the medium term additional larger streams of revenue (e.g. feed-in-tariffs or other regulatory subsidy-like instruments of early-technology-stage support) may be needed, as for many other emerging technologies. Regarding selling prices, markets where the highest prices can be obtained for the main product and by-products need to be identified. In addition to selling the main product, and by-products such as hydrocarbons and excess heat, future markets, could potentially play a role in the economic performance of power-to-X conversion plants, for example, CO_2 markets or oxygen markets. As an overall remark, in order to have efficient market outcomes from sector coupling business cases, market prices need to be consistent across the involved different sectors.

5.3.3 LONG-TERM PLANNING CONSIDERATIONS

This section discusses the role of power-to-X technologies [132,160] in the design of optimal energy system configurations.

Gaseous or liquid fuels derived from renewable electricity could become an essential building block in cross-sectoral decarbonisation strategies. In this regard, EU-produced green hydrogen or synthetic methane can reduce fossil fuel utilization in energy-intensive sectors (e.g., mobility, industry), thus potentially mitigating the dependence on energy imports and offsetting GHG emissions [121,127,131,145]. Such avenues also appear to be cost-effective among various cross-sectoral decarbonisation pathways, mainly due to the role of renewable (or carbon-neutral) gases and liquids as alternative fuels for the heating and transportation sectors [128]. In addition, power-to-X could stimulate the development of value chains comprising multiple energy carriers or commodities, some of which are highly relevant in the decarbonisation process of the energy sector (e.g., H_2O, O_2, CO_2, low-temperature heat) [121].

Another argument for the adoption of cross-sectoral technologies stems from the ongoing transition of power systems towards VRES (e.g., solar PV, wind), whose sustained integration in electricity networks is supported by the various opportunities power-to-X technologies may unlock [125]. One such example refers to the ability to store excess renewable electricity for long time horizons (weeks, months, seasons).[119]. At the same time, conversion technologies (e.g., electrolysers, fuel cells) could gradually replace conventional power generation units in ancillary services and capacity provision mechanisms, thus assuming an active role in maintaining the reliability and adequacy of electricity networks [146]. It should be noted, however, that the infrastructure required to transport key power-to-X products or by-products, including hydrogen and carbon dioxide, is not available in most countries and retrofitting legacy infrastructure may not always be possible [167]. The development of such infrastructure should therefore be considered in planning assessments evaluating the role power-to-gas technologies may play in future energy systems.

Alternatives to power-to-X in VRES integration or GHG reduction targets also exist. On the one hand, regional electricity transmission infrastructure planning is currently the chief option to integrate large shares of intermittent generation over large geographical scopes [136]. Studies have shown that, when both alternatives are considered, deployment of power-to-X is often limited to peripheral and resource-rich areas [127]. On the other hand, it has been shown that the limited renewable potential available in some countries may severely limit the prospects of power-to-X technologies as a local solution, and other options such as carbon capture technologies may be required [121].

Similar to their operation, the long-term planning of electricity and gas systems is usually carried out separately, often resulting in technical, economic or environmental inefficiencies [154]. Yet, a paradigm shift can be observed in this regard, with national and regional stakeholders already engaged in the development of integrated analyses [135,139].

In conclusion, power-to-X technologies may play a role in the design of future energy systems relying heavily on renewable resources, but their potential is expected to be country and application-specific, suggesting that their merit should be evaluated on a case-by-case basis. An overview of various studies quantifying the potential of power-to-X technologies under different spatial and environmental constraints is provided in Appendix 7.3.

5.4 BARRIERS AND SOLUTIONS

The purpose of this subsection is to highlight and discuss barriers to the development and deployment of power-to-X technologies, as well as potential solutions. Barriers and solutions are classified into three broad categories, which encompass technical, economic, as well as legal, institutional and regulatory considerations, as detailed in the next paragraphs.

From a technical perspective, barriers appear on several levels, from individual components to their integration into larger systems. Firstly, most power-to-X technologies are not fully mature and their performance must further improve to be worth deploying and integrating on a large scale. Then, it is worth highlighting that the large-scale deployment of power-to-X technologies only makes sense if large amounts of low-cost, carbon-free, surplus electricity are available, which usually implies that technologies harvesting renewable energy resources are already deployed on a massive scale. It is also clear that some countries do not possess the renewable potential necessary to supply such vast volumes of surplus electricity, limiting the prospects of power-to-gas technologies as a local solution in such contexts. Furthermore, the appropriate infrastructure for sourcing, transporting, processing and storing some products (especially hydrogen), feedstocks and by-products along the power-to-X chain, such as water, oxygen or carbon dioxide, remains to be built. Retrofitting some legacy infrastructure could be part of the solution but also presents daunting technical challenges. Finally, unless direct air (carbon) capture technologies are deployed, the use of synthetic fuels made of carbon compounds, e.g. synthetic methane or methanol, still results in net positive carbon dioxide emissions, and therefore falls short of reducing the emissions of the sectors in which these fuels are used.

Then, from an economic standpoint, at least three barriers can be foreseen. First and foremost, the costs of technologies along the power-to-X chain remain high. On the one hand, it is worth emphasizing that both technological and manufacturing innovations as well as a production scale-up would need to be combined to achieve substantial cost reductions. On the other hand, it is still unclear whether the services these technologies may deliver are worth the continued and substantial levels of investment required for their development and deployment. Moreover, it is key to start developing applications and markets for secondary fuels and by-products early. Indeed, as an example, the first block of the power-to-X chain is water electrolysis, which produces large quantities of oxygen, and very few markets or even applications currently exist for this by-product. Likewise, developing appropriate market structures allowing power-to-gas plants to provide a variety of ancillary services to electricity or gas grids is also of paramount importance. It is also worth mentioning that some power-to-X technologies may face tough direct competition from fossil fuel-based alternatives, such as steam methane reformers equipped with carbon capture technology, which may weaken their business case.

A series of institutional and regulatory issues are expected to arise as well. More precisely, it appears that the exact status of power-to-X technologies has not yet been defined in a homogeneous fashion at EU level, which implies that it is sometimes unclear which organisations are eligible to own and operate power-to-X systems. In particular, electricity or gas transmission system operators, which may directly benefit from the deployment and operation of power-to-X systems, may not be allowed to do so themselves. More generally, the institutional arrangements defining who owns and operates various assets is a somewhat complicating factor in the successful implementation of sector coupling strategies. Indeed, in the case of electricity and gas systems coupling, in most European countries, very little coordination exists between organisations owning and operating key assets such as transmission systems. In order to improve joint system performance, closer cooperation would be required on matters ranging from short-term scheduling to long-term planning. Hence, establishing institutional and regulatory frameworks facilitating the cooperation between relevant stakeholders is seen as a key step towards the successful integration of various sectors and energy carriers, including both electricity and gas.

6 CONCLUSIONS AND RECOMMENDATIONS

6.1 DEFINITIONS AND SCOPING

EC most general definiton is: «Deep integration between demand and supply», meaning an integration between final energy demand and the suppply chain options; this is actually a more general concept of **Sector Integration**, i.e. a system-of-systems view for planning, design and operation of infrastructures and processes in order to achieve resources' optimisation and improved efficiency, through exploitation of synergies and complementarities across parallel co-existing energy sectors.

In particular, Sector Coupling aims to identify the potential and limitations of conversion technologies, and deploy in the short-medium term use-cases across adjacent industrial sectors for a cheaper / faster achievements of decarbonisation targets.

Combining the positive features of end-uses (flexible loads) and of storage devices, sector coupling consists of converting electricity into another form of energy, which can then be either:

- stored for successive re-conversion to electricity, shift in time and in some cases also in space (when being transported as molecules);
- consumed, with a beneficial substitution of other energy sources, temporarily (operational optimisation) or permanently (electrification);

transported as heat or molecules, when convenient, instead of through transmission or distribution power lines of electrons.

6.2 PROJECTS ASSESSMENT AND USE CASES

The present analysis is centered on the electricity system, which shall continue to play a pivotal role in the integrated energy systems.

Being deployed in parallel to the electrification progress in heating, transport and industry (up to doubling the electricity consumptions) and assuming that the power sector will be fully decarbonised, this would contribute to a substantial reduction in CO2eq emissions from the other sectors.

Sector Coupling can provide not only energy storage opportunities, but also other more innovative solutions to the flexibility needs of the electric system:

- Providing cheaper and/or more performing storage opportunities at multiple time scales and thereby helping to integrate variable RES;
- In particular, providing a long-term low-loss storage (seasonal), which will be one essential ingredients of future power systems;
- Optimizing the utilization and the investments in infrastructures;
- Providing an alternative transport of energy when converted in molecules (chemicals, gas, fuels).

Each use-case should be assessed techno-economically vs other available means to become a viable business case via the following steps:

- Identifying main rationale clearly, from all sectors involved;
- With specific reference to the rationale, modelise quantitatively size, performances, limits and boundary conditions, optional cases;

- Assess costs & benefits, including externalities (positive and negative, not only CO2) and possibly on life-time horizon;
- Assessment must consider conversion (double conversion if back to electricity) costs and losses in realistic duty cycles as well as proper valorisation of the perfomances;
- Compare vs the best alternative, which constitute its reference base case to become an effective business case;
- Identify barriers and conditions for its profitable deployment.

6.3 RECOMMENDATIONS

Technologies are available for making the first steps of sector coupling in all sectors, where particularly the PtH/C technologies are near commercial stage, but also EV's are well on the way, while some development is still needed to scale PtX technologies up and decrease the costs further. Some support is therefore suggested in this field.

Electrification process should be managed smartly, so as to contribute to balance and stabilise power grids, otherwise large expansion of power grids will be required with potentially stranded investments in power generation, grids and storage capacity.

The main barriers are now to be found within the regulation, starting form setting up a coordination among the separated commodities markets as well as the services markets.

Demos and pilots, on specific cases, should receive European funding support and deserve important attention in the forthcoming HorizonEurope program. RDI projects should also be incentivised by local system/authorities whenever there is a transversal portfolio of benefits. Furthermore, the demonstration projects should:

- exchange results with other projects to accelerate learning
- share data, optimisation methods/tools and results openly
- include analyses of regulation and markets to facilitate fast implementation
- involve stakeholders across sectors to increase coordination of planning, as a mean to unlock efficiently the potential synergies.

As an overall remark, in order to have efficient market outcomes from sector coupling business cases, market prices need to be consistent across the different sectors involved.

7 APPENDICES

7.1 APPENDIX – STORAGE

Overview of storage technologies

Chemical energy storage

Chemical energy storage stores energy in chemicals that appear in gaseous, liquid or solid form and energy is released in chemical reactions. Major characteristics are a high energy density and a variety of transport and storage options.

Applications:

- Seasonal ES
- Indirect electrification of aviation, marine sector and transport
- Electrochemical energy storage technologies

Electrochemical energy storage

Electrochemical energy storage covers batteries. Chemical energy is stored and converted to electrical energy and vice versa thanks to electrical reactions. You can split electrochemical energy storage into two broad categories: Classic batteries and flow batteries.

Applications:

- Electrification of the transport sector
- Stationary applications

Electrical energy storage

Electrical energy storage stores electrons. In a capacitor, the electricity is stored in the electrostatic field between two electrodes. In superconducting magnetic energy storage, the electricity is stored in the magnetic field of a coil. The energy capacity is limited but the reaction time is fast, while the power and efficiency are very high.

1) Supercapacitors:

Supercapacitors store an electrical charge in an electric double layer at the interface between a high-surface-area carbon electrode and a liquid electrolyte.

Applications:

- Suitable for high power applications
- Transmission line stability
- Tertiary frequency control
- Secondary frequency control
- Renewables intermittency smoothing

2) Superconducting Magnetic Energy Storage:

SMES stores the energy in the magnetic field of superconducting coils, exploiting the ultra-low losses of superconductors, which allows a very fast delivery of high power at high cycle efficiency even if the cooling is accounted for.

Applications:

- Pulsed power supply
- Improvement of power quality
- Voltage control
- Reactive power compensation
- Uninterruptable Power Supply

Mechanical energy storage

Mechanical energy storage combines several storage principles like the potential energy of water in hydro storage, the volume and pressure work of air in compressed air energy storage, the rotational energy of a mass in flywheels and the stored energy in cryogenic liquids.

1) Compressed Air energy storage:

Process in which energy is stored in the form of high-pressured compressed air.

Applications:

- Inertial response
- Fast frequency response
- Fast post fault active power recovery
- Dynamic reactive response
- Steady state reactive power

2) Liquid Air energy storage:

Liquid air energy storage is an energy storage technology that uses liquid air as an energy vector.

Applications:

- LAES can support renewables integration by absorbing large amounts of excess energy, thereby reducing curtailment.
- Network reinforcement deferral
- Daily-Weekly balancing
- Security of supply
- Frequency control, reserve and other ancillary services: grid stability
- Black start
- Increase flexibility of conventional power plant

3) Flywheel energy storage

This kinetic energy storage system is composed of a flywheel driven by an electrical machine able to work as a motor or a generator and some power electronics to drive the machine connecting to the electric grid or the load. When the electric machine exerts a positive torque T to the flywheel with a moment of inertia J, it increases its rotation speed at a rate of T/J, until it reaches maximum velocity, storing a given kinetic energy and getting power from the grid or the load through the power electronics converter. To release the energy, the electrical machine applies a negative torque –T to the flywheel, braking it at a rate –(T/J) and pumping the energy back to the grid or the load to which it is connected.

Applications:

- Transportation
- Grid stability
- Industrial applications

Pumped hydro storage

Pumped hydro storage is among the most efficient and flexible large-scale means of storing available energy available. Electricity storage in the form of gravitational potential energy of the water.

Applications:

- Provision of contingency reserve to restore the balance of supply and demand
- Provision of regulation reserve
- Load following
- Load shifting
- Black start
- Voltage support

Thermal energy storage

Thermal energy storage includes three types of technologies. Energy can be stored in the sensible heat of materials undergoing a change in temperature. Latent heat storage takes advantage of the energy absorbed or released during a phase change and thermochemical energy storage utilises the heat evolution of a physical process or a chemical reaction.

1) Sensible heat storage

Sensible heat storages are the most commonly deployed type of TES. The principle is to increase or decrease the temperature of a solid or liquid substance with high heat capacity to store or release thermal energy transferring the heat directly or indirectly to the process.

Applications:

- District heating
- Single building storage systems
- CSP
- Power to heat
- Power plants
- Industrial processes
- Excess heat utilisation in the industry
- Steam accumulators

- Cowper storage
- Advanced adiatic compressed air energy storage

2) Latent heat storage

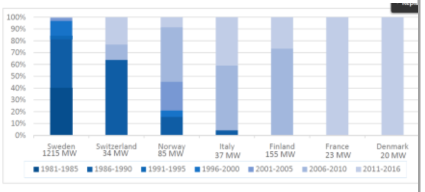
Direct systems facilitate heat transfer through intermediate contact between heat transfer fluid and the LHS material. Indirect systems separate the heat transfer fluid and storage material with a solid heat transfer border. LHS provides the possibility to store a large amount of heat at a constant temperature making it ideally suited for applications that do not provide or allow for big temperature differences.

Applications:

- Use of excess heat
- Storage of renewable heat
- Cold applications
- Stabilising temperatures of sensitive goods during transport
- Solar thermal power plants
- Steam power plants
- Thermochemical heat storage
- Thermochemical reactions based on gas-gas or gas-solid reactions use thermal energy to dissociate compounds (“AB”) into two reaction products (“A” and “B”). Upon subsequent recombination of the reactants, an exothermic reverse reaction occurs and the previously-stored heat of reaction is released
- Applications
- Solar thermal power plans
- Industrial process heat
- Building engineering
- Automotive thermal management
- Seasonal storage and peak-shifting
- Industrial excess heat
- Buffer storage in district heating
- Domestic heating, cooling and hot water applications

7.2 APPENDIX – PTH FOR DISTRICT HEATING

Table 7.1 Expanded overview of PtH in district heating

TECH	TIME	TRL	EFFICIENCY	COST	CURRENT DEPLOYMENT	DESCRIPTION
Power to heating – Heat pumps	Today	Commercial with development potential [32].	Efficiency depends on the temperatures respectively heat source – and sink. 2020: ● Ambient heat source, no dev. in supply temp.: 350% ● 40° C, reduced supply temp.: 700% [32].	2020: 0.66 M€/ MW_{heat} [32].	David et al. identified 1580 MW_{heat} in a 2017 European review.  **Figure 1.** Establishment years and capacities of heat pumps in seven countries with the greatest capacities installed and currently operating. [34]	Also called compression heat pumps. Can utilise a variety of heat sources. In Denmark, modular size of 3-5 MW_{heat} are typical. In countries with less strict HFC-refrigerant standards, size may reach >25 MW_{heat}. Flexible operation is contingent on design. [32].

-	Future	Commercial	2050: • Ambient heat source, no dev. in supply temp.: 410% • 40° C, reduced supply temp.: 1800% [32].	2050: 0.53 M€/ MW_{heat} [32].	Heat Roadmap Europe 4 applies 23.75 GW_e heat pumps with a COP of around 4, as a total for 14 EU countries in a scenario for 2050, equivalent to more than 25% of DH demand in these countries [39].	-
Thermal storage – heat accumulators	Today	Commercial	2020: Roundtrip 98% [33]	2020: 3 M€2015/$GWh_{Capacity}$ [33]	European statistics on thermal storage have not been identified. A 2015 study mentions storages from 209 DH systems in the five Nordic countries (Denmark, Iceland, Finland, Norway and Sweden) of total 1.6 Mm^3 water [23]. In a 2013-count, Denmark had a capacity of approx. 875.000 m^3 divided on 284 DH plants, equivalent to approx. 50 GWh (at 90% utilisation). Size	In these tanks, also known as sensible storages, heat is typically accumulated in water. Heat losses are calculated to 1-2.1%/week *at 90°C water temperature and 0°C outside temperature, 10 m/s wind and 300 mm insulation.* [33]

					ranged from 500-5 000 m^3. [33]. A 2016-study for Sweden shows a capacity of 899 770 m^3 in 167 DH systems [33].	
-	Future	Commercial	2050: Roundtrip 98% [33]	2050: 3 $M€2015/GWh_{Capacity}$ [33]	In the first iteration of Heat Roadmap Europe, Connolly et al. [28] apply a 2050 thermal storage capacity of 750 GWh.	
Thermal storage – pits	Today	Commercial with developmen t potential [33]	2020: Roundtrip 70% [33]	2020: 0.58 $M€2015/GWh_{Capacity}$ [33]	European statistics on thermal storage have not been identified. Germany and Denmark have deployed pit heat storages, ranging in size from <1 000 m^3 [34] to 210 000 m^3 [33]. *Typical capacities for seasonal heat storages are in the range of 50,000-500,000 m3 or 5,000-40,000 MWh at one full charging cycle.* [33].	Part of the broader category of seasonal heat storages (storages with cycles longer than a week and up to a year), pit storages are larger water reservoirs. In the same category (not treated here) are aquifer-, borehole-, and tank storages. With solar thermal as example, storage can extend from summer into autumn, and with heat pump into December. [33]. Losses after the initial two years (where the surrounding ground is

						warmed) are estimated at 0.04 K/day. [33].
-	Future	Commercial	2050: Roundtrip 70% [33]	2050: 0.47 M€2015/$GWh_{Capacity}$ [33]	No overall potentials for heat pumps or heat storage have been identified, including the *EU Reference Scenario 2016 - Energy, transport and GHG emissions - Trends to 2050* [43]. Regarding pit heat storages, Gadd and Werner [31] notes that they may see future relevance regarding especially displacement of more expensive peak load plants.	

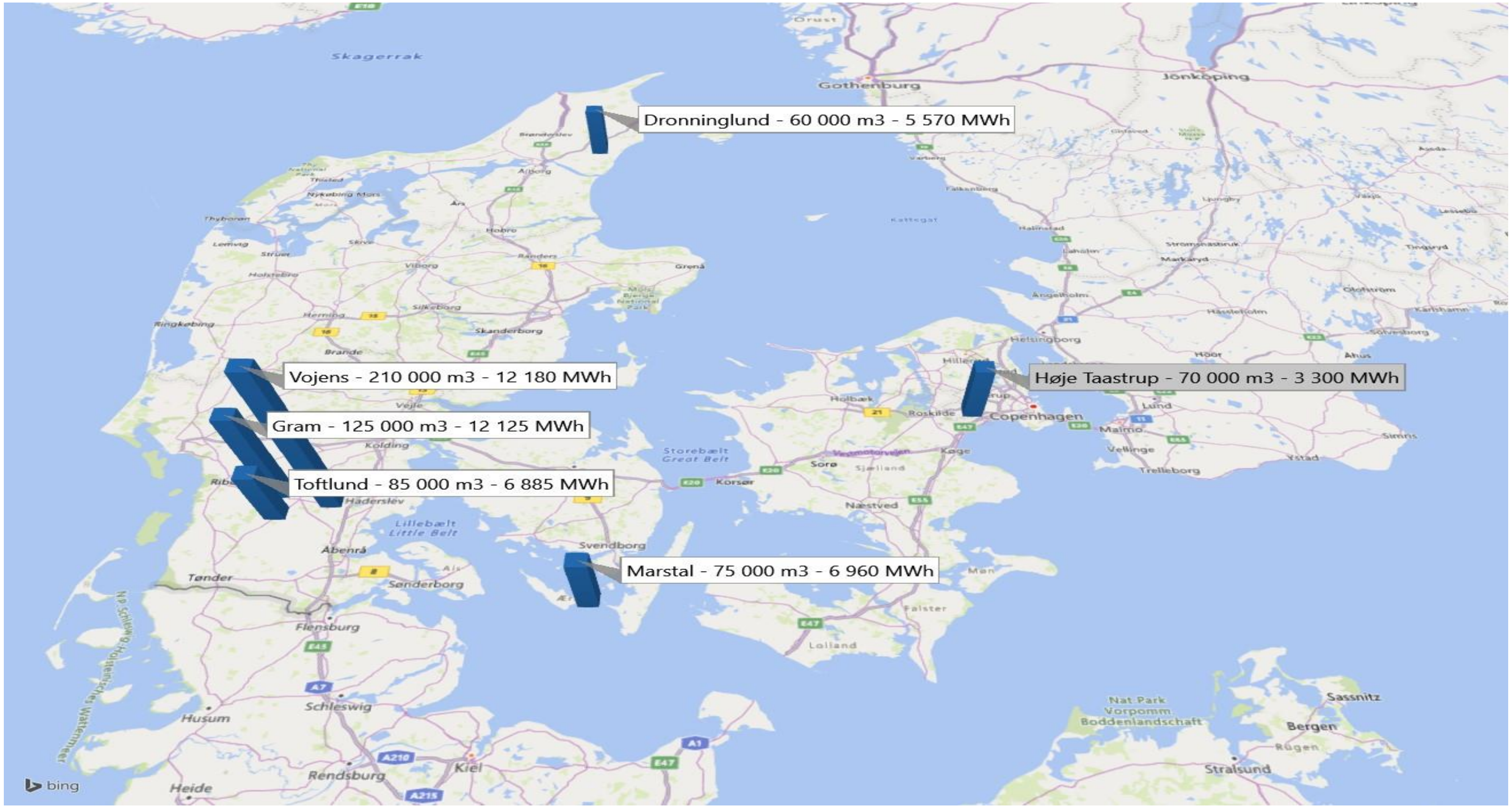


Figure 7.1: Danish PTES capacities 2019 – planned (Høje Taastrup) and existing. [29,40]

7.2.1 SYSTEM INTEGRATION POTENTIAL

Sector coupling of district heating (DH) and electricity entails a satisfaction of needs on both sides. Load variation on the heating side can be seasonal (outdoor temperature over the year) and daily (use patterns of hot water) [31].

FLEXIBILITY AND SYSTEM COUPLING

Flexible coupling between the heat and electricity systems can be facilitated through the interplay between heat pumps (HP), electric boilers (EB), combined heat and power (CHP) and thermal energy storages (TES) [31,45,46]. By shifting load, HP with TES has been shown to provide reduction in net load and a complete electricity surplus reduction in a 50% VRE supply case [47]. PtH has been shown to improve flexibility on the short term (hours-weeks) and on the long-term. The long-term is inter-annual variability of hydropower (wet and dry years), where application of PtH in wet years shows “an increase in average electricity price of 49% and an increase in the value factor for onshore wind power by up to 13 percentage points”. [48].

Flexible operation is typically driven by signals from electricity markets. Very low electricity prices drive use of EB, whereas HP due to their efficiency can operate over a broader electricity price spectrum [49]. Beyond the spot market, EB can also offer balancing services on other markets, e.g. through down regulation [50].

TES can enable plant-level flexibility towards least-cost generation capacity (e.g. during night) or towards maximisation of revenue [31,51], and concretely by displacing peak load capacity [31, 51]. TES thereby allows a decoupling of thermal load and electricity consumption for PtH – a no-regrets option [52], which provides “an almost linear influence on the flexibility of the system, and therefore financial motives” [53]. TTES allows short-term storage of hours to days, while longer-term flexibility through storage is possible through seasonal storage [50]. Charge/discharge capacity depends on design, but ranges between 0.8-5.3 MW for TTES of 3 000 m^3 is mentioned by Danish Energy Agency [33]. For PTES, capacities are in the range of 22-38.5 MW for existing stores of 85-210 000 m3 [33].

The interplay between technologies is also seen for PTES, where recent Danish cases are mostly intended to utilise solar heating – another kind of variable renewables integration than the electric. Sector coupling is still maintained, since HP can be utilised to cool the storage, whereby utilisation of solar heating panels can be expanded [54]. Since losses decrease with the surface area of the storage, large storages (with a lower surface to volume ratio than TTES) such as PTES are suitable for seasonal storage [55]. Use of PTES has gained attention within recent years, but already in 1982 a 100 000 m3 rock cavern storage was implemented in Sweden [31].

RAISING VALUE OF RENEWABLES

HP has been shown to improve the value of renewables in systems with high amount by utilising electricity for heating in periods with excess electricity in a US case [56] and for the Nordics regarding EB [48] and both EB and HP [57]. A positive correlation between wind speed and a negative correlation with electricity prices is shown for EB operation by Kirkerud et al. [48].

COST AND FUEL SAVINGS

PtH can generally reduce emissions by displacing use of fossil fuels [58]. HP can lead to cost and fuel savings in a DH system [51], by displacing generation based on natural gas [56] and fossil fuels in general [58]. A similar impact is seen with TTES [60].

DH systems can benefit from synergies among technologies, where deployment and use of technologies are not either/or, but both/and [58]. This is seen in the specific case of TTES, EB and HP, which proved to be the most profitable option compared to solutions with less technology-spread [60]. Specific conditions may result in better project economy with large-scale TES, which is not necessarily seasonal. This is seen in a Finnish case where +100 000 m3 were feasible [61].

7.2.2 BARRIERS AND SOLUTIONS

Existing DHC systems *represent largely untapped sources of demand side energy storage in many areas of the world* [62]. The barriers listed here represent part of the explanation for this.

Risk due to technological complexity of HP was in 2012 pointed out [45]. Technological development since then has mitigated this to some degree.

Inflexible operation. HP are typically dimensioned to operate at near-baseload [63], whereby abstaining from electricity consumption during price peaks is their only flexibility offering. The low marginal cost of HP will thus make it less responsive to price signals, and thus relatively less flexible than EB [45]. Another aspect of inflexibility can be the technological limitations of HP, where e.g. ramp rates can vary among HP configurations [64]. This can affect the capability of ramping and cycling of HP [65]. For PTES, further R&D in liner material (the waterproof layer), is needed to avoid deterioration caused by extended periods with 90C or higher temperature [33]. This is relevant if wanting to utilise PTES beyond seasonal solar-based storage, to other purposes such as sector coupling, where further R&D is also needed [42]. Finally, operation according to heat-load will make PtH coupled, but not flexible (as pointed out regarding the DH technology CHP by IEA [46])

Electricity grid tariffs can be decisive for the operation of PtH [60]. In one study, they affected the annual share of EB generation to vary between 2-17% [66]. Time of use tariff schemes induce more flexibility, since PtH operation can be optimised around peak prices [62, 63]. Capacity, or load demand tariff based on monthly maximum electricity load can hamper flexible use of PtH [52], resulting in less integration of wind power [49].

Taxation on electricity and fuels can affect the marginal cost between DH technologies. In the Nordics and Baltics, absence of biomass taxation along with levies on electricity use, disincentivise the use of EB [52, 67].

Physical conditions determine the available heat sources for HP throughout the year, which is relevant for their efficiency [64, 65], and thereby their flexibility and competitiveness against alternatives. TES – small and large – may be constrained by physical space available due to their significant size.

Competition to alternative DH technologies. Competition with other DH technologies, especially heat-only boilers (e.g. oil-, gas- or biomass boilers) is also a relevant barrier for PtH [48, 66]. The aspects affecting competitiveness overlaps with many of the barriers in this section, but a central one is sufficiently low electricity prices [60,63,65,69,71]

Technology cost. HP still have a development potential regarding cost [32].

Existing infrastructure determines the infrastructural context in which the technologies are functioning. For both HP and TES, high temperature need (e.g. steam) at the consumer end may be a challenge, since heat pumps are generally more efficient at lower temperature levels [72]. Furthermore, most short-term storages (typically TTES) apply liquid water [31].

Improving the business-case and the operation of PtH can be achieved by adjusting investment and operation subsidies, taxation [50, 73,74,75,77] and electricity grid tariffs [47,52,70,77,78].

7.3 APPENDIX – PTH IN INDUSTRY

7.3.1 STATUS OF IMPLEMENTATION AND TECHNOLOGY

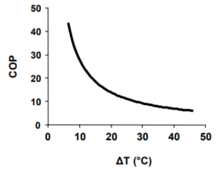
Current scale of implementation:

The most frequently used energy carriers for industrial heating and cooling in the EU28+3 in 2015 was natural gas (39 %). Electricity only accounted for 7 %, which is equivalent to 173 TWh per year [9].

Table 7.2 Expanded overview of PtH in industry I

TECH	TIME	TRL	EFFICIENCY	COST	CURRENT DEPLOYMENT	DESCRIPTION
Power to heating – Heat pumps LT/MT (< 100 °C)	Today	Commercial with development potential [19]	Depends on sink and source temperature and media. LT/ MT: 300 % - 700 %	Costs will depend on heat source and sink temperature, thermal power and industry application. LT/ MT: 250 – 800 €/kW [10,11]	Several heat pumps in industries are in operation throughout Europe [79]. LT/MT HPs are found in several industries (e.g. food and pulp & paper) [22].	Compression heat pumps using a heat source (e.g. waste heat) to supply process heat at temperatures up to 100 °C.
Power to heating – Heat pumps HT (100 °C to 150 °C)	Today	Commercial with development potential [19]	Depends on sink and source temperature and media.	Costs will depend on heat source and sink temperature, thermal power	Some heat pumps installed as part of development and demonstration projects and first commercial	Compression and mechanical vapour recompression heat pumps using a heat source (e.g. waste heat) to supply process heat at temperatures up to 150 °C.

			HT: 280 % - 360 % [19,20]	and industry application. HT: 300 – 800 €/kW [19,20]	units in operation [19,20,23,80].	
Power to heating – Heat pumps VHT (> 150 °C)	Today	Research and Development potential	Depends on sink and source temperature and media. VHT: 150 % - 200 % [21]	Costs will depend on heat source and sink temperature, thermal power and industry application. VHT: 900 – 2000 €/kW [21]	Currently in the research state while some components readily available [21].	Compression and mechanical vapour recompression heat pumps using a heat source (e.g. waste heat) to supply process heat at temperatures above 150 °C. Open and closed cycle heat pumps.
Power to heating – Mechanical Vapour Recompression (MVR)	Today	Commercial	Very high efficiencies in evaporator systems (COP of 10 to 30) [81].	Investment costs can be high for the compressors/ fans due to high volumetric flowrate, compared to ejectors. Retrofit installation have	Often used in evaporator and distillation systems in the food and chemical industry.	Mechanical vapour recompression is the technique of increasing the pressure and thus also the temperature of waste gases, thereby allowing their heat to be re-used [18,78].The compression is done in electricity driven compressors.

				typically a payback time of 10 to 15 years PbT. Compressor costs around 1500 €/kW$_{electric}$ to 6500 €/kW$_{electric}$ [24]		
Power to heating – Indirect electric heating	Today	Commercial	High conversion efficiencies close to 100 %	Costs for electric boilers are for large units (>10 MW) comparable to gas fired boilers. For smaller units electric boilers are more expensive [25]. Electric boilers: 70 €/kW – 150 €/kW [25] and are expected to fall to 50 €/kW – 130 €/kW [25].	Electric boilers are often used as back up or peak units. Can be used in hybrid systems.	Electric and electrode boilers heating an intermittent heat carrier.

Power to heating – Direct electric heating	Today	Commercial	High conversion efficiencies close to 100 %	Costs for direct electric heating are relatively low, compared to other PtH technologies.	Several industries use electric heating for different processes. Several industries could convert to electric heat in the heavy industry [83]	Direct heating of the material, through resistance flow heaters, electric arc furnaces and others.
Power to heating – Electromagnetic	Today	Commercial	The efficiencies (electricity to radiant heat) are in the range of 60 % to 95 % [26]. Near infrared reaches up to 95 % in drying and baking applications. Microwave has efficiencies of 80 % and induction heating	IR-Dryer for paper in the size of 21 MW is estimated to cost 143 €/kW. This is around 20 % cheaper then commonly used steam dryers. The savings of total system costs are around 45 % [26]. A microwave-assisted kiln is estimated to cost 4 % than a gas-	Electromagnetic technologies are common in some industrial applications (e.g. heating of surfaces with infrared and induction heating for melting and heating electrically conducting metals). Their application could however possibly be extended to many other industrial processes. In particular, drying and	Electromagnetic heating technologies use wavelengths in the electromagnetic spectrum (e.g. infrared, microwave, radio frequency) to generate heat in a target material. They require less energy as they directly heat the targeted medium directly instead of a medium transporting the heat (e.g. air in fuel combustion). Electromagnetic technologies are more rapid and allow for faster processing.

			between 50 % and 90 % [26]. However the overall process heating efficiency compared to combustion based once are often higher, leading to energy savings of up to 60 %.	fired kiln. The microwave emitters and their installation account for approx. 35 % of the costs.	heating processes appear relevant.	

- High temperature heat pumps: Market overview, state of the art, research status, refrigerants, and application potentials [19]

- Annex 35 Application of Industrial Heat Pumps (Market, barriers, Project examples) [22]

Table 7.3 Expanded overview of PtH in industry II

TECH	TRL	EFFICIENCY	COST	DEPLOYMENT
PTH – Heat pumps (HP)	LT/ MT: Commercial with development potential. HT: Commercial with development potential. VHT: Development and research potential.	LT/ MT: 300 % - 700 % HT: 280 % - 360 % [15,16] VHT: 150 % - 200 % [21]	LT/ MT: 250 – 800 €/kW [10,11] HT: 300 – 800 €/kW [19,20] VHT: 900 – 2000 €/kW [21]	LT/MT HPs are found in several industries (e.g. food and pulp & paper) [22]. First commercial units of HT heat pumps being operated in practice [23]. VHT HP very seldom, due to economic constraints and technological development.
PTH – Mechanical Vapour Recompression (MVR)	Commercial	1000 % to 3000 % [81]	Retrofit installation 10 to 15 years PbT. Compressor:1500 €/kW$_{electric}$ to 6500 €/kW$_{electric}$ [24]	Often used in evaporator lines in the food, chemical and paper industry.

PTH – Indirect electric heating	Commercial	Boilers: 98 - 99 %	Electric boilers: 70 €/kW – 150 €/kW [25] (2050: 50 €/kW – 130 €/kW [25])	Sometimes used as back-up or peak boiler. Future applications in hybrid systems (fuel and electricity).
PTH – Direct electric heating	Commercial	Close to 100 %	10 €/kW – 150 €/kW	Common in some processes, e.g. electric arc furnaces or specialised processes
PTH – Electromagnetic	Commercial, development and research potential.	General: 60 % - 95 % IR: up to 95 % Microwave: 80 % Induction: 50 % - 90 % [24] Overall process heating efficiency compared to combustion one around 150 %	IR-Furnace: 840 €/kW [26] IR-Dryer: 143 €/kW Microwave-emitters: 440 €/kW [26] Induction heater: 41 €/kW [26]	Common in some processes, e.g. IR drying of surfaces, induction melting and heating of metals.

7.3.2 SYSTEM INTEGRATION POTENTIAL

Overall implementation potential:

The potential for using heat pumps in the EU industry was analysed by [20]. Within the process heat temperature bands of interest, the total annual heat consumption in industries in the EU was found to be 192.36 TWh per year between 100°C to 150 °C and 80.11 TWh per year in the range of 150 °C to 200 °C. The highest heat consumption in the lower temperature band in absolute values is in food industry, representing 35% of it heat consumption. The available heat that can be used by the heat pumps was found to be 21.66 TWh per year. As a result, heat pumps found to be able to cover 28.37 TWh per year of the EU-28 industrial heat demand [20]. This corresponds to 1.56 % of the total heat consumption and 10.41 % in the analysed temperature bands in the EU-28.

The potential use of industrial heat pumps in the EU-28 was further analysed by Wolf and Blesl [30]. They found that there is a technical potential of covering 15 % (476 TWh per year) of the final industrial energy with heat pumps and, if economic boundary conditions are taken into account, the potential was 2.3 % (75 TWh per year).

Several works analysed the potential of industrial heat pumps in Germany [29,80,84], which is the country with the highest industrial heat use in the EU [9]. Wolf et al. [80,84] estimates that with existing heat pump technologies 14 % of the German heat use in the industry (including space heat and hot water) could be provided. If high temperature heat pumps are introduced the total potential is increased to 32 %, equivalent to 166 TWh of heat provided through heat pumps.

The overall Power-to-Heat potential in the industry in Germany was analysed by Gruber et al. [29] for the year 2008. Out of the total process heat demand of 470 TWh per year, 62 % of the demand can be directly supplied through electric technologies. In the analysed heat pump scenario, a reduction of final energy use of 13 % is further obtained through power to heat technologies. Here heat pumps supply process heat of an additional 45 TWh per year and 130 TWh per year are supplied through other Power to heat technologies.

The reviewed studies agreed that the highest potential for heat pumps can be found in food and chemical industry.

Potential benefits of Power-to-heat for the industry:

There are several benefits for industries to convert their fuel based heat supply to Power-to-heat technologies [26,29,85]:

- Energy efficiency. Many Power-to-heat technologies allow for a reduction in final energy use. These reductions can be obtained through (i) reduced heat losses (no flue gases from fuel combustion), (ii) efficient heat transfer between heat source and product (e.g. electromagnetic) leading to reduced heat losses and (iii) efficient heating and use of excess heat through heat pumping (e.g. heat pumps and MVR)

- Productivity. In some applications, Power-to-heat technologies allow for an increase in productivity (opening of bottlenecks) as electric heating can be considerable faster. Induction and infrared heating take considerably less time for completing a heating task than a gas-fired system.

- Product quality. Increase in product quality possible in some processes through Power-to-heat technologies. Electric heating can be more precise in temperature, can heat more uniformly and direct heat more precisely.

- Cost-reduction. Power-to-heat has the potential to reduce operating costs in the industry. The hybrid operation of PtH technology and conventional energy source can in the short-term lead to economic benefits. Profits from time-dependent price arbitrage between electricity and conventional energy carriers (mostly natural gas), and from additional value in the electricity system such as the balancing market and ancillary services is possible.

- Sustainability. By converting from fossil fuel combustion to Power-to-heat the industry can immediately reduce the CO2 emissions if the electricity originates from renewable sources. This can help to reach consumers who demand clean products.

<u>Potential benefits of Power-to-heat in the industry for the power sector:</u>

The implementation of Power-to-heat technologies in industries can provide benefits to the power sector.

- Flexibility. The industry can provide flexible capacities through electrification of its heat demand. This flexibility can be achieved by (i) the storage of renewable electricity when prices are low (e.g. in chemical products, intermediate products such as hydrogen, or as heat or cold), (ii) using the electricity when prices are higher (e.g. increasing production), (iii) reducing demand when prices are high and ramp up processes when prices are low and (iv) hybrid operation of power-to-heat technologies with conventional heat supplies. The supply flexibility to power systems is technically possible with most PtH technologies, however a limited number of industries for practical flexibility [28,29].

- In [86] it was estimated that energy intensive processes (e.g. Aluminium, steel, cement, chloride and paper production) have flexibility potentials of 25 % to 100 %, meaning that between 25 % to 100 % of the load can be reduced.

<u>Summary of studies relevant to Power-to-heat in the industry:</u>

In the following a list of studies is given, which have relevance to the current work.

- Potential for using waste heat in heat pumps in the European industry [19]

- Decarbonising industry in Sweden an assessment of possibilities and policy needs [87]

- Electrification in the Dutch process industry (Electrification technologies, potential and market drivers for electrification, main barriers for development) [85]

- Potential for Power-to-Heat in the Netherlands [88]

- Decarbonising the energy intensive basic materials industry through electrification e Implications for future EU electricity demand (Potential for electrification of steel, cement, glass ammonia etc. industries in the EU, Cross-cutting technologies for these industries) [83]

- The transition of energy intensive processing industries towards deep decarbonisation: Characteristics and implications for future research (policy recommendations, drivers and bottlenecks, TRL) [89]

- Industry's Electrification and Role in the Future Electricity System: A Strategic Innovation Agenda (Some barriers and drivers, Opportunities for electrification, Impact on power system) [90]

- Zero Carbon Industry Plan: Electrifying Industry (Barriers, Benefits, Technologies, Cases, Australia) [26]

- Industrielles Power-to-Heat Potenzial (Technologies, Potential, Germany) [29]

- Concepts and pathways towards a carbon-neutral heavy industry in the German federal state of North Rhine-Westphalia [91]

7.3.3 BARRIERS AND SOLUTIONS

<u>Barriers to the implementation of Power-to-heat technologies in the industry:</u>

There are several general barriers for Power-to-heat technologies in the industry, which are also found for other technologies in the field of energy efficiency. A lack of knowledge about technologies and required process characteristic, as well as a lack of awareness with respect to energy use can prevent industries to invest [22,92].

A summary of barriers specific to Power-to-heat technologies in the industry, alongside development needs to overcome those, can be found in [85]. Some of the most important barriers are given in the following.

- Power-to-heat technology readiness

o Research and development for high and very high temperature heat pumps as current technology limitations restrict the application field.

o Demonstration projects of some Power-to-heat technologies in some industrial sectors.

- Imperfect information and behavioural barriers

- Willingness to adapt new technologies especially when directly impacting the product (e.g. electromagnetic)
- Lack of information about new technologies

- Economic barriers

- Some technologies (e.g. Heat pumps) have high investment costs compared to oil and gas burners [22]. Some PtH technologies can however be installed modular and thereby spreading investment costs [26].
- Ratio between electricity price and price for other fuel-based energy carriers unfavourable for Power-to-heat.

Solutions to promote Power-to-heat in industries:

Several actions which should be undertaken to increase electrification in the industry are given here [26, 85].

- Demonstration projects in relevant industries and of relevant technologies
- Promote technologies and benefits of Power-to-heat to industries

7.4 APPENDIX – POWER TO COOLING

Cooling and refrigeration may be the prime example of electrification. Early refrigeration was done by harvesting and storing ice from winter and colder regions. Around the beginning of the twentieth century artificial refrigeration was implemented in industry, still in the form of producing ice for cooling and keeping cold [174]. This explains the measure of capacity *Ton of refrigeration,* which is still used sometimes and measures the tons of ice a refrigerating machine could produce in 24 hours. Refrigeration was done either by heat-driven absorption-based units or by gas compression, which used either pure gas cycles or the vapour compression system mostly used today. However, even if vapour compression machines were used, electrification required electric motors and electricity supply, which was developed during the first decades of the century [175] [174]. Since then the conventional refrigeration and cooling in industry has been electrified to large extent, while heat-driven systems do still have some use in specific areas.

7.5 APPENDIX – MOBILITY

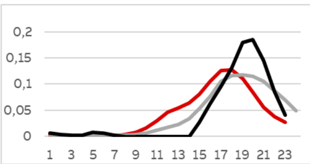
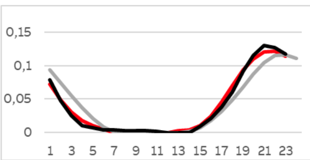
The history of electric vehicles (Evs) finds its starting point in the year 1830 when Joseph Henry introduced the first DC-power motor and several inventors in Hungary, in the Netherlands and in the U.S. started building their prototypes of small Evs. Hence, remarkably, the first cars ever developed were electric.

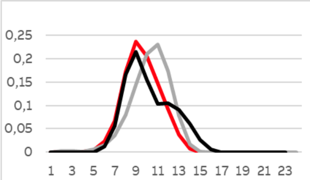
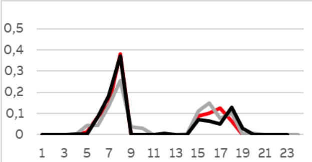
Research and development on Evs continued and intensified when, in 1874, David Salomons successfully built a rechargeable battery-powered EV. Then, English inventor Thomas Parker built the first practical production EV in London in 1884.

The impressive research and development on Evs continued through to the early 1900s, until 1908 when Ford introduced the Model-T, which delivered a significant blow to Evs due to the high driving range and affordability that it had. With the invention of the automobile starter motor, the need for operating a hand-crank to start the internal combustion engine (ICE) vehicle was gone. Hence, from 1910 onwards a decline in Evs started being observed with gasoline cars radically taking over due to their low cost (caused partially due to mass production), supported also by a low price of oil. Another reason why the fossil-fuel powered cars won the competition was due to poor battery technology as Evs had low range and could not travel long distances that could be reached by gasoline cars, while charging them took much longer than refuelling gasoline cars.

In the year 1969, the rising gas prices created renewed interest in the development and use of Evs, which was reflected in governmental bodies recommending the use of Evs as a means also to reduce air pollution. This started an era of intensive research and development on Evs. The first EV debuted in 1972 (BMW 1602E type), which included a lead-acid battery on a 32kW motor. In 1996, General Motors (GM) released the EV1, which was an EV that could travel 80 miles based on lead-acid batteries. In the late 1990s, several manufacturers, such as Honda, Ford, Nissan and Toyota, collaborated with research institutions and further expanded on research on battery technology. In 2006, Silicon Valley start-up Tesla unveiled the Tesla Roadster that was the first EV with a range that extended 200 miles using a 53 kWh battery. In 2010, Nissan begun sale of the LEAF, which had 100-mile range on a 24 kWh battery and became the most sold EV of all time. In 2011, sales of Evs intensified based on massive drop in the price of EV batteries, leading many 100% electric and plug-in Evs being on the market from a wide range of companies such as BYD, BMW, Cadillac, Fiat, Kia, etc.

Table 7.4: Driving profiles.

Charge at	Daily charging profile	2020	2030	2040
Average consumption (kWh/100km)		20	15	10
Average battery size (kWh)		50	75	100
Home daily: the car is plugged in to the power socket in the house or garage when arriving home from work		90%	60%	25%
Home twice a week: if the fleet consists of EV with larger driving range, and		9%	25%	25%

charging is not needed on a daily basis				
Work daily: the car is daily plugged in at the workplace when arriving work from home.		0.8%	10%	15%
Fast when reached 25% state of charge (SOC): fast charging is only used when the battery is down to 25% SOC. Battery size and efficiency depend on year.		0.2%	5%	35%

7.6 ECONOMIC & ENVIRONMENTAL IMPACT OF A EUROPE-WIDE EV ROLLOUT – A WHOLE-ELECTRICITY SYSTEM ANALYSIS

(IMPERIAL COLLEGE LONDON: G.STRAB, S.GIANNELOS)

European Union has adopted ambitious targets in terms of mitigating climate change through reducing emissions of greenhouse gases (GHGs). The study “Roadmap 2050: a practical guide to a prosperous, low carbon Europe”, initiated by the European Climate Foundation (ECF), derived the implications of this target for European industry and in particular for the power sector, showing that the transition to a fully reliable, fully decarbonised power sector by 2050 is a pre-condition for achieving the 80% economywide emissions reduction target [].

Imperial College London [176] also has conducted work on the application of a novel whole-system analytical framework to understand the simultaneous impact of demand for EV charging on the operation of the electricity system as well as the required investment into generation, transmission and distribution infrastructure. Specifically, the analysis conducted estimates the economic and environmental impact of a Europe-wide EV rollout on the operation and design of the European electricity system considering the 2030 horizon.

The scenario used for calculations is based on the 2030 European system characterised by high share of renewable sources, which contribute to electricity supply with about 60%.

Sizes of European passenger vehicle fleets are estimated based on actual European car density data, while the analysed levels of EV penetration in 2030 were 5% (Low), 15% (Medium) and 30% (High). This covers a broad range of projected EV penetrations, where 30% can be considered as an extremely high penetration from today’s perspective. Individual systems studied for the impact of EV deployment included: 1) Spain, 2) Italy, 3) Germany and Denmark and 4) UK and Ireland.

The impact of EV rollout is assessed using advanced whole-electricity system modelling framework capable of assessing the impact of Evs on different segments of the electricity system, simultaneously considering distribution network, transmission network and generation system, across the range of time horizons from real-time system balancing to investment time scale.

Key findings of the analysis are as follows:

- The incremental cost of supplying EV demand is a function of EV charging control strategies. In the uncontrolled case (i.e. with no smart EV demand shifting or ancillary service provision), the incremental annualised cost of electricity supply per EV is around €200/EV/year for EV penetration levels between 5% and 30%, and is relatively robust across all four analysed systems (within ±10% around €200/EV/year, increases slightly at higher penetrations). As illustrated in Figure E.1, the dominant component of additional cost is the OPEX increase, followed by increases in distribution and generation CAPEX driven by disproportionately high increase in peak demand, and only slight changes in additional transmission CAPEX.
- If there is an opportunity to control the shifting of EV demand without compromising the users' ability to make their journeys, this smart scheduling significantly reduces the incremental cost to supply EV demand. As shown in Figure E.1, the highest incremental cost levels with smart scheduling are observed in the German-Danish system (between €113 and €146/EV/year), while in the other three systems this was between €55 and €110/EV/year across the analysed cases (higher values generally correspond to higher EV penetrations). The largest contribution to cost reduction is through OPEX savings (i.e. improved generation efficiency), followed by distribution and then generation CAPEX savings.

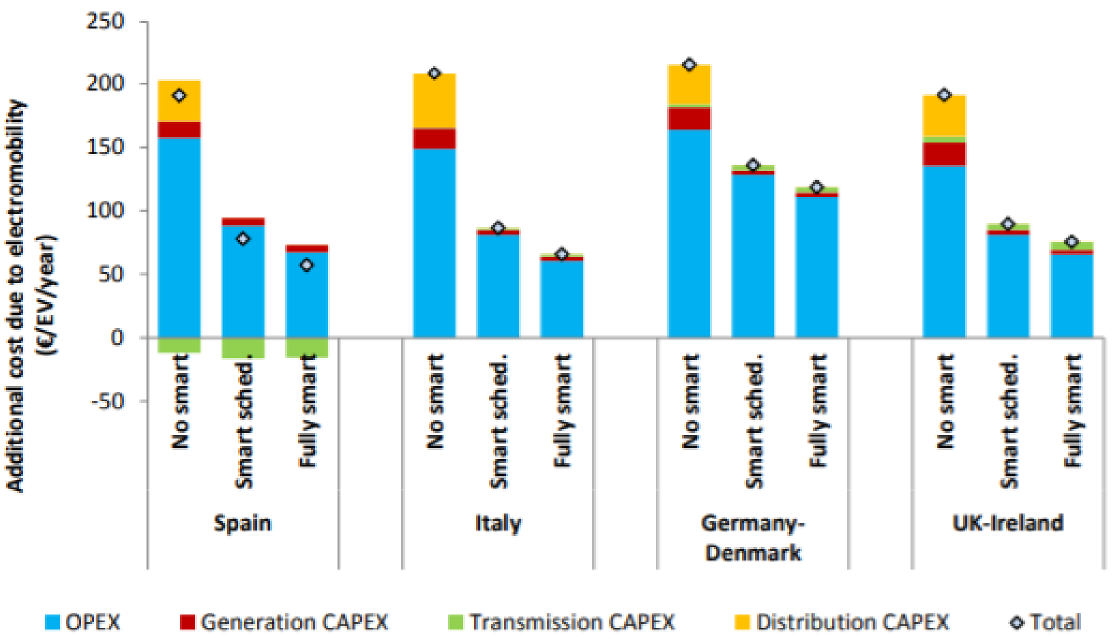


Figure E.1. Additional cost of supply EV demand in 2030 across four systems (Medium EV penetration)

- The value of Evs providing frequency regulation (FR) is also found to be considerable. The combined participation in smart EV scheduling and FR provision reduces the cost further to between €97 and €134/EV/year in the case of Germany and Denmark, and €32-94/EV/year for the other three systems (higher values again correspond to higher EV penetrations). Figure E.1 shows that the cost savings generated by FR provision are almost exclusively made up of OPEX savings from displacing part-loaded conventional generation as FR providers.

- The analysis of CO2 emissions from electricity systems shows that smart EV demand scheduling and FR provision can also result in greatly reduced carbon emissions from electricity sector, the magnitude of which depends on the system properties. Carbon footprint of supplying electricity to Evs with no smart EV control varies between 320 kgCO2 in the UK-Ireland system (equivalent to 26 gCO2/km for an average annual distance travelled) and 415-497 kgCO2/EV/year (34-40 gCO2/km) in the other three systems. Implementing the fully smart EV control (both scheduling and FR provision) reduces the carbon emissions to about 90 to 340 kgCO2/EV/year (about 7- 21 gCO2/km) in all systems except the UK-Irish one, where we observe the drop in incremental emissions to the level of –40 to 25 kgCO2/EV/year (about –3 to 2 gCO2/km) i.e. the carbon emissions from the electricity system may even decrease as the result of integrating smart Evs (before any emission offsets in road transport are considered). Emissions in both smart and non-smart cases are significantly lower than tailpipe CO2 emissions associated with ICE vehicles in the EU (127 g/km for new vehicles in 2013, with the target to reduce this to 95 g/km by 2021). We further find that smart EV management approaches also have the potential to deliver considerable reductions in curtailment of intermittent renewable output such as solar and wind. Figure E.2 presents the carbon emissions associated with supplying EV demand (left), as well as the impact of EV deployment on the expected level of curtailed renewable output (right).

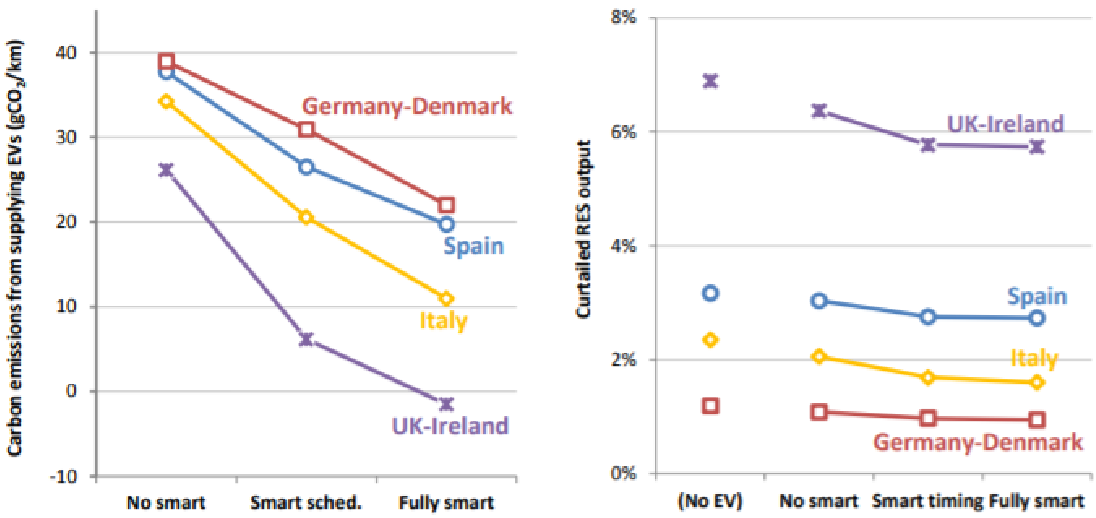


Figure E.2 Carbon emissions driven by supplying EV demand (left) and renewable output curtailment (right) across four systems (Medium EV penetration)

The results presented in the report suggest there are significant economic opportunities for flexible EV charging that can substantially reduce the system integration cost of EV deployment, as well as mitigate the environmental impact in terms of additional carbon emissions from the electricity sector. In other words, smart integration of Evs into electricity system operation and design will not undermine their rollout, as the additional cost involved is estimated to be relatively modest.

It has to be noted that the cost savings quantified here represent the fundamental economic value of flexible EV management from a cost-optimal perspective. Our analysis does not discuss whether and to which extent this economic value would materialise in current or future market and regulatory environments or what the resulting cash flows for different players in the system would be. Unlike retail electricity prices, which include components such as taxes, incentives, profit margins etc., the incremental cost figures presented in this report refer to incurred additional cost due to increased expenditure associated with the investment into and operation of electricity system infrastructure driven by electromobility.

We show that the split benefits of flexible EV demand can span multiple sectors of the electricity system – balancing and energy arbitrage, ancillary service provision, generation capacity adequacy, and transmission and distribution networks. Given that these sectors are characterised by different market structures, competition levels and regulation, it will become necessary to develop an appropriate market and regulatory framework to support a cost-efficient integration of electromobility. One of the key challenges in that respect will be to devise commercial structures that deliver adequate revenues to flexible EV owners from diverse sources of value.

7.7 APPENDIX – POWER-TO-GAS. AN OVERVIEW OF POWER-TO-GAS IN PLANNING STUDIES.

Source	Region	Scenario	Power-to-X Implications	Observations
(ADEME, 2018)[117]	France	100% renewable gas supply by 2050	● between 85 and 135 TWh of synthetic gas (H_2 and CH_4), representing a 24 to 49% share of total supply	
(Belderbos, 2019)[119]	Belgium	requirement for synthetic gas storage in power systems with high shares of intermittent generation	● no major impact for vRES shares below 70% ● above 70%, potential reaches 8 and 4 GW (electrolysis and methanation, respectively) ● molecule storage also deployed at large scales (300GWh of H_2 and 13TWh of CH_4)	impact of vRES shares, CO2 reduction targets, technology costs on the optimal system configuration
(Berger, et al., 2019)[121]	Belgium	assessing the role of PtX in national, cross-sector decarbonisation strategies beyond 2030	● due to limited vRES potential, PtX competes directly with CCS technologies ● without CCS deployment, 3.2 GW of electrolysers and 1.2 GW of fuel cells are built, together with 300 GWh of H_2 storage	open-source, open-data model-based framework
(Breyer, et al., 2015)[126]	NE Asia	100% renewable energy supply in NE Asia	● up to 720 TWh synthetic methane potential region-wide by 2030	
(Bossavy, et al., 2018)[124]	EU	PtX providing flexibility to RES-dominated power systems	● for 63% EU-wide vRES supply in the electricity sector, 58 GW of electrolysis and additional 9 GW of methanation deployed (with the latter relevant solely in countries with low el prices and high vRES shares)	study commissioned by the EC
(Brown, et al., 2018)[128]	EU	95% reduction GHG levels compared to 1990 in the electricity, transport and heating sectors	● methanation as a cost-optimal solution to the decarbonisation of the heating sector ● PtX competes with cross-border interconn.; potential of at least 260 TWh of synthetic methane is identified	open-source, open-data model-based framework

(Brown, et al., 2019)[127]	EU	cross-sector synergies in reaching GHG reduction targets by 2050	● PtX, a relevant choice for GHG reduction targets above 80% compared to 1990 ● when co-optimized with cross-border interconn., PtX deployments are often limited to peripheral, vRES-rich regions	open-source, open-data model-based framework
(Colbertaldo, et al., 2018)[131]	Italy	role of H_2 in decarbonizing the transportation sector	● potential of 6.1 to 27.7 GW of electrolysis capacity to supply the entire H_2 demand for mobility (dep. on vRES penetration levels)	
(Gulagi, et al., 2017)[143]	Australia	100% renewable-based East Asia in 2030 supplied by rich-resource Australia	● PtX technologies used often as exporting pathways (as liquefied synthetic gas) from Australia to NE Asia consumption centres ● potential of over 2000 TWh of synthetic methane identified in a highly-RES scenario	
(Gasunie/Tennet, 2018)[139]	Germany / the Netherlands	PtX as chief flexibility provider for power system	● PtX appears mostly in scenarios centred around domestic supply of energy needs ● in the Netherlands, up to 75 GW of electrolysis capacity and 20 TWh of H_2 storage are required to cover close to 160 TWh H_2 year-round demand ● in Germany, 365 TWh of H_2 demand are supplied via 280 GW of electrolysis capacity and 75 TWh of storage, while additional 365 TWh of methane demand is covered by 40 GW of methanation and 50 TWh of storage	joint work of electricity and gas transmission system operators in the Netherlands (with assets also in neighbouring Germany)
(Gils, et al., 2017)[141]	Brazil	role of sector coupling in a 100% renewable-based Brazilian energy system	● exogenously considers an 85 PJ demand of hydrogen for transportation and industrial purposes; as well, up to 33 GW of hydrogen-powered gas turbines are required to contribute to overall system adequacy	

(Hansen, et al., 2019)[145]	Germany	H_2 role in supplying share of transportation demand	• adoption of PtX technologies leads to an improved economic system efficiency • 45 GW of electrolysis and 7.5 TWh of storage are required to serve 15% of the overall demand for transportation	
(Kanellopoulos & Blanco Reano, 2019)[146]	EU	electrolysis as main tech. for H_2 production EU-wide	• reaching strong decarbonisation targets leads to electrolysers (up to 1000 GW required to supply energy-intensive sectors) replacing conventional technologies in anc. services and cap. provision mechanisms	study commissioned by the EC
(Navigant, 2019)[151]	EU	carbon-neutral EU energy system by 2050	• potential of 160 TWh of H_2 supply from realistic vRES installed capacities in 2050 • deployment of dedicated vRES could lead to an yearly availability of over 2000 TWh of H_2 or 1160 TWh of CH_4	

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9 ABBREVIATIONS

AEL	Alkaline Electrolyser
BEV	Battery EVs
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CH_4	Methane
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CO_2eq	Carbon Dioxide Equivalent
COP	Coefficient of performance
COP21	21^{st} Conference of the Parties, referring to the countries that have signed up to the 1992 United Nations Framework Convention on Climate Change
CSP	Concentrated Solar Power
DC	Direct Current
DH	District Heat
DHN	District Heating Networks
DME	Dimethyl Ether
EB	Electric Boilers
EC	European Commission
EHPs	Electric heat pumps
ENTSO-E´s	European Network of Transmission System Operators for Electricity
ES	Energy Storage
ETIP SNET	European Technology and Innovation Platform Smart Networks for Energy Transition
EU	European Union
EV	Electric Vehicle
FC	Fast Charging
FinTech	Finance and Technology
FT	Fisher-Tropsch Synthesis
g	Gram
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt-hour
H_2	Hydrogen
HEVs	Hybrid Electric Vehicles

HFC-refrigerant	Hydrofluorocarbon refrigerant
HHPs	Hybrid heat pumps
HP	Heat pump
HT	High Temperature
HV	High Voltage
ICE	Internal Combustion Engine
ICT	Information and Communications Technology
IEA	International Energy Agency
IoT	Internet of Things
IR	Infrared
J	Moment of Inertia
K	Kelvin
kg	Kilogram
kW	Kilowatt
kWh	Kilowatt-hour
LAES	Liquid Air Energy Storage
LDVs	Light-Duty Vehicles
LHS	Latent Heat Storage
LT	Low Temperature
LV	Low Voltage
MeOH	Methanol or Methanol Synthesis
MT	Medium Temperature
MV	Medium Voltage
MVR	Mechanical Vapour Recompression
MW	Megawatt
MWh	Megawatt-hour
NH_3	Ammonia or Ammonia Synthesis
O_2	Oxygen
OPEX	Operational Expenditure
PbT	Payback Time
PEMEL	Proton Exchange Membrane Electrolyser
PHEVs	Plug-in Hybrid EVs
PtC	Power-to-Cooling
PTES	Pit Thermal Energy Storage

PtH	Power-to-Heat
PtX	Power-to-X
RD&I/RDI	Research, Development and Innovation
RES	Renewable Energy Sources
SAE	Society of Automotive Engineers
SC	Sector Coupling
SNG	Synthetic Natural Gas
SOC	Sate of Charge
SOEL	Solid Oxide Electrolyser
T	Torque
TES	Thermal Energy Storage
TRL	Technology Readiness Level
TTES	Tank Thermal Energy Storage
TW	Terawatt
TWh	Terawatt-hour
UK	United Kingdom
VHT	Very High Temperature
vRES	Variable Renewable Energy Sources

10 GLOSSARY

Energy density: Energy density is the amount of energy stored in a given system, substance, or region of space per unit volume.

EU28+3: The European Union’s 28 member states plus 3 (Iceland, Norway and Switzerland).

Hydrocarbons: Are organic compounds consisting entirely of hydrogen and carbon.

Interoperability: Interoperability is a characteristic of a product or system, whose interfaces are completely understood, to work with other products or systems, at present or in the future, in either implementation or access, without any restrictions.

Pit storage: Seasonal thermal storage, as lined, shallow dug pits filled with gravel and water as the storage medium.

Regulatory sandbox: Regulatory sandbox is a framework, set up by a regulator that allows FinTech startups and other innovators to conduct live experiments in a controlled environment under a regulator’s supervision.

Stack: The core electrolyser, excluding auxiliary system components such as rectifiers.

Stranded assets: Stranded assets are investments that are not able to meet a viable economic return and which are likely to see their economic life curtailed due to a combination of technology, regulatory and/or market changes.

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