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STORE&GO

Innovative large-scale energy storage technologies and Power-to-Gas concepts after optimisation

D8.8

The societal business case for power-to-gas: valuing positive and negative externalities

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Table of Contents

Executive Summary

This report shows that power-to-gas (PtG) is a technology that has various positive externalities (including environmental, health, grid cost and balancing and energy security benefits) that provide benefits to other stakeholder groups (like network operators and the broader society) in the market system, but not directly result in a commercially viable business case for PtG investments. We use a four quadrant framework (Chapter 1) to plot key PtG externalities (see Figure 1Figure 19), and discuss and analyse these externalities in more detail in chapters 3–6. We assess that to further the development of PtG in the EU, these positive externalities could serve as a rationale for policy change, and could be monetised and redistributed to cover the higher PtG investment costs and risks. We observe that within the current policy regime there is a risk of PtG underinvestment.

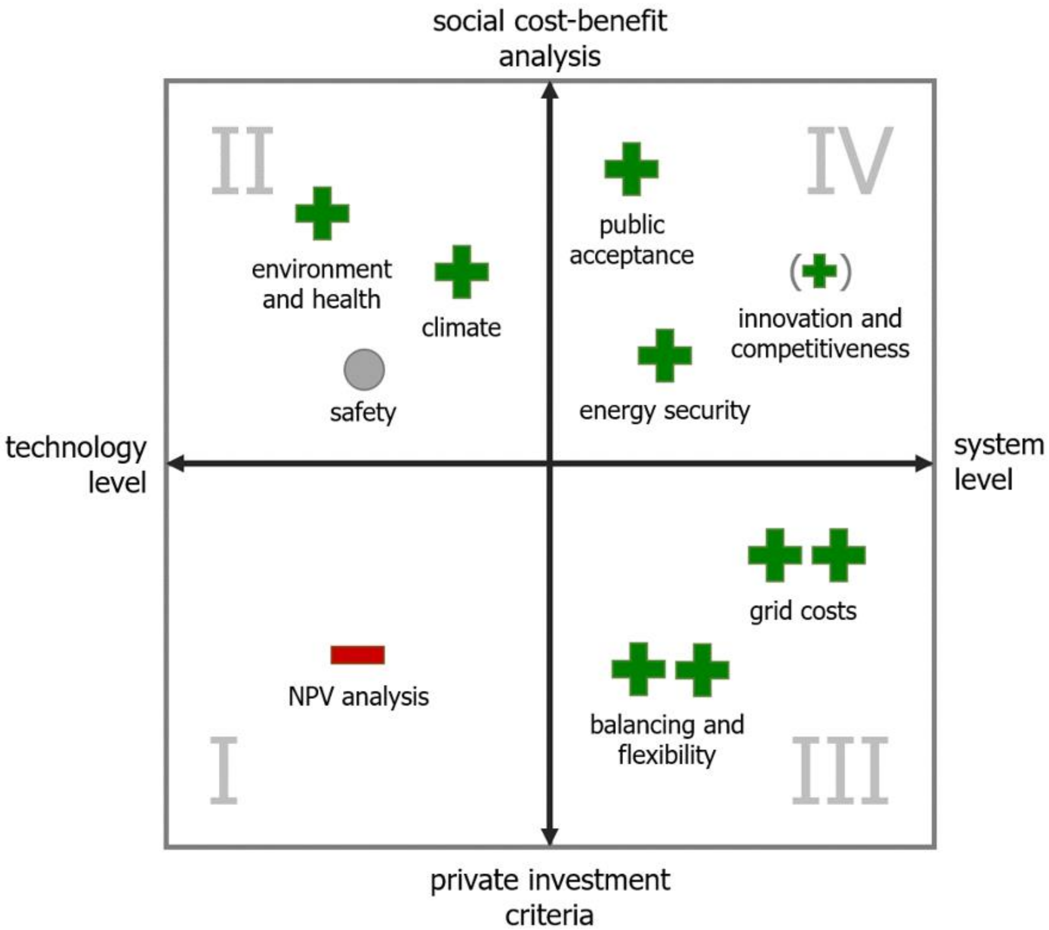

Figure 1. The four quadrants filled with key positive and negative effects of power-to-gas

In Chapter 7, we discuss in more detail different policy pathways to ensure that there is sufficient funding for PtG in the 2020–30 and post-2030 period. We recommend that the changes in policy regime should ideally follow a rationale where clear and quantifiable positive (and negative) PtG externalities can be internalised in the business case PtG. The three policy pathways discussed have the potential to ensure that sufficient funding for PtG is available.

We consider the EU's Innovation Fund (policy pathway 1) suitable primarily for the 2020–30 period, where it could fund a first batch of large-scale PtG projects on relatively short notice. However, we raise our concerns about whether or not this Fund will deliver sufficient PtG projects to push PtG out of the valley of death. For the post-2030 period we consider the two other policy pathways (i.e. 2.

Quota obligation and 3. PtG embedded in network tariffs) more suitable for generating sufficient funds that could match the EU wide PtG scaling needs (see Section 7.2). We briefly discuss some technical challenges, and requirements in terms of policy design for all three policy pathways in sections 7.3.1, 7.3.2 and 7.3.3).

We recommend that aside from initiating supply side measures to support the building and scaling of PtG demonstration plants, there is also a great need to tackle in parallel specific legal and regulatory issues (see (Kreeft, 2017)). In addition we put forward the idea that there could be a low-cost trajectory within the gas market transition phase (2020–50 period) when one would adopt measures to manage/control demand growth in the different end-use sectors (i.e. transport, industry and heating (see Figure 2), in line with infrastructure planning.

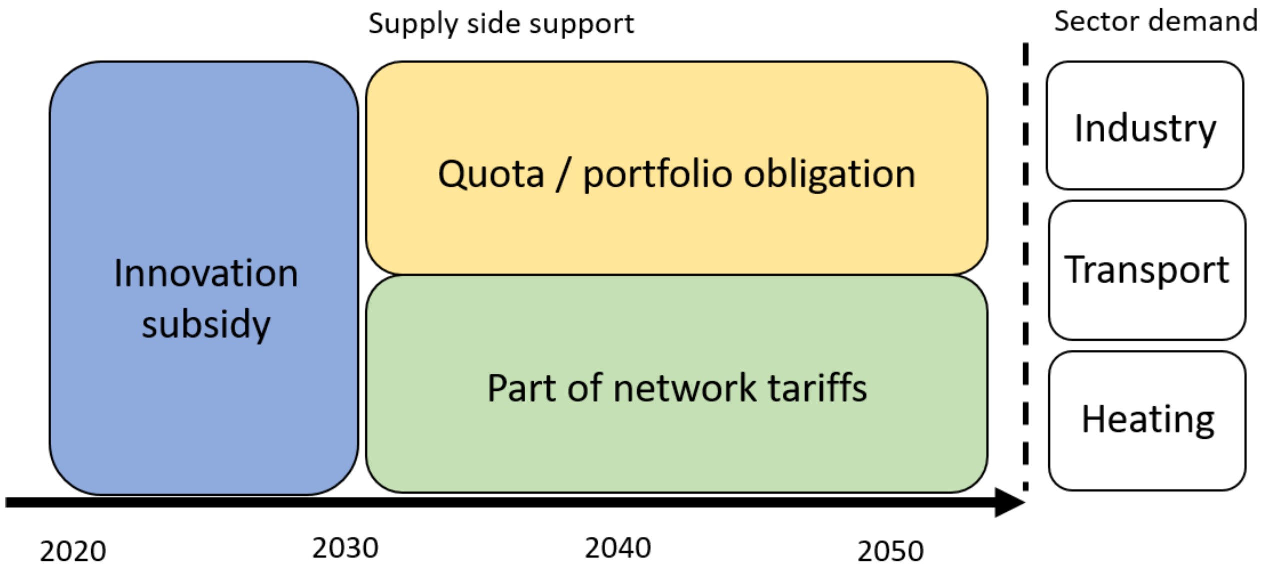

Figure 2. Potential supply side policy pathways and sector demand throughout the 2020–50 period

We emphasise that within the policy impact assessments, the distributional impacts are properly identified and (where possible) quantified, due to the notion that even with a perceived unfair or uneven distribution of the (financial) burden there could be an increasing public resistance to system change.

Disclaimer

With this report the authors have not attempted to assess and identify the 'best' or 'optimal' policy strategy for PtG developments throughout its technology life cycle. Instead, the authors aim to contribute to the discussion on internalizing positive externalities and using them as a rationale for policy reform within the energy transition in the EU.

1 Introduction: a basic framework for assessing power-to-gas externalities

Power-to-gas technologies are generally seen as the most likely future technologies to generate the required future volumes of green molecules to satisfy carbon-neutral energy demand and to serve as carbon-neutral feedstock in industry. Also, electricity storage via power-to-gas technologies is expected to be a promising solution to tackle future challenges in the e-grid caused by increasingly high shares of intermittent renewable power in the electricity mix: power-to-gas processes can convert (surplus) power into a more easily storable energy carrier. The first conversion step typically is the production of hydrogen via water electrolysis, but a next step can be to further convert the hydrogen into a synthetic fuel with an external CO or CO_2 source, via methanation, etc. So far, relatively little power-to-gas technology application, and in particular its methanation component, has come off the ground, both within and outside the European Union (EU). For scaling up power-to-gas in order to get to the required volumes of green molecules, development towards commercial-scale implementation and deployment is needed. In the process to get power-to-gas towards market maturity it is essential that the right, societal focus is chosen and the full spectrum of technological and non-technological challenges and issues adequately assessed. In other words, the assessment of power-to-gas feasibility needs to be comprehensive: the direct business aspects need to be considered, but also environmental, societal and acceptance impacts and implications for the costs and benefits of the related value chain.

Although ideally the societal costs and benefits of power-to-gas technologies would be assessed on the basis of such ‘integrated’ assessments, in reality assessment is mostly done from a more restrictive perspective (e.g. private cost-benefit analysis, techno-economic assessments, business case analysis, social-environmental impact assessment, or assessment disregarding impacts on the rest of the value chain). In other words, across the various assessments of (future) market suitability of power-to-gas technologies, perspectives differ widely depending on the analysts’ boundary conditions. This observation is important because, as we will argue in this paper, the perspective taken by the analyst can have a crucial impact on judging how urgently and rapidly policies and measures may be required to support power-to-gas technologies’ development as a major component of the energy transition, and how feasible at all power-to gas technologies can be.

In arguing about the assessment perspective, the fundamentally different perspectives that can be distinguished throughout the literature will be organised as illustrated in Figure 3 below.

On the vertical axis, the lower half indicates a private viewpoint, so that power-to-gas is assessed using private investment criteria (e.g. return on investment) of for example a company implementing a power-to-gas plant, or the private investment criteria of an energy system operator. The upper half indicates a societal viewpoint, which implies using a social cost-benefit analysis, or comparable societal assessment process, to assess the feasibility of a technology or energy system. The horizontal axis shows the dichotomy between an analysis at technology level on the left-hand side and at system level on the right-hand side. While assessing at technology level, the net effects of implementing a single technology or plant are considered, whereas at the system level also issues across the wider value chain, such as the impact on the energy transport system, and the wider economic and societal framework are incorporated into the analyses.

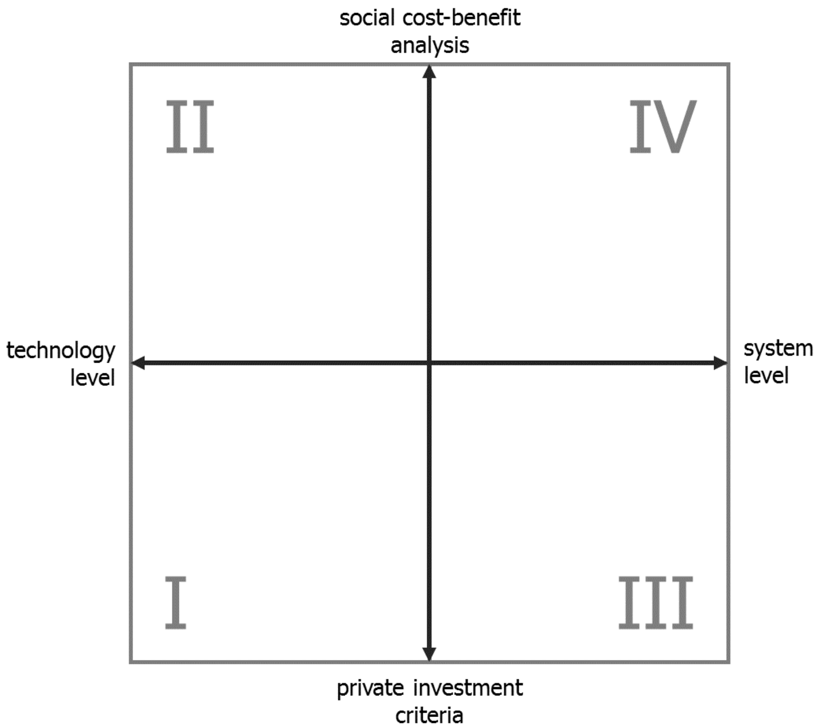

Figure 3. Four quadrants for analysis

The two axes provide a basic framework for determining the scope of the assessment of any technology, so including power-to-gas technologies. In short, quadrant I typically represents a basic assessment by a private investor that considers the company's costs and benefits (i.e. business case) when considering to develop a power-to-gas plant. Quadrant II encompasses a social cost-benefit analysis of such a technology, which may include, for example, environmental effects (e.g. reduced GHG emissions). Quadrant III covers the assessment of private costs and benefits at the system level, including issues related to energy transport networks, which would be costs or benefits for energy system operators. Finally, quadrant IV is on the assessment of all societal costs and benefits, so looking beyond the primary and private effects of introducing a specific technology (by also including e.g. secondary and tertiary effects within the relevant system). Assessment aspects in IV may relate to: energy security, overall economic competitiveness, the environmental impacts, and sustainability of the overall system. Some assessment aspects may be considered in more than one quadrant. For example, public acceptance of a specific energy technology relates to the societal costs of the individual technology (quadrant II), as well as to the related system infrastructure costs (quadrant IV). If public resistance threatens to hamper a projects' progress, it may also be included in a private investor's assessment (quadrant I).

In the following, we will focus on assessing the feasibility of power-to-gas with the help of the framework just presented. We will apply this framework in reviewing various outcomes of the STORE&GO project and other literature, in order to provide a robust and balanced structure and perspective to the debate on the role of power-to-gas in our future energy system.

1.1 Quadrant I: technology-level private investment criteria

Most projects are assessed by the potential investor on the basis of plant-level costs and benefits, i.e. the business case: the reasoning for initiating a project. That is to say, the various CAPEX and OPEX costs on the one hand and the expected returns on the other are weighed against each other in an NPV analysis, whereby only those costs and benefits are taken into account that accrue directly to the investor. Commonly, sensitivity analyses are carried out covering the various uncertainties and statistical margins in order to get a right perspective on both the NPV and its potential ranges.

A typical example is the investment in an electrolyser plant, with the purpose to turn green power into hydrogen. The investor will collect data on the CAPEX and OPEX of the electrolyser itself and the other related equipment needed, the costs of the input (power), and the returns on the output (hydrogen and possibly oxygen). Some additional costs related to the specific location and management and other operational costs will be included in the equation. Finally, this analysis underpins whether or not the expected financial return is acceptable given the expected level and uncertainty margins. Over the years, the topic of the techno-economic feasibility of power-to-gas has been studied quite extensively and in-depth. Recent examples of studies on technical-economic issues include Kopp, et al. (2017), Schiebahn, et al. (2015), Leonzio (2017), and Parra, et al. (2017).

Also the STORE&GO project has contributed to this field through among others three demonstration plants in Germany (Föcker, Ziehfreund, Schmidt, & Panofen, 2017), Switzerland (Lochbrunner, Gorre, Lydement, & Tonizzo, 2017), and Italy (Salvidia, et al., 2017). In the project also techno-economic issues have been assessed, such as the integration of power-to-gas in power systems (Bompard, et al., 2017), or the optimal time profiles for conversion technology (Gorre, Van Leeuwen, & Ortloff, 2018). STORE&GO has moreover added to the knowledge base on its economic feasibility through, for example, a stochastic net present value model assessing the feasibility of investment in power-to-gas conversion and storage technology (Van Leeuwen & Zauner, 2018; Van Leeuwen, 2018).

A key conclusion from this business case analysis of power-to-gas technologies (including the concept of methanation) by Van Leeuwen (2018, p. 17) is: “It is important to note that (…) both the methane and hydrogen production prices are still higher than the revenues of the gases. For a positive NPV these revenues should become higher.”

To put these key findings in its simplest way, it is hard to currently find a satisfactory business case for investing in an electrolyser to turn green power into green hydrogen, and a fortiori to take the additional step of hydrogen methanation. Various sensitivity analyses have meanwhile been carried out to see under what combination of factors an acceptable business case can be reached for power-to-gas by, for instance, assuming much lower CAPEX levels for the electrolysers and related equipment; by assuming lower electricity price levels; or assuming higher prices for green hydrogen. Some studies using this approach (Jepma, Smart sustainable combinations in the North Sea Area (NSA): Make the energy transition work efficiently and effectively, 2015; WEC, 2018; DNV GL, 2019) have concluded that if only the direct costs are concerned under a set of optimistic scenarios, production costs of green hydrogen can get smaller than those of fossil hydrogen by 2030 (blue hydrogen) or 2035 (grey hydrogen).[1] Although such conclusions may give rise to optimism, it still is quite uncertain if and when such conditions may be part of reality.

[1] In other words: production costs of green hydrogen may be lower than those of fossil hydrogen with carbon capture and storage (CCS) by 2030, and also cheaper than fossil hydrogen without CCS by 2035. This conclusion was reached based on the combination of the following assumptions: cost of natural gas raises from about €7/GJ in 2020 to about €9/GJ in 2050; CAPEX electrolyser declines from €800–1100/kWe in 2020 to about €500–700/kWe in 2050 [note that much lower – €200-300/kWe – figures are mentioned in industry]; renewable electricity prices decline from about €29/MWh average to almost €0/MWh during some 3000 hours per year (assumed running time electrolyser); and carbon costs per kg of grey hydrogen raise from about €0.06/kg in 2020 to >€0.50/kg in 2050 (DNV GL, 2019; chapter 3).

In short, a plant-level assessment using private investment criteria will have a negative outcome for years or even decade(s) to come. This makes that investors will be reluctant to invest in power-to-gas technology based on the business case in quadrant I. In order to enable power-to-gas investments, the business case (in quadrant I) will need to be positive. Options for shifting positive externalities from quadrants II, III, and IV to the business case will be discussed in chapter 8.

Effects of externalities or system costs and benefits are not included in a quadrant I assessment. In this report, we will therefore also focus on, instead, including the broader socio-economic and environmental impacts (or externalities) of power-to-gas in the assessment framework, in accordance with quadrants II, III, and IV. Some aspects of the II,III and IV framework perspective have already been included in the STORE&GO project analyses, including the environmental impacts (Codina, et al., 2017; Blanco, et al., 2018), public acceptance issues (Azarova, Cohen, Friedl, & Reichl, 2019); and the relevant legislative frameworks (Kreeft, European Legislative and Regulatory Framework on Power-to-Gas (D7.2), 2017; 2018), but there have been no analyses from a comprehensive social cost benefit framework.

1.2 Quadrants II, III, and IV: a broader assessment

Analyses in quadrants II, III, and IV are broader than those in quadrant I, either in terms of the criteria (social cost-benefit analysis rather than private investment assessment), or in terms of the boundaries of the analysis (a systems perspective rather than an assessment at plant level), or both.

An assessment in quadrant II focuses on externalities and overall societal costs and benefits that can be related to the investment itself. Such costs and benefits can, for instance, relate to the environmental effects of energy investments, such as impact on air quality or greenhouse gas emissions. In quadrant III it is recognised that a specific technology cannot be assessed without recognising that it is part of an overall energy system: one should not look at the generation of renewable energy only, but also at its transport, storage, and application potential. In quadrant III, therefore, an attractive technology investment if considered in isolation may yet fail in the absence of feasible transport and storage modes or, worse, in the absence of sufficiently good application options. In quadrant IV, finally, power-to-gas is assessed from the complete social costs and benefits perspective of the overall system it is part of: is power-to-gas a pathway for the energy system that in the end offers a higher societal return? The latter approach includes aspects such as the overall strength and competitiveness of the economy, or energy security.

Only a few studies assessing the feasibility of power-to-gas technologies have so far tried to take a broader perspective by also including a range of elements of the system costs and benefits or externalities in the assessment. A common feature of all power-to-gas assessments seems to be that none of them covered all system costs and externalities, but rather zoomed in on a few of these cost/benefit elements. Examples in the STORE&GO project include Liao and Codina (2018), who focused on environmental life-cycle aspects; Van der Welle, et al. (2018) focussing on energy mix diversification and energy security; and Blanco (2018) focussing on the energy system flexibility costs and benefits. Examples related to offshore power-to-gas are Jepma and Van Schot (2017) and Jepma, et al. (2018), where the broader implications for the transport of energy produced offshore are included in the feasibility assessment of using offshore platforms as locations for converting offshore wind power into hydrogen. In the latter study it was concluded that if all wind power would be converted, this “technology turned out to be highly beneficial under the assumption that the savings on e-grid investment that otherwise would need to have been made are taken into account in the NPV calculus (impact on the ‘green’ hydrogen production costs about € 1.50 per kg)” (p. 5).

On the whole, based on this type of studies, it turned out that an analysis of power-to-gas is more positive if the externalities and system costs of quadrants II, III, and IV are included, rather than using a private plant-level focus of quadrant I alone. In other words, disregarding system components and externalities creates a negative bias towards the societal benefits of enhancing power-to-gas technology. Obviously, ideally an integrated assessment would be carried out involving all (social) cost components. As was argued already, such an analysis does not exist, however. Even modelling efforts that try to cast power-to-gas technologies in a wider modelling structure covering the overall energy system, such as ExternE[2] and TIMES[3], suffer from the fact that only some of the cost and benefit aspects, notably environmental impacts or energy security issues, are included in the analysis.

In the following , we will focus on both positive and negative externalities and system costs of power-to-gas, thereby clearly going beyond the level of micro-economic and sector-specific impacts of power-to-gas only. In doing so, we will typically explore impacts of power-to-gas on the broader socio-economic systems and the environment. We will also explore if there are biases in the type and scope of externalities assessed in energy-related studies. In the following, first a literature review will be presented on energy-related externalities most frequently included in relevant publications. This way also insight can be gained on ‘white or blind spots’ in externality research for power-to-gas. Methods, models and approaches will be explored to assess and, if possible, quantify power-to-gas externalities, and to determine if power-to-gas analysis can benefit from using aspects and methods from all four quadrants. The report’s final chapter 8 will focus on possibilities for ‘shifting’ positive externalities from quadrants II, III, and IV to quadrant I, in order to improve the business case and enable power-to-gas investments.

[2] http://www.externe.info
[3] https://iea-etsap.org/index.php/etsap-tools/model-generators/times

2 The externality concepts

STORE&GO's Deliverables D8.3 (Van Leeuwen & Zauner, 2018) and D8.4 (Van Leeuwen, 2018) analysed the business case of power-to-gas, using a net present value (NPV) modelling exercise. In order to provide a more comprehensive societal picture of the future perspectives of power-to-gas, as was argued before, we have to look at the technology from a wider societal perspective, taking into account not only the business case of electrolysis, methanation, storage, and/or injection into the natural gas grid on a plant or company level (quadrant I), but also issues such as environmental impacts (quadrant II), the costs and stability of the grid (quadrant III), and wider economic and system effects (quadrant IV). In other words, we will have to analyse the various externalities of the introduction of power-to-gas in the energy system.

In the economics literature, the concept of externalities has been discussed in a wide range of studies. Berta (2017, p. 288) describes them as "a type of missing market", which encompasses "the unpriced effects of one agent's activity on the welfare of another agent." Mundt (1993, p. 46) defines 'externalities' as "uncalculated and/or uncompensated exchange outcomes" of all types that may accrue to transacting parties. In this study, we use a similar definition for externalities, focusing on all outcomes or effects that are unpriced, uncalculated or uncompensated in the business case itself, or, as Aunedi, et al. (2016, p. 1) define externalities: "various types of costs that are imposed on the system (…) but which are not included in the capital or operating cost estimates of these technologies."

It is important that in this definition it does not necessarily mean that these effects are unintended or unknown. Several authors claim that only unintended effects can be externalities, and that deliberate effects are by definition no externality (Baumol & Oates, 1975; Browning & Browning, 1987). Others assume that externalities are by definition not anticipated and therefore unknown (Nason, 1986). In this study, however, the definition of externalities is not narrowed in such a way. Externalities are considered to be all costs and benefits, or otherwise all side-effects, that are additional to the private costs or benefits of the business case. Synonyms for externalities would therefore be 'spillovers', 'external costs/benefits', 'trade-offs'/'co-benefits', and 'hidden costs/benefits'. So, in our definition, a social cost benefit analysis includes "all of the costs and benefits to society as a whole" (Boardman, Greenberg, Vinning, & Weimer, 2017), and therefore includes both private costs and benefits, and all externalities.

Figure 4 shows a categorisation of cost (and benefit) types, that together form the overall social costs of for example a certain energy technology or project, adapted from the categorisation by Samadi (2017, p. 3). Considering that in the STORE&GO programme Van Leeuwen (2018) has already focused on the private costs and benefits of a power-to-gas project (quadrant I), this report focuses mainly on quadrants II, III, and IV, or the cost implications of introducing power-to-gas technologies on a larger scale in the European economy and society. This report therefore tries to cover all cost components that are external to the plant level costs, so: system costs, specific, and generic external costs, including macro-economic and geo-political costs.

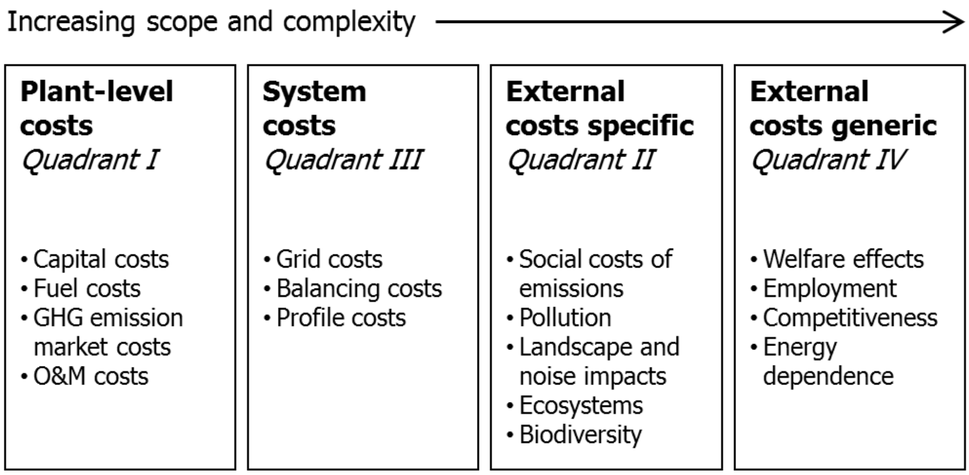

Figure 4. Main cost categories differentiated when determining the total social costs of energy technologies or projects

When considering a technology, ‘system costs’ (quadrant III) may or may not be considered. An electrolyser, for instance, is a single technology capable of converting power into hydrogen, the investment costs of which will typically be covered by the investor in electrolyser capacity. Commonly other players in the value chain will cover the related costs for transport capacity, and storage infrastructure capacity, as well as capacity costs for the final use (of hydrogen). Introducing the same technology will even have cost implications for the wider energy system e.g. insofar as the risk of curtailing renewable power from wind or solar is affected, or the ease of e-grid balancing. (Most of) these ‘system costs’ are typically external to the investor in the electrolyser capacity, and will commonly accrue (at least partly) to other stakeholders such as the government, energy DSOs and TSOs, or energy end users and taxpayers. Some authors consider such system costs not to be externalities. Doukas, et al. (2011, p. 979), for example, state that “costs born[e] by governments, including direct subsidies, tax concessions, indirect energy industry subsidies (e.g. the cost of fuel supply security), and support of research and development costs, are not considered externalities.” However, since these costs are external to the ‘plant-level costs’ directly borne by the investor, in this report quadrant II-IV costs will be considered external.

Next to system costs, still other typical external costs (quadrant II) can be distinguished, i.e. costs that are not or cannot (easily) be assigned to specific stakeholders or economic agents, but are often borne by society as a whole. Typical examples are costs related to: greenhouse gas emissions, air or water pollutants (including their health related impacts), impacts on safety levels, landscape and noise impacts, or impacts on ecosystems and biodiversity. Just like public goods, so can externalities be characterised by being non-excludable and non-rivalrous. In other words, individuals cannot be excluded from its impact, and impact to one individual does not reduce impact to others. Obviously, insofar and to the extent that emissions will be charged to those who have caused them, e.g. in the case of greenhouse gases by the EU Emissions Trading System (EU ETS), such emissions will no longer be external to their source because they are then internalised in the plant-level costs.

Next to the above external effects, a last category of externalities can be distinguished, having a more generic adverse societal impact in common, and therefore typically are harder to quantify, namely the macro-economic and geo-political costs (quadrant IV). These effects, while highly important from an overall national welfare perspective, typically relate to the technologies’ impact on: overall employment, competitiveness, the innovation level, the geo-political conditions including energy import dependencies, etc.

In order to identify, prioritise and select the relevant externalities – including system costs, external costs, and macro-economic and geo-political costs – for consideration, in the following a literature review has been carried out on the various externalities of power-to-gas technologies as well as of the energy system in general.

3 Literature review of externalities concepts

3.1 Literature searching method

In order to follow a systematic and transparent approach for reviewing the literature on externalities, the method introduced by Hanger, et al. (2016) in the EU-funded TRANSrisk project was used. This method uses: a reproducible search algorithm, clear criteria for inclusion and exclusion of articles, and a protocol for data extraction.

In order to search for relevant articles, the online database of Scopus was used. It provides a huge selection of academic articles, in both physical and social sciences.

The search for relevant externalities has subsequently been based on search runs combining the search term: “externalities” (or one of its synonyms), with a search term related to ‘energy system’ or ‘power-to-gas’ (see below).

Table 1. Search terms for literature searching

Search term 1	Search term 2
Externalities	“Energy system”
Trade-offs	Electrolysis
Co-benefits	“Power-to-gas”
“External costs”	“Power-to-methane”
“External benefits”	“Hydrogen economy”
“Spill overs”	Methanation
	“Energy storage”
	“Energy conversion”

In order to limit the number of results and to ensure them to be sufficiently up-to-date, search runs were limited to articles and book chapters published since 2009 only. The search fields TITLE (i.e. the publication title), ABS (the abstract) and KEY (keywords given by the authors and generated by Scopus) were included. This led to the following search query in Scopus.

TITLE-ABS-KEY({search term 1} AND {search term 2}) AND PUBYEAR > 2008

Search runs using this query in combination with the 48 search term combinations resulted in 630 search results. From this sample double-counted articles were removed, and the sample was further restricted to online available versions of the publications, accessible either through open access or by using access provided by the University of Groningen. Subsequently a manual selection was carried out in order to remove irrelevant articles. Most irrelevant articles focused mainly on technical issues within a plant or system, such as on the co-benefits or trade-offs of certain choices. For the search term ‘spill over’, many articles specifically on knowledge spill overs. After the manual selection, a remaining set of 135 publications was selected for further analysis.

3.2 Externalities in literature

The focus of the externalities literature reviewed is visualised in Figure 5. Of the 135 selected publications, a majority of 101 (75%) focuses on or at least extensively considers climate change. Because climate change is the main driver of the energy transition decisions, including about power-to-gas technologies, this finding is not surprising. Most (79) of the publications discussing climate change focus on the impacts of a project, policy or technology on emissions of CO_2 and/or other greenhouse gases. Some other publications primarily focus on climate change costs or benefits.

Also other, non-climate, environmental effects are an important issue discussed in many of the articles. In total 74 articles (55%) focus on environmental effects including air, water or soil pollution, ecosystems, materials conservation, and noise. 37 articles specifically discuss the human health impacts of environmental effects, mainly of local air pollution. Specific environmental effects discussed further include radiation risks, oil spills, deforestation, light pollution, platinum depletion, landscape impacts, crop damage, marine acidity, odours, pests, and soil erosion.

The focus on climate change and environmental effects shows that the emphasis in literature is mostly on specific externalities in quadrant II. Only a few articles (4%) also focus on safety aspects.

The articles selected discussed and analysed a range of other externalities and system costs in quadrants III and IV. These include 'system costs' such as effects on the grid, balancing, and flexibility (26%), or overall energy system costs (10%); while in quadrant IV the focus has been on a range of macro-economic and geo-political issues including energy security (21%); effects on the overall economy (12%) including on employment, GDP and poverty; public acceptance and human behaviour (10%); and issues related to competitiveness and innovation (5%). It must be noted that some externalities can be placed in multiple quadrants. For example, public acceptance can be related to the acceptance of an individual energy plant (quadrant II), or to the acceptance of the overall energy system including transport networks (quadrant IV).

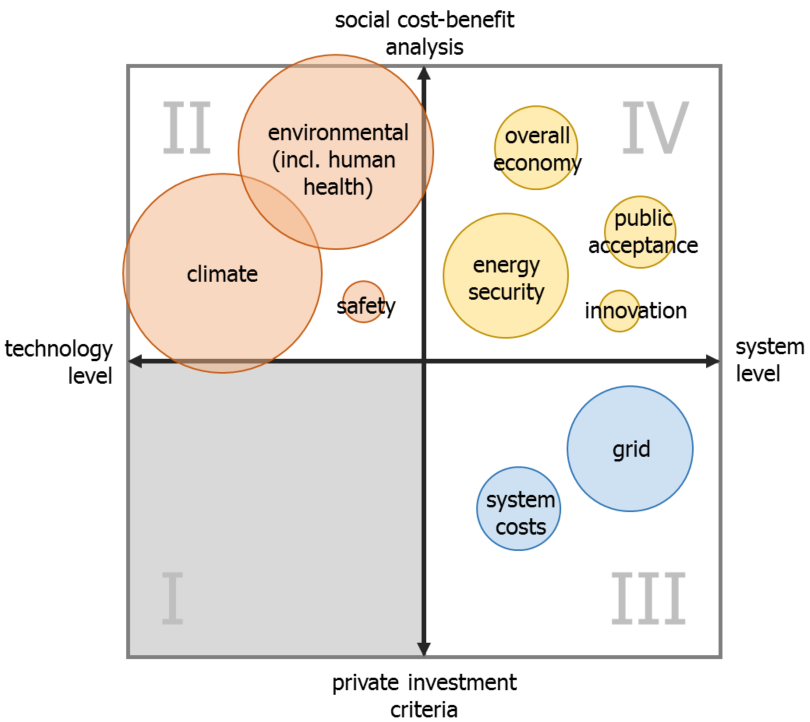

Figure 5. Outcomes of the literature review: focus of relevant literature on externalities in quadrants II, III, and IV

The above analysis clearly shows that there is a vast set of literature on externalities in the energy system, also including externalities of power-to-gas technology and other aspects of the hydrogen economy. So, there is ample information that may guide decision-making in energy technology policy and investments. However, analyses usually focus on only a subset of the relevant aspects. For example, many of the academic articles mentioned above analyse the business case of an energy technology in combination with its climate change externalities, possibly also scrutinising its effects on, for example, air pollution and human health. Other articles may focus on competitiveness issues, grid flexibility and balancing, overall energy costs, and/or public acceptance. None of the articles, however, examines all issues coherently, i.e. including plant-level costs, system costs, external costs, and macro-economic and geo-political costs. An example of an article that aimed to combine the analysis of many aspects of the energy transition is Jantzen, et al. (2018), including the planning elements of the political energy targets, sociotechnical priorities, civic engagement, the energy vision, energy balance, policy implications, and demand-side management. Notwithstanding the complexity of this analysis, important elements such as local pollution had to be disregarded to keep this analysis manageable, and also the total costs of the energy system were only touched upon briefly.

Jantzen, et al. (2018), focusing on the small island community of Samsø in Denmark, used a simple 'urban dynamics model' to analyse the local energy transition and its many elements and objectives. As recognised by Jantzen, et al. (2018, p. 33), "the advantage of the model is its ability to combine engineering with social studies." This, however, also means that the "approach may seem unscientific and lacking of background scientific and technical knowledge" on the one hand, but "may seem too stringent to a scientist within the social studies."

In practice, in order to analyse an energy technology or energy transition approach, complementarity between quantitative and qualitative tools is needed. As argued by Van der Gaast, et al. (2016, p. 10), quantitative models can be used to assist in making choices about technology options "by balancing their benefits and costs, and considering these at a required scale to enable a transformation." However, such models cannot provide information on how these benefits and costs are perceived by people, and what this means for the social acceptability of a technology option. Therefore, participatory, qualitative analysis "can facilitate a much more detailed discussion on benefits and costs as perceived by stakeholders and to what extent people are willing to accept energy installations near their home environment." For stakeholders, however, it may be more difficult to assess the options at a larger scale, and often the issues at hand are too complex to be considered by stakeholders in an all-encompassing manner. It is for this reason that the TRANSrisk project (Van der Gaast, et al., 2016) has demonstrated how quantitative models and qualitative participatory processes can complement each other.

Specifically for the energy sector, and new energy technologies, a range of models and analytical approaches have been developed to analyse their costs and benefits, including some of the externalities. One frequently used approach has been the Impact Pathway Approach as developed in the ExternE project series, used to quantify environmental impacts and give them a monetary valuation. As indicated, the "ExternE methodology aims to cover all relevant (i.e. not negligible) external effects. However, in the current state of knowledge, there are still gaps and uncertainties" (Bickel & Friedrich, 2005, p. 13). ExternE covers environmental impacts (air, water, and soil pollution), global warming impacts, and accidents, and a first attempt at including energy security. The approach and its related models however do not cover system costs related to grid investments and macro-economic and geo-political aspects such as employment, innovation, and competitiveness. Public acceptance issues are also not considered. In other words, although ExternE is a wide-ranging approach and model that has been continuously developed over several decades and applied in numerous studies, it does not cover plant-level costs, system costs, external costs, and macro-economic and geo-political costs comprehensively. It illustrates that a comprehensive modelling approach of energy transition issues and energy technology investment decisions is very hard to achieve.

An example of how to integrate the ExternE model with existing energy system optimisation, based on net present costs, as well stakeholder engagement, has been given by Apichonnabutr and Tiwary (2018). This combined approach is shown in Figure 6.

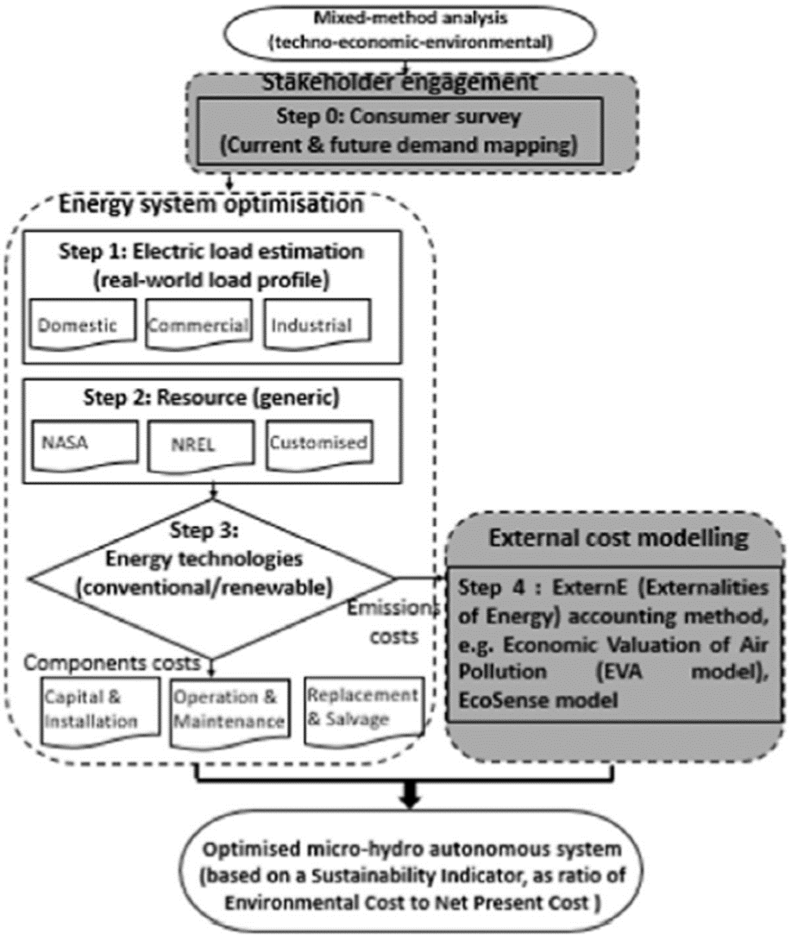

Figure 6. Framework for assessing trade-off between economic and environmental performance of an autonomous energy system: proposed advancement to the current practice (Apichonnabutr & Tiwary, 2018, p. 892)

Optimising the future energy system, and the role of power-to-gas in this, must be based on a very wide range of multiple objectives and their relative trade-offs. This includes, as discussed above, the plants-level costs as well as a multitude of 'externalities', including system costs, external costs, and macro-economic and geopolitical costs. As discussed by Parkinson, et al. (2018, p. 478), "planners tasked with designing (…) energy (…) infrastructures are faced with a plethora of technologies and a wide variety of economic, social and environmental conditions, which make it difficult to decide which technologies to invest in and promote, and in what order." Considering that models and other approaches are not able to provide comprehensive insights, it will be important for policy-makers, in collaboration with other stakeholders, to consider all aspects and externalities both in isolation and in conjunction. Models are often useful to streamline this process, but, as the discussion above clarifies, decisions should not be taken based on a single model or approach, as none is able to provide a complete and comprehensive overview of an energy option including all its relevant externalities.

Keeping in mind that no integrated assessment models exist that cover quadrants I to IV, this report continues to consider the various relevant externalities and system costs in quadrants II, III, and IV in order to identify their relevance for assessing power-to-gas technologies. Specific externalities (quadrant II) are discussed in chapter 4; system costs (quadrant III) in chapter 5, and generic externalities including macro-economic and geo-political costs (quadrant IV) in chapter 6.

4 Studies on quantifying specific externalities (quadrant II)

4.1 Externalities: quantifying climate change impacts

The energy sector is the largest contributor to global greenhouse gas emissions, with worldwide about 35% of emissions coming directly from energy production (Bruckner, et al., 2014). In the EU, some 54% of emissions are attributed to fuel combustion, excluding transport (Eurostat, 2018). When deciding on interventions in the energy sector, its effects on emissions – and indirectly on climate change – are therefore a key consideration.

The overall energy use has remained relatively stable in recent decades. Primary energy consumption in the EU-28 has fluctuated between about 1,500 and 1,800 Mtoe between 1990 and 2016, with no downward trend visible (European Commission, 2018, p. 79). It is therefore urgent to find novel routes for the traditional energy industry to switch away from fossil fuel use, and generate the required energy in a sustainable manner (Chen, Tang, Lei, Sun, & Jiang, 2015). It is important to note that the impacts of energy generation on climate change still mostly are an externality, i.e. not (automatically) considered in investment decisions.

The actual socio-economic cost of CO_2 emissions from energy production is difficult to estimate (Jensen & Skovsgaard, 2017). However, more and more economies introduce a form of carbon pricing: by 2019, about 15% of all global emissions are now covered by regional, national and sub-national carbon pricing initiatives (World Bank and Ecofys, 2018). In the EU, this includes primarily the EU Emissions Trading System (EU ETS), but also the UK carbon floor price and the carbon taxes in Denmark, Sweden, Finland, Ireland, France, Spain, and Portugal. The cost of climate change has accordingly been internalised in the business case of energy generation, although it remains unclear to what extent the actual carbon price represents the costs of climate change impacts. Nevertheless, several studies use either the current or expected future carbon price to estimate the climate change abatement costs (Jensen & Skovsgaard, 2017; Cantuarias-Villessuzanne, Weinberger, Roses, Vignes, & Brignon, 2016; Massarutto, De Carli, & Graffi, 2011).

From a social welfare perspective, climate change and other environmental costs should be fully taken into account in order to comprehensively assess the societal costs and benefits of energy technologies. One can question if that is currently the case. For instance Kuckshinrichs and Koj (2018) argue that the existing carbon pricing instruments internalise climate change impacts only partly (i.e. these costs are only partly considered in quadrant I).

Alberici, et al. (2014, p. 15) have attempted to value climate change “based on estimates of the damage done in the future by emissions now.” Based on various estimates, they arrive at a value of 50 $€_{2012}/tCO_2e$, assuming the currency value of 2012 and being consistent with a mid-high global warming pathway. For sectors covered by the EU ETS or other carbon pricing instruments, the actual price of a tonne of CO_2 should be subtracted from this value in order to get to the missing penalty. This way, for example Kuckshinrichs and Koj (2018, p. 625) arrive at a monetary value of the climate change externality of 0.0441 $€_{2015}/kgCO_2e$, or 44.1 $€_{2015}/tCO_2e$. In other words, even if energy generation is already subject to carbon pricing (incorporated in quadrant I analysis), it is well possible that an additional external cost has to be considered in quadrant II.

While climate change impact or ‘global warming potential’ could be added as a negative externality to energy technology investments, for power-to-gas it may, surprisingly enough, under some conditions be included as a positive externality or ‘hidden benefit’. That can be the case if the expected emissions will be lower than in the considered applicable baseline case, such as natural gas production or electricity generation from coal. Obviously in such cases the chosen baseline will need to be substantiated carefully. For an illustration of the dilemmas that may arise, see Li, et al. (2018).

In the STORE&GO project, the environmental impacts of power-to-methane have been analysed, including its climate change impact (Codina, et al., 2017; Blanco, et al., 2018; Blanco, 2019). Figure 7 shows a typical breakdown of the CO_2 footprint of power-to-methane in a future decarbonised economy. The minimum impact consists of the equipment impact on the CO_2 footprint, with expected 0.74 gCO_2eq/MJ from the construction of the methanation equipment and 0.46 gCO_2eq/MJ from the construction of the electrolyser. The power-to-methane's carbon footprint depends mainly on the power generation, and the construction of the power generation devices. In Figure 7, the footprint has been calculated based on a forecasted future electricity mix in Germany, with a combination of wind and solar power.

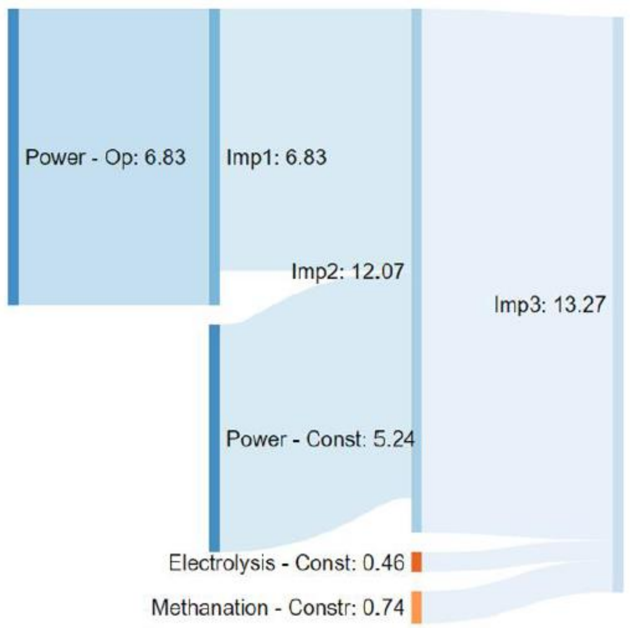

Figure 7. Breakdown of CO_2eq footprint for synthetic methane from power-to-methane, in gCO_2eq/MJ. Applicable for Germany in a 95% emissions reduction scenario without CCS (Blanco, 2019, p. 28)

Considering the relatively low CO_2 impact of the electrolysis and methanation equipment, the electricity mix used (and the carbon footprint of the subsequent transport and storage activities relative to the alternative) determine the bulk of the carbon footprint. Blanco (2019) assumes a carbon footprint for natural gas production of between 58 and 85 gCO_2eq/MJ. If one disregards potential CO_2 impacts from transport and storages, power-to-methane will have a lower footprint if the related power production has a footprint of less than 56.8-83.8 gCO_2eq/MJ, corresponding to 122.6-180.9 gCO_2eq/kWh of electricity produced. Because forecasted future electricity mixes in the main scenarios for European countries are well below these values, it is likely that under future conditions the climate impacts of power-to-methane will be lower than those of the current natural gas production.

4.2 Externalities: quantifying other environmental and human health impacts

As clarified by Cassetti and Colombo (2013, p. 874), in addition to environmental impacts of the energy system with a global impact – including chiefly the emission of greenhouse gases – there are those with a local impact. These are typically “due to emission of dangerous substances capable of altering the local ecosystem.” In this case, ‘local’ does not necessarily mean in the immediate vicinity, as also distant areas can be impacted “that are in the trajectory of pollutants dispersion” (Czarnowska & Frangopoulos, 2012, p. 212), with air pollution spreading through wind and water pollution through rivers, for example. Local environmental externalities, however, not only include ‘emissions’ leading to air, soil, or water pollution, but can also include noise, odour, natural resources depletion, and impacts on the landscape.

Local environmental impacts can be assessed quantitatively by analysing the contamination of the atmosphere (air), hydrosphere (water), and lithosphere (soil), as well as the ecosystem quality and biodiversity loss. Especially air pollution, but to a lesser extent also noise and odour, can have an adverse impact on human health. According to Shukla and Mahapatra (2011, p. 3), “the cost of health impacts far outweighs damage from all other categories.” Next to such quantifiable aspects there are also qualitative issues, such as a decreasing comfort of life or happiness as a result of noise disturbance or visual pollution.

As discussed by Karlsson, et al. (2016), the impacts of air pollution can be translated into socio-economic costs by measuring or calculating the health impacts. A wide range of studies has confirmed the links between air pollution and health. Pope, et al. (2009) “provide evidence that improvements in air quality have contributed to measurable improvements in human health and life expectancy.” Air pollution has been associated with, among others, cardiovascular and respiratory diseases, diabetes, premature births, infant mortality, and asthma (Brandt, et al., 2011). Based on the notion that air pollution health impacts can be valuated, in Denmark the EVA model (Economic Valuation of Air pollution) was developed, following an impact-pathway methodology as illustrated in Figure 8.

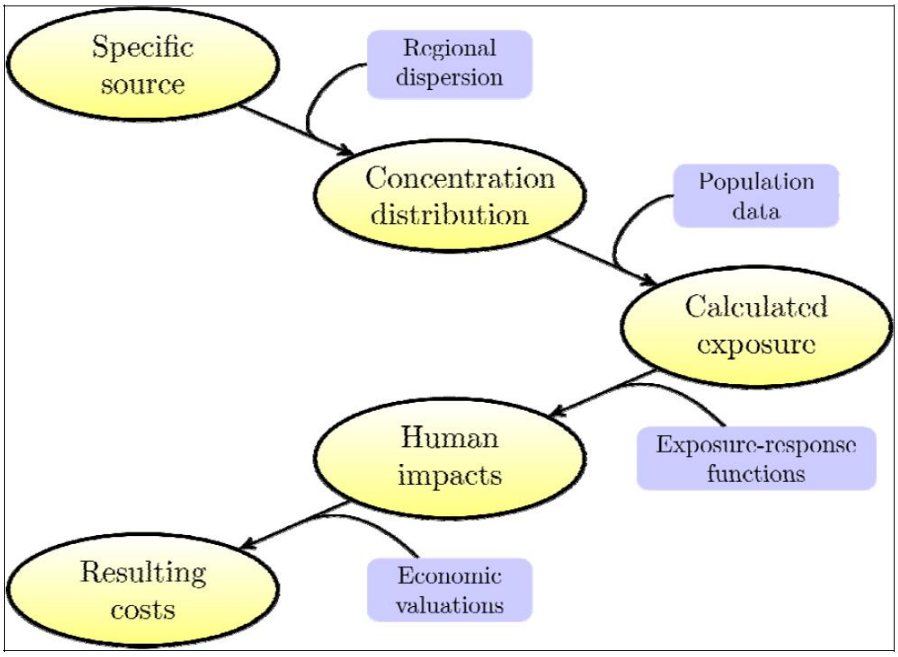

Figure 8. Schematic diagram of the impact-pathway methodology of the EVA model (Brandt, et al., 2011, p. 12)

For determining the ‘resulting costs’, an economic valuation of health impacts is needed. In environmental economics, for this the metric of ‘Value Of Life Year’ (VOLY) can be used: “the willingness to pay for increasing life expectancy by one additional year” (Chiabai, Spadaro, & Neumann, 2018, p. 1165). An alternative is the ‘Value of Statistical Life’ (VSL), which is based on “the individual willingness to pay for small reductions in the risk of dying.” Such health effect valuations have been calculated in detail for a wide range of health effects, with for example Brandt, et al. (2011) estimating the costs of a death because of chronic bronchitis as a result of air pollution at € 52,962 per case, and the cost of lower respiratory symptoms in children at € 16 per day. Such costs are linked to actual measured air quality by using an ‘exposure-response coefficient’, setting the estimated health effect as a result of a certain change in air quality, i.e. a change in the level of particulate matter, ozone, carbon monoxide, sulfur dioxide, etc. To provide an indication of the level of external costs in Europe as a result of air pollution, Brandt, et al. (2011, p. 8) set the total health-related external cost for Europe at € 803 billion per year for 2000, decreasing to € 537 billion per year for 2020. The decrease is the result of actual and predicted decreasing air pollution levels. “The results in this study show that air pollution constitutes a serious problem to human health and that the related external costs are considerable” (Brandt, et al., 2011, p. 49).

Obviously, the health effects of air pollution, and therefore also its economic valuation, depend not only on the kind of air pollution, but also on its spatial dispersion affecting the calculated exposure. Also Zvingilaite (2013, p. 60) clarifies how health damage costs of different air pollutants depend not only on weather conditions (such as wind) and population density in the affected areas, but also on “other pollution sources and pollutants in the atmosphere”, as different pollutants can be subject to chemical transformation leading to increased effects.

Pollution does not only have human health impacts. Air pollution can also lead to impacts such as: reduced visibility, decreasing agricultural productivity, material damage, and effects on biodiversity. Similarly, water pollution could lead to reduced water quality, fish poisonings, impacts on fisheries, or reduced opportunities for recreation (Kusiima & Powers, 2010). The EU-funded NEEDS project (2009) therefore took the analysis a step further by monetising the impact of air pollution based on not only health impacts but also on loss of biodiversity, crop yield losses, and material damage. For all analysed energy technologies and sources, health impacts turned out to be by far the most impactful external cost. ‘Local’ environmental externalities of energy production and use encompass, as mentioned, not only pollution but also for example landscape impacts, noise, odour, land use, natural resources depletion including water use, and ecosystem alterations. Many of these impacts are interrelated.

Impacts on the landscape as well as noise and odour are difficult to quantitatively assess, because their perception is subjective. For noise, for example, “the perception of sound as ‘disturbing’ depends on the level of other sound sources and on what people are currently doing. Consequently, the valuation of noise needs to take into account the type of area and the time of day” (Wietschel & Doll, 2009, p. 576). To what extent such impacts are relevant external costs depends on how they are perceived, and to which extent they hamper public acceptance of the energy technology. It is possible to use ‘willingness-to-pay’ methodology to quantify the impacts: for example for landscape impacts (visual intrusion) the willingness-to-pay for removing a certain energy plant or equipment can be analysed (Doukas, Karakosta, Flamos, & Psarras, 2011). Another way to calculate the external costs of for example landscape impacts is by examining the impact that energy technologies (e.g. wind turbines) have on the market value of nearby houses (Samadi, 2017, pp. 16-17). For more on this issue, see the section on public acceptance below.

In most cases, climate change and other environmental impacts run in parallel: e.g. technologies that lead to high greenhouse gas emissions often also lead to high air pollution. As shown in Figure

9, wind energy has low greenhouse gas impacts and also low air pollution impacts, while coal has high impacts for both. So, investing in low-carbon energy technologies, or devising emissions reduction policies, usually will have environmental co-benefits. For example, curbing greenhouse gas emissions may lead to air quality improvements and therefore human health benefits, as well as to a reduction in energy-related water demand (Ou, et al., 2018). However, the relationship is not always linear, and can even be counteracting. For example, carbon capture and storage (CCS) can lead to significant greenhouse gas emissions reduction, but may increase on-site and life-cycle water withdrawals. Also, biomass burning may reduce CO_2 emissions, but through its emissions of particulate matter can also have health disbenefits. There are also important trade-offs possible in renewable energy technologies such as onshore wind power. While this technology leads to greenhouse gas emissions reductions and possibly less air pollution, it may have adverse effects on landscape and noise levels.

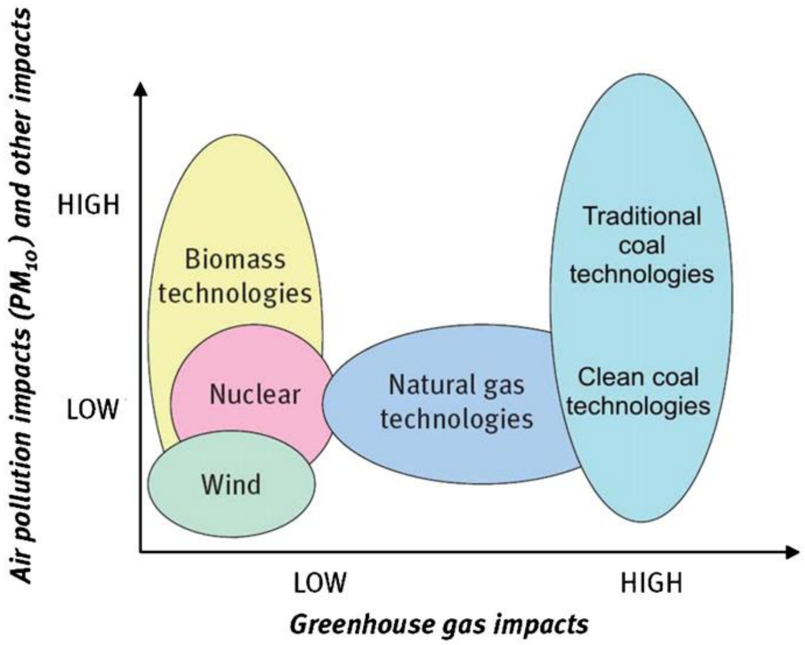

Figure 9. Estimates of climate and other environmental external costs for selected energy technologies (Laes, Meskens, & Van der Sluijs, 2011, p. 5666)

In the STORE&GO project, the external performance of power-to-methane has been analysed on the basis of a set of eighteen environmental impact categories (Codina, et al., 2017; Blanco, et al., 2018; Blanco, 2019). In addition to climate change, these include a wide range of (local) environmental impacts. These impacts have been compared to those of natural gas production, in both cases for the so-called '95 No CCS' scenario, a 2050 energy system scenario with95% emissions reduction, and without using the option of carbon capture and storage (CCS).

The impact of power-to-methane, as compared to natural gas production, turned out to be lower on a range of environmental impacts categories. In addition to the climate change impact, power-to-methane has a relatively low impact on fossil depletion, freshwater ecotoxicity, natural land transformation, ozone depletion, particulate matter formation, photochemical oxidant formation, and terrestrial acidification. On the other hand, power-to-methane has a slightly higher impact than natural gas when it comes to land occupation, freshwater eutrophication, marine eutrophication, and terrestrial ecotoxicity. Natural gas production scores much better than power-to-methane on a few environmental impacts. For most of these (human toxicity, ionising radiation, marine ecotoxicity and urban land occupation) the absolute impacts are however low, and form only a fraction of the corresponding impact of the overall energy sector (Blanco, 2019, p. 33). More significant are the impacts of power-to-methane on water depletion and metal depletion. The metal depletion for power-to-methane is much higher than for natural gas production, as a share of the construction of upstream electricity production (e.g. wind turbines) is allocated to the power-to-methane plant. “Water depletion is also expected to be higher since that is the main source of hydrogen for electrolysis, while natural gas production requires limited water use” (Blanco, 2019, p. 32).

4.3 Externalities: safety aspects

Hydrogen has a reputation to be unsafe, mostly as a result of the Hindenburg disaster of 1937 (Griessen & Züttel, 2009). The hypothesis of this zeppelin disaster being caused by hydrogen has been disproven, but hydrogen retains its image of a dangerous fuel. Nevertheless, hydrogen is a very flammable gas and safety issues are relevant.

Hydrogen is colourless, odourless, and not detectable by human senses. A hydrogen-air-oxygen flame is colourless. Hydrogen is highly flammable if mixed with an oxidiser such as oxygen. The primary hazard of hydrogen is therefore the risk of inadvertently producing a flammable or detonable mixture, which could lead to a fire or detonation. In addition to these dangers, there is also an occupational hazard for personnel that is present during hydrogen leaks in terms of asphyxiation: the hydrogen gas can displace the oxygen in the air. Because hydrogen is not detectable by human senses, it is important to install hydrogen gas detectors. As there is a longstanding experience with handling hydrogen in industry worldwide, there seems to be sufficient knowledge on required hydrogen safety precautions.

Askar, et al. (2016) investigated the safety characteristics of hydrogen, specifically the potential explosion risks when admixed into natural gas. They concluded that adding up to 10% hydrogen to natural gas has nearly no effect on safety characteristics, and “even adding 50% hydrogen to natural gas has only slight effects on these safety characteristics” (p. 402).

5 Studies on quantifying system costs and benefits (quadrant III)

5.1 System costs and benefits: quantifying electricity grid costs

An important aspect of the energy transition is electrification. Currently, about 22% of the EU energy system consists of electricity. Although society is heading for a substantial increase of the role of electrons in the energy system, the role of energy molecules is likely to remain important if not dominant, even after 2050. The EU Energy Roadmap (European Commission, 2011), which is based on the 80% EU 2050 mitigation target, for instance projects a 2050 share of electrons of 38% at most, as illustrated in Figure 10.

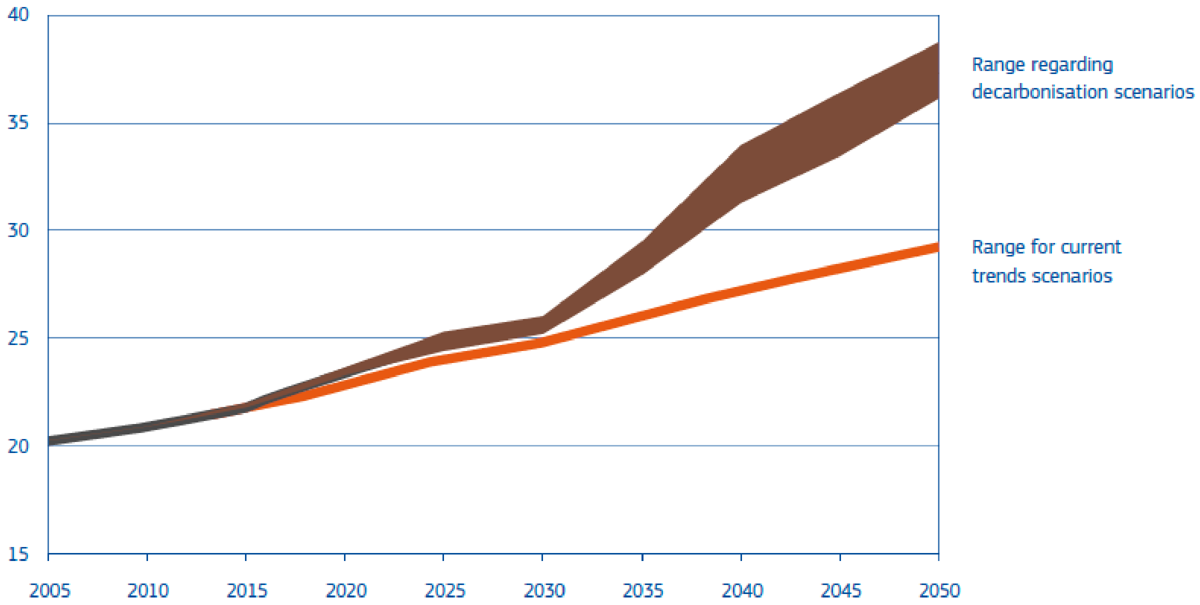

Figure 10. Share of electricity in current trend and decarbonisation scenarios, as percentage of final energy demand in the European Union (European Commission, 2011, p. 7)

Scenarios of substantial electrification imply massive energy transport, storage, and public acceptance costs. To just give an idea of the order of magnitude, assume, inspired by the Roadmap projections, that by 2050 some 650GW wind and some 2,000GW solar capacity has been installed next to a considerable EU hydro and nuclear capacity. Together, this capacity could generate some 7,500 TWh power per annum. With most 2050 EU energy demand scenarios ranging between 9,000 and 13,000 TWh, this 'domestic' EU carbon-neutral power supply could deliver about three quarters of the 2050 EU energy uptake; the rest needs to be imported.

If one would disregard the option to convert part of the projected power supply mentioned into energy molecules, the resulting electrification of the energy system would require an enormous extension of the electric infrastructure. To balance the system it would moreover require costly storage facilities for power of around 1,000 TW. All this would substantially increase energy costs for end-users. No wonder that recently several studies estimated the extra costs for EU taxpayers/energy users to be several hundreds of billions of euros annually. To illustrate, Eser, et al. (2018) estimate that upgrades to electricity transmission lines will cost in the order of 800,000 Swiss francs or almost € 750,000 per km. These costs may even turn out to be much higher, especially in densely populated areas, because of lengthy permitting and stakeholder engagement processes, and public resistance.

The costs of the extension, improvement, and maintenance of the electricity grid, including both transmission and distribution networks, as well as of storage facilities, are clearly part of the 'system costs' of the energy system. With a choice for electrification, including large-scale deployment of wind and solar power, the electricity infrastructure costs will be very substantial in the coming decades. When instead choosing for optimising the energy system cost-effectiveness by including an alternative option, such as power-to-gas, savings on these grid costs and on storage costs may be possible (compared to the electrification option), by converting part of power supply into (easily and cheaply storable) energy molecules and using existing gas infrastructure rather than additional power infrastructure, or even investing in new hydrogen transport systems. This is why energy grid and storage costs, and possible savings on these, are an important aspect to consider when selecting energy technology options for the future.

A recent report by Bothe and Janssen (2019) has tried to analyse how much savings could be achieved if energy would be transported via the gas grid rather than the electricity grid. Savings were expressed not only in transport costs per se, but also in other benefits to the energy system, such as storability of energy, security of supply, and public acceptance. The study, that was carried out for eight European countries, clearly shows the advantages in virtually all respects, although their scope differs from one country to the other. By comparing an 'electricity and gas infrastructure' scenario with an 'all-electric plus gas storage' scenario, savings per capita per year for each country have been assessed for the year 2050. The figures ranged between about € 100 to some € 300.

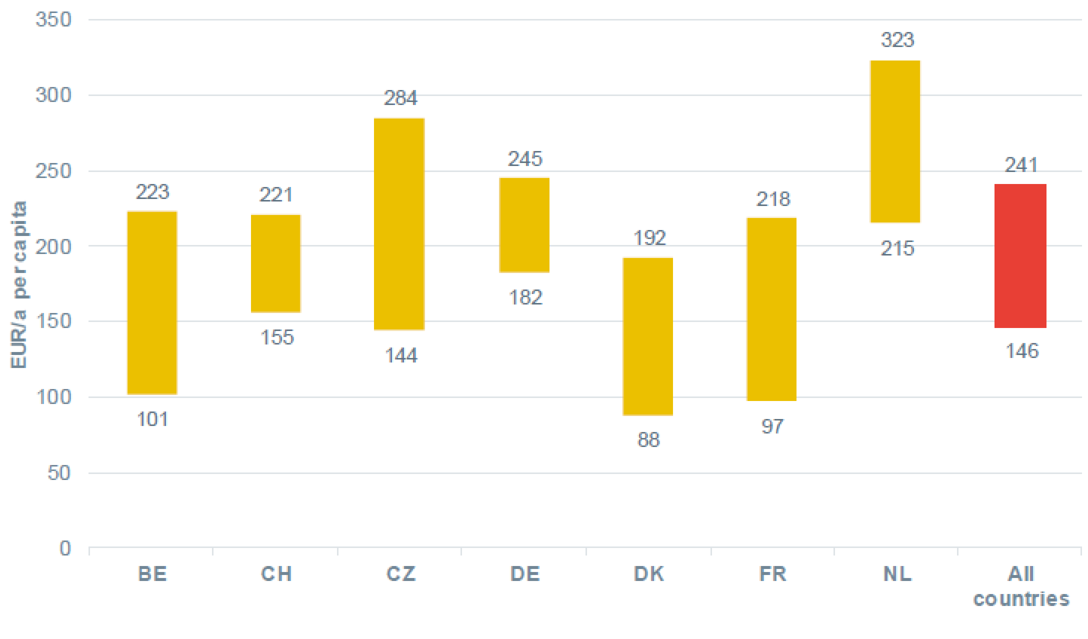

Figure 11. Annual cost savings in € per capita of the continued use of gas in the countries analysed in 2050 (Bothe & Janssen, 2019, p. 42)

Extrapolating these findings to a cumulative figure that would apply for the EU-28 plus Switzerland in total, led to the conclusion that approximately € 1.3 to 2.1 trillion would be saved between today and 2050 (Bothe & Janssen, 2019, p. 40). In this study, the major part of the cost savings (up to 48%) was due to the fact that gas-based end user applications could be maintained for heat, industry, and transport. In addition, net savings on the grid itself amounted to about 24% of the savings. Up to 28% of the predicted savings could be due to cheaper energy generation, although the uncertainty margins were considered to be quite high for this category, depending on the availability of relatively low-cost green gases.

5.2 System costs and benefits: balancing and flexibility

Apart from the issue of costs, substantial electrification in the energy system also has to be assessed in terms of flexibility and balancing energy generation and consumption. Especially considering that the "proportion of electricity generated from uncontrollable renewables (wind and solar) and inflexible nuclear plants is rising rapidly in many countries", the need for flexibility technologies is increasing. This may encompass flexible generation, energy storage, or demand-side response (flexibility options), or reinforced networks and interconnections to shift supply across space and ease balancing (Castagneto Gissey, Subkhankulova, Dodds, & Barrett, 2019, p. 685).

Bompard, et al. (2017, pp. 29-30) state that power-to-gas can provide the energy system with more flexibility ("possible shift from electricity to gas and vice-versa") and reduce curtailment of renewable energy production. Bompard, et al. (2018) used a model to identify the impact of power-to-gas plants on the electricity system. Based on three network models representing the transmission grid, the conclusion is that power-to-gas "helps the transmission networks by absorbing the RES variability" (p. 37). Using a 2017 scenario, a set of power-to-gas plants could reduce the duration of renewable energy imbalance effects by 92%. In scenarios for 2030 and 2040, this effect slightly reduces.

Bothe and Janssen (2019), mentioned before, also tried to quantify the benefits of a continued use of the gas infrastructure as compared to electrification by focusing on the costs of gas storage as compared to other energy storage modalities. Although Figure 12 suggests that the costs of battery storage will decrease significantly in the coming decades, the costs of gas storage will remain much less per unit of energy. Also other storage options, such as flywheel energy storage or compressed air storage, remain unsuitable for seasonal storage because of their high investment costs, low energy density and/or high self-discharging rates. Demand-side management is also considered insufficient to bridge longer-time flexibility needs (Bothe & Janssen, 2019, p. 35).

Specifically for electricity distribution networks, the addition of the power-to-gas option could alleviate network problems. Without power-to-gas, such projected problems include reverse power flow, overcurrents, and overvoltages. Bompard, et al. (2017) estimate, based on modelling exercises, that by including power-to-gas the reverse power flow can be reduced by 67-98% in various situations. "In conclusion, it can be said that the addition of [power-to-gas] systems in a distribution network can improve the stabilisation of the network even for very high (even extreme) penetrations, thus increasing the ability of a network to host a higher penetration of intermittent generation" (Bompard, Bensaid, Chicco, & Mazza, 2018, p. 74).

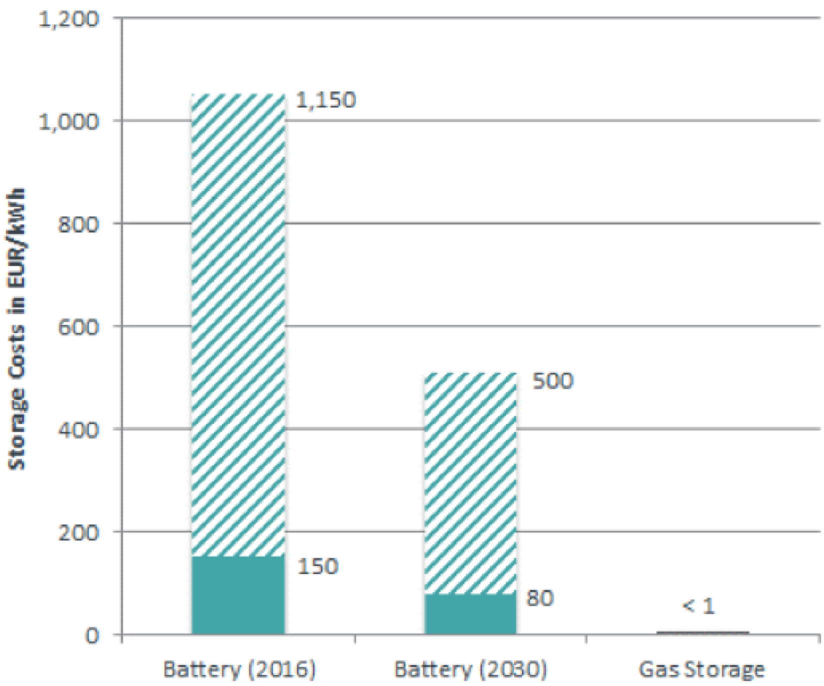

Figure 12. Comparison of battery and gas storage costs (Bothe & Janssen, 2019, p. 35)

6 Studies on quantifying generic externalities (quadrant IV)

6.1 Generic externalities: energy security

'Energy security' has been defined and conceptualised in different ways. Originally focusing mainly on security and continuity of (oil) supply, nowadays the meaning has been extended by, sometimes, using the four As: availability, accessibility, affordability, and acceptability (Glynn, Chiodi, & Gallachóir, 2017; Duan & Wang, 2018). In the STORE&GO project (Van der Welle, De Nooij, & Mozaffarian, 2018, p. 9), the definition for energy security used was "low vulnerability of vital energy systems." In this case vulnerability relates to its exposure to risks and resilience, i.e. its ability to withstand diverse unforeseen disruptions, while vital energy systems are systems whose failure may disrupt the functioning and stability of a society.

Van der Welle, et al. (2018, pp. 23-24) specified seven indicators for assessing the energy security of Europe. These include: the share of energy that needs to be imported, the costs of imported gas, the diversity of energy generation sources and technology, the energy intensity, and the presence of spare capacities for energy generation. Together, these criteria define the sovereignty, resilience, and robustness of the energy system.

Duan and Wang (2018, p. 95) indicate that climate policies usually have a positive effect on energy security, because renewable energy generation typically decreases dependence on energy imports. In addition, they argue that "it is prominently cost-saving to consider the goals of climate change, energy security and local air pollution simultaneously."

The continued use of gas infrastructure has significant benefits, not only in terms of costs (see Chapter 5), but also in terms of security of supply. To illustrate, gas storage capacity in North-Western Europe "is sufficient to cover average gas demand for more than three months. In comparison, today's total electricity storage suffices only to meet the average electricity demand for fewer than four hours" (Bothe & Janssen, 2019, p. 60). Also the highly integrated European gas system and the diversified sources of gas supply add to the superior security of supply of energy as compared to what an electricity-only infrastructure could deliver.

Using the JRC-EU-TIMES model, Van der Welle, et al. (2018) have analysed the energy security effects of three possible future scenarios with power-to-gas: a 'realistic' scenario with several factors that favour power-to-gas, an 'alternative' scenario with a focus on CCS and several constraints to power-to-gas, and an 'optimistic' scenario with the most favourable set of conditions for power-to-gas.

In all scenarios, the import dependency will reduce significantly over time, from 55% of total primary energy supply in 2015 to (almost) 0% in 2050 in the realistic and optimistic scenarios. However, also if these scenarios are run without the power-to-gas option, the import dependency reduces to almost zero, so this is an effect of higher renewable energy shares rather than of the introduction of power-to-gas. Import dependency remains relatively high at about 18% in 2050 for the alternative scenario, as shown in Figure 13. The key reason for this is the large-scale availability of CCS, which leads to higher coal and LNG imports (as their emissions can be undone by capturing and storing the carbon). Even though the natural gas price is expected to rise significantly in the coming decades, the costs of imported gas will decline in all scenarios, because the volume of imported gas decreases. In short, from the sovereignty perspective the energy security in the EU is expected to improve significantly. Including or excluding power-to-gas in this analysis only has a limited effect, however.

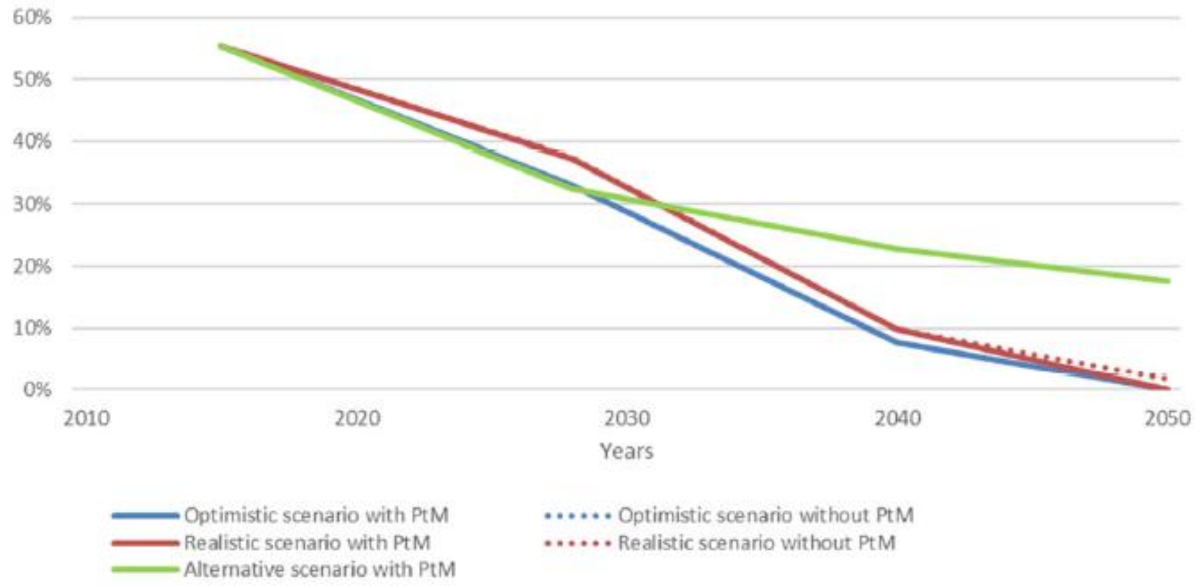

Figure 13. Imported energy as fraction of total primary energy consumption (Van der Welle, De Nooij, & Mozaffarian, 2018, p. 30)

In order to analyse the energy diversity in future scenarios, Van der Welle, et al. (2018, pp. 32-33) used the so-called Shannon-Wiener Diversity Index. Using this index, it is concluded that the energy diversity will be comparable by the year 2050 (about 2.00 on the index) to the current level, although the pathway towards 2050 will be different in each scenario. The impact of inclusion of power-to-gas in the various scenarios is negligible.

Another indicator of the resilience of the energy sector is the energy intensity, i.e. “the amount of energy used as fraction of GDP” (Van der Welle, De Nooij, & Mozaffarian, 2018, p. 36). Up to 2050, the energy intensity will decline in all analysed sectors (agriculture, commercial, industry, residential, and transport) and for all scenarios. There are no significant differences between scenarios with or without power-to-gas.

The final indicator of energy security is the robustness perspective, i.e. “the presence of spare capacities for electricity generation” (Van der Welle, De Nooij, & Mozaffarian, 2018, p. 37). The installed generation capacity is expected to grow faster than the peak load. However, as most of the additional power generation capacity consists of weather-dependent renewables, much of the new capacity will have relatively low capacity factors. In general, the spare capacity for electricity generation is expected to grow in all scenarios. The robustness in the realistic scenarios and in the optimistic scenario with power-to-gas is expected to be slightly better than in the optimistic scenario without power-to-gas or the alternative scenario.

Overall, based on the various indicators for sovereignty, resilience, and robustness, the energy security of the EU is expected to improve towards 2050 in all scenarios. The effect of including power-to-gas in the energy system appears to be limited, with no obvious positive or negative effects. One additional energy security issue for which power-to-gas does lead to improvement, however, is that of price fluctuations and price uncertainty. Scenarios with power-to-gas have more energy storage, and therefore less scarcity during periods of low intermittent renewable energy generation. This leads to less price shocks and more certainty. It is therefore concluded by Van der Welle, et al. (2018, p. 54) that power-to-gas is not a main driver of energy security, but that it can still have a clear positive value. However, that “value lies outside the investors, potentially leading to underinvestment in this technology.”

6.2 Generic externalities: impacts on the overall economy and competitiveness

Choices made for the energy system, such as for certain energy generation or conversion technologies, also impact the wider macro-economic system. There may be effects to the national or regional GDP, but also, for example, to poverty levels, employment, and economic competitiveness and innovation. For the impact on the competitiveness and innovation, it is of importance whether a government decides to support a technology throughout its development, including the 'valley-of-death', or rather takes a 'wait-and-see' approach. Although waiting may incur less costs, as a country or region can benefit from innovations taking place elsewhere, it also means that the same country or region foregoes its opportunity to become an innovative world leader benefitting from higher employment and profit in the longer term.

A common characteristic of the evolvement of new technology is that it passes through a number of stages before reaching maturity, i.e. a technology readiness level (TRL) at which the technology can be considered commercially feasible. Typical components of the technology development cycle are: the laboratory stage, the pilot stage, and the demonstration stage. During these stages, experience is gained with the technology such that costs will decline towards a maturity level. Such costs decline due to: *learning* (removing inefficiencies and the impact of economies of scale, as more devices can be produced and installed which reduces their cost price among others because fixed costs are divided over more units), due to *upscaling* (larger devices lead to cheaper production costs per unit of output), and sometimes due to more *international competition* (e.g. competition from low-wage regions reduces monopoly margins that existed in earlier stages). All in all, costs can come down considerably, sometimes in a limited period of time.

As far as the learning rate is concerned (which is still disregarding the impact of upscaling and more competition), Figure 14 may serve to illustrate that the impact of learning can be impressive indeed when it comes to green energy technologies. The figure shows that, although the annual learning rate commonly shows a wide variation, the average rate for new energy technologies ranges between about 10 and 20% (median 13%).

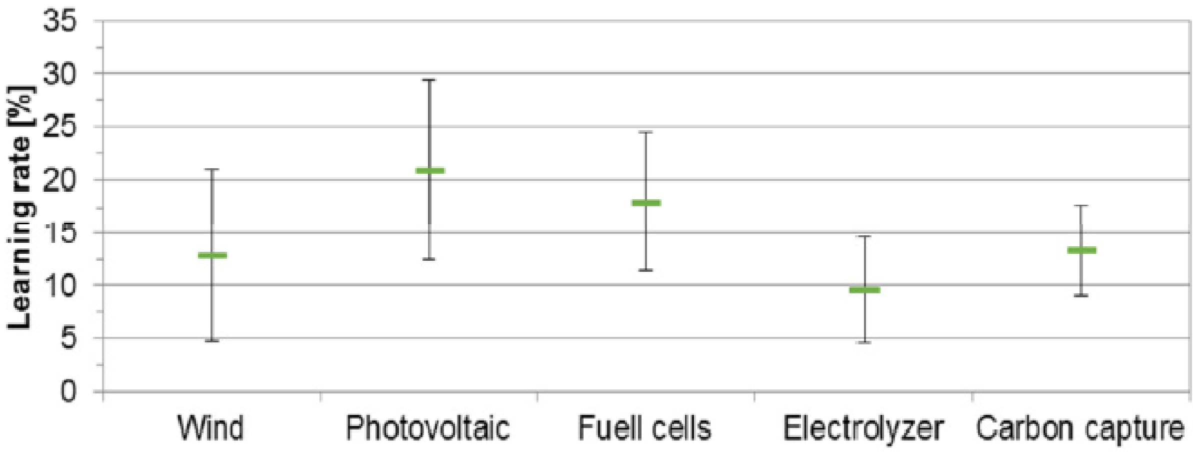

Figure 14. Overview of the mean learning rates of the considered technologies (Böhm, Zauner, Goers, Tichler, & Kroon, 2018, p. 36)

Learning curves for electrolyser systems have been projected in Figure 15.[4] The underlying calculated learning rates all show a slightly declining trend towards 2050, but range between 17% (2017) and 12% (2050) for PEM electrolysers; between 13% and 11% for Alkaline electrolysers; and between 16% and 11% for solid oxide electrolysers.

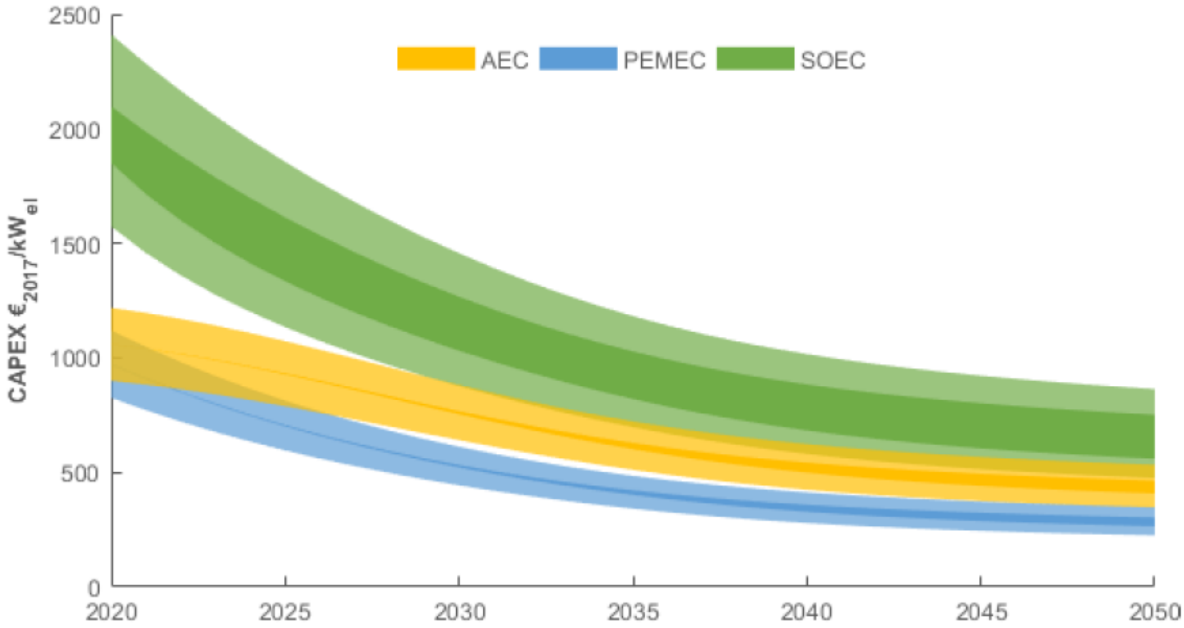

Figure 15. Resulting learning curves for electrolysis systems with an uncertainty of ±15 % on initial CAPEX (light-coloured areas) (Böhm, Zauner, Goers, Tichler, & Kroon, 2018, p. 109)

What are the implications of such massive learning for the cost of 5MW electrolysers per kW capacity? This is shown below in the table that has been derived from the data used in the above figure: between 2017 and 2030 the costs have come down by roughly half; something similar is expected to happen in the period between 2030 and 2050.

Electrolysis system	Calculated costs [$€_{2017}/kW_{el}$]			
	initial (2017)	2020	2030	2050
PEMEC	1,200	971 – 973	522 - 532	265 – 303
AEC	1,100	1,058 – 1,059	754 - 767	408 – 464
SOEC	2,500	1,850 – 2,100	1,031 – 1,266	560 – 751

Table 2. Summary of the calculated cost reduction potential for 5 MWel electrolysis systems (Böhm, Zauner, Goers, Tichler, & Kroon, 2018, p. 95)

[4] These results have been derived on the basis of a component-based modelling approach established by Böhm, et al. (2018), estimating the learning effects on each of the individual components of a electrolysis system. This so-called CoLLeCT model allows for: a comparison of learning effects between different technologies; investigation of the cost structure development at the stack/reactor and system levels; and the consideration of spill-over effects from concurrent technology sectors.

As was argued before, the above data only reflect the impact of learning on costs, not of upscaling or enhanced international competition. In actual practice therefore electrolyser costs will come down more and probably faster than projected in the above table. First, much larger electrolyser units will be introduced up to electrolysers at GW scale, and second if green hydrogen develops into a substantial part of the energy system of the future, the number of producers of electrolysers will obviously grow considerably and with it the degree of international competition. In fact, now already per kW capacity electrolyser prices are mentioned in industry for much larger units in the order of € 200-300.

Some evidence on what to expect from upscaling electrolyser technology from traditionally small-scale units towards units of 100 MW is shown in Figure 16, which relates to PEM electrolysers (Zauner, Böhm, Rosenfeld, & Tichler, 2019). It shows that – next to the learning effect mentioned above – in addition upscaling may again reduce costs substantially by about a quarter to a third. To what extent enhanced international competition may further add to this price reduction is a matter of speculation in the absence of research on this.

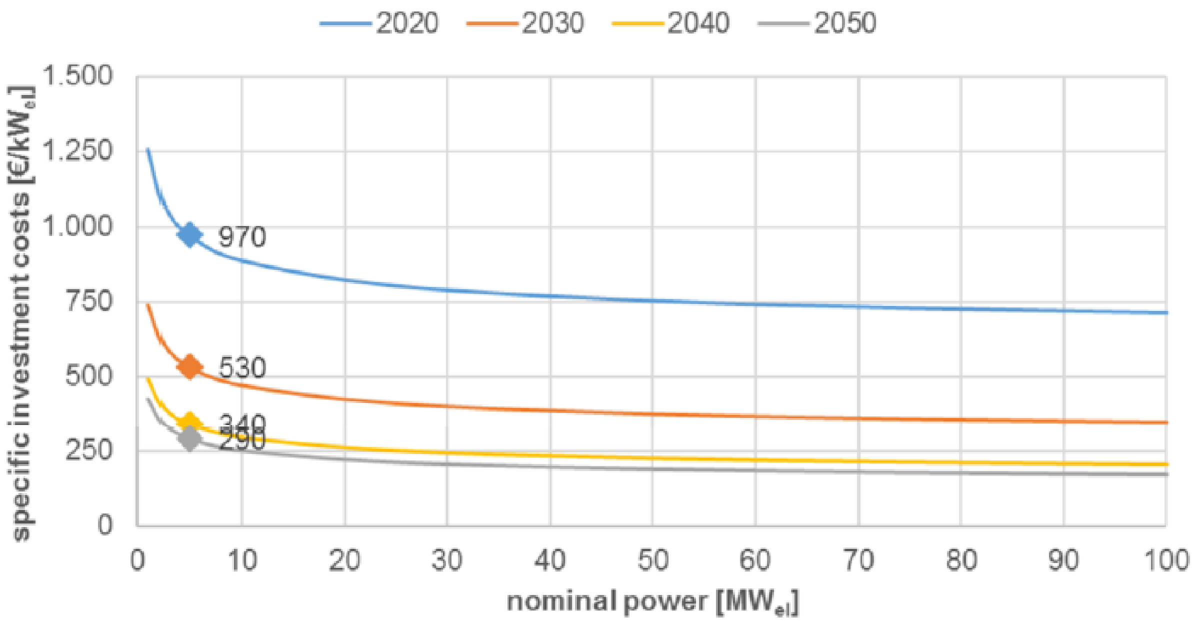

Figure 16. Specific investment costs of PEM electrolyser systems due to economies of scale for a nominal power of 1-100 MW in 2020, 2030, 2040, and 2050 (Zauner, Böhm, Rosenfeld, & Tichler, 2019, p. 17)

Given the crucial role of electrolysers in power-to-gas technology development, and given the substantial scope for its cost reduction as illustrated above, it is clear that first movers in the power-to-gas technologies will face relatively high CAPEX levels compared to players that enter the market in a later stage. Together with the other risks related to producing green hydrogen with the help of electrolysis, namely uncertainty about the future power prices (input) as well as about future returns (output) on the sales of the green hydrogen (and possibly green oxygen), this may scare off investors to step in, and inspire them to rather take a wait-and-see position. This disincentive to act as a frontrunner causes the 'valley-of-death' where a technology, promising as it may be on the longer term, yet will not get off the ground.

Another factor explaining the 'valley-of-death' phenomenon is the logical stages of technology development, usually indicated on the basis of so-called technology readiness levels (TRLs). Technology development usually starts from academic and laboratory stage (TRLs 1-4) via pilot (TRL 5) towards demonstration stages (TRL 6), the last one being the precursor of a system prototype (TRL 7) and towards market maturity (TRLs 8-9). Laboratory experiments on average are typically not extremely costly and are often part or offspring of publicly-funded fundamental research. This implies that there is an innovation gap when it comes to the TRL levels 4-6. Pilots (TRL 5) on average represent a larger investment, but usually several millions of euros will be enough to set up a decent testing facility. Major industries on the whole may be willing to engage in pilots because of the over-seeable amount of resources it requires, especially if carried out in public-private consortia, but without sufficient support even pilots are often difficult to get off the ground. Funding demonstration sites typically requires much larger amounts (in the hundreds of millions), which may explain why, without significant public support, private industries will be reluctant to take the risks. The figure below can therefore be seen as a illustration of the 'valley-of-death' concept. To get through such a 'valley-of-death' therefore requires a clear and convincing set of incentives from the public authorities, persuading the market that the technology will be part of the future under all policy and market regimes. In the absence of such a clear picture, the three effects mentioned above – learning, upscaling, and enhancing competition – will also not materialise and therefore the significant reductions in costs of the technology not achieved.

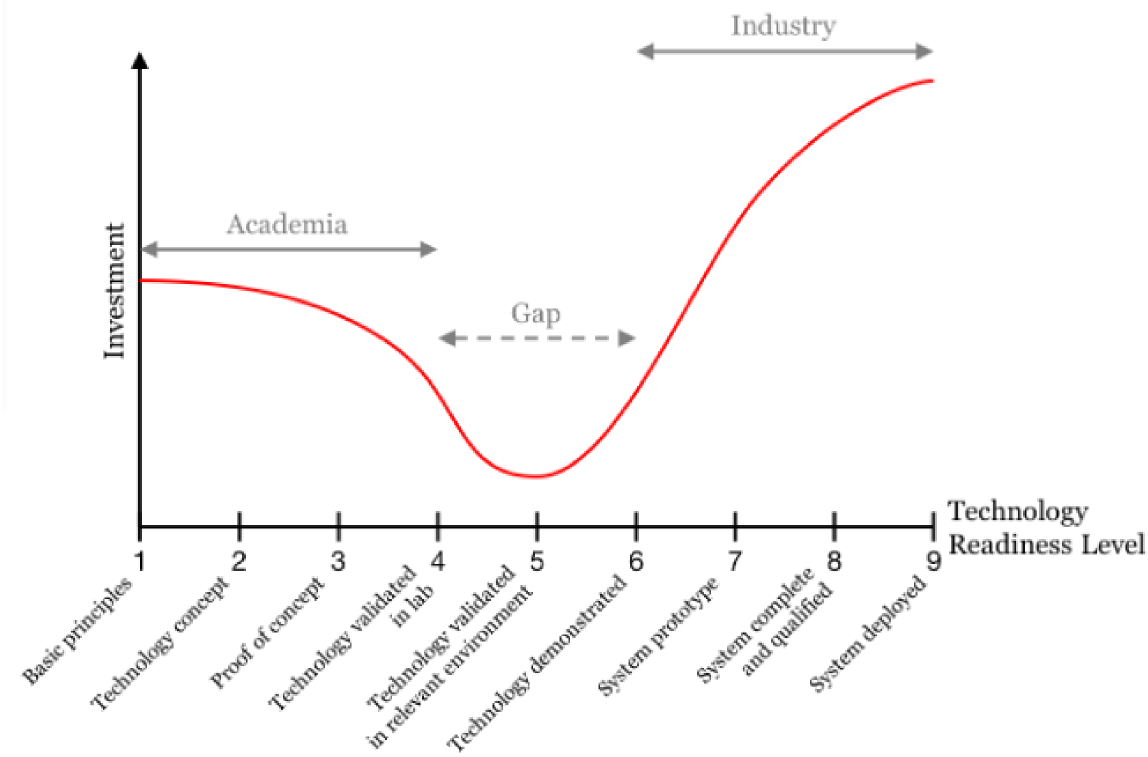

Figure 17. 'Valley-of-death' based on TRL (source: PwC)

Although the hydrogen-related technology is in considerable development during the last years, the figure below (A.T. Kearney Energy Transition Institute, 2014) still may be a nice illustration of how the various sub-technologies related to the hydrogen cycle could be positioned on the learning curve.

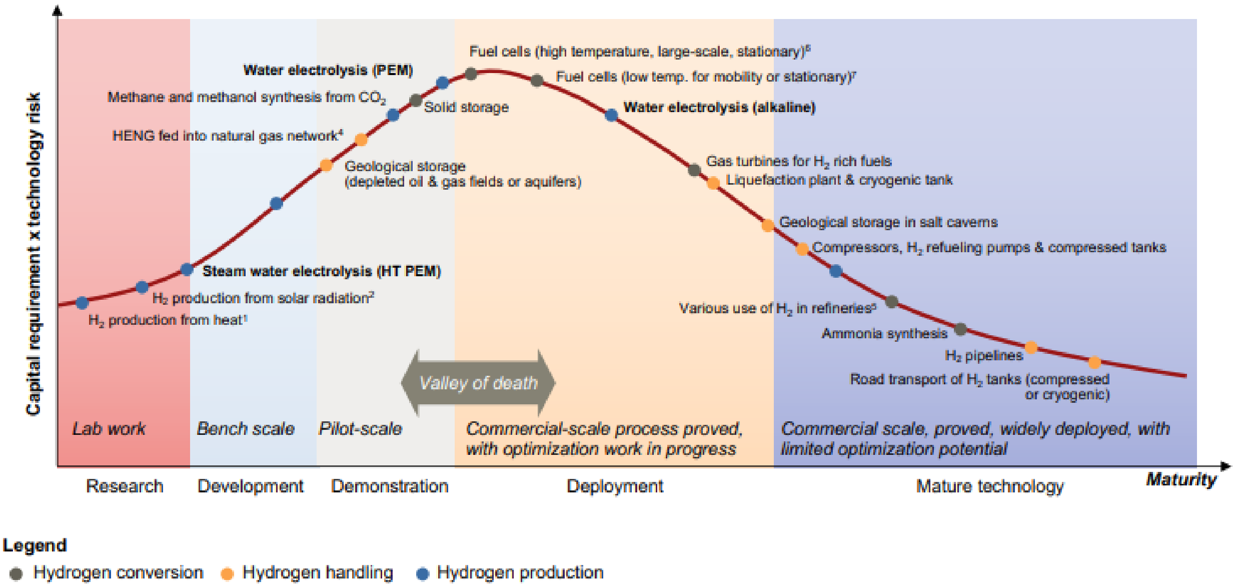

Figure 18. Commercial maturity curve of integrated hydrogen project by (A.T. Kearney Energy Transition Institute, 2014)

The choice for a certain new energy technology often goes together with a government support programme, such as a subsidy policy. As indicated by Bae and Cho (2010, p. S58), a transition from a conventional energy system to a hydrogen-based system requires huge investments, and in order to get private companies to adopt the required technology and invest, “a price subsidy is one of the possible measures in a government supportive policy.” A subsidy policy for hydrogen is expected to require increased taxation, however. This will lead to reduced purchasing power of households: “As the subsidy rate increases, final consumption will decline, but GDP will increase due to the increase in the output of transport, other industries, investment, and export demands” (Bae & Cho, 2010, p. S64).

The energy transition, and the large-scale diffusion of new technologies such as power-to-gas, requires a ‘technological innovation system’. Such an innovation system has several functions, which together influence the performance of the system. Through a successful technological innovation system, a country or region could become a frontrunner in terms of innovation and competitiveness. In a successful technological innovation system, its functions include (Bergek, Hekkert, & Jacobsson, 2008; Andreasen & Sovacool, 2015):

- **Knowledge development and diffusion**, including academic and firm-level R&D, but also activities such as ‘learning-by-doing’.
- **Entrepreneurial experimentation**: “Through risky experiments, knowledge can be collected on the functioning of technology under different circumstances, and reactions of consumers, government, competitors and suppliers can be evaluated” (Bergek, Hekkert, & Jacobsson, 2008, p. 8). This goes further than R&D experiments alone, but also includes experiments with regard to policy and knowledge collection with regard to the functioning of stakeholders in certain circumstances.
- **Market formation**: for many new technologies, a market may not yet exist. Within a technological innovation system, the market can be formed. Initially, competitiveness may need to be formed by regulation through for example subsidies.
- **Legitimation**: a process to overcome the ‘liability of newness’ of a technology and the opposing forces of parties with vested interests, leading to legitimacy for the technology.

- **Resources mobilisation**: the mobilisation of human capital, financial capital, and complementary assets.
- **Development of positive externalities**: positive outcomes of the technological innovation system, that the investors involved cannot fully appropriate the benefits of. Examples may include knowledge spill-overs, increased employment opportunities, and all types of collective, social, environmental, and political benefits.

Based on these functions, Andreasen and Sovacool (2015) investigated the technological innovation system for hydrogen in Denmark. They show that Denmark could become a ‘champion’ for hydrogen systems in Europe, improving national competitiveness, providing high-value jobs, and contributing to societal economic growth. With the expectation that the future role of hydrogen will grow across Europe, countries that work on innovation in an early stage may benefit from a first-mover advantage. The authors expect that a significant percentage of European investment in for example hydrogen fuelling stations will be in Denmark, because of its early investments and therefore leading companies in the field.

6.3 Generic externalities: public acceptance and human behaviour

“Social or public ‘acceptance’ is defined as a positive attitude towards a technology or measure, which leads to supporting behaviour if needed or requested, and the counteracting of resistance by others. Acceptance that only covers an attitude without supportive behaviour may be described as ‘tolerance’” (Hofman & Van der Gaast, 2014, p. 3). For a momentous shift such as the energy transition, public acceptance is of vital importance, so that technologies can live up to their technical and economic potential. Hofman and Van der Gaast (2014) identified five elements that should each be assessed positively by the public in order to lead to acceptance of a technology or project:

- Awareness of climate change and knowledge of clean technologies;
- Fairness of the decision-making process (procedures are considered to be fair when they are open and transparent, the public and stakeholders have a voice in decisions, and these inputs are given consideration by the decision makers);
- Overall evaluation of costs, risks and benefits of a technology (rationally, but also taking into account emotions, ethical questions and social needs);
- Local context (while the public has a positive attitude towards clean technologies and measures in general, individual projects or policies regularly face resistance from the local community);
- Trust in decision-makers and other relevant stakeholders.

Big projects as needed for electrification of the energy system, including large-scale expansion of the electricity grid, have been significantly delayed in recent years as a result of public resistance and long licensing procedures. Resistance is often a result of the local context, where citizens resist the construction of large-scale energy infrastructure that intrudes on the local landscape (visual intrusion or ‘landscape pollution’), but it is also related to mistrust in energy infrastructure companies or government authorities, or a feeling of a lack of public participation and influence. With continuing electrification, Bothe and Janssen (2019, p. 63) expect the electricity peak demand to increase by a factor 3 by 2050, resulting in the need for even greater electricity network expansion.

A factor that adds to the much higher level of public acceptance of gas infrastructure than of electricity infrastructure is not only that the gas infrastructure is already existing unlike the electricity infrastructure that will need to be expanded. Also, the gas infrastructure is commonly underground, unlike electricity infrastructure, and therefore does not face resistance as a result of landscape impacts. Furthermore, gas pipelines require a much smaller land strip, i.e. by a factor of about 50 for similar capacities, given the limited transport capacity of the overhead transmission lines and the wide protective strip for transmission lines as compared to underground gas pipelines (Bothe & Janssen, 2019, p. 63).

Specifically on power to-gas, according to Azarova, et al. (2019, p. 5), “the social perspective and the acceptance (…) are often left uncovered.” Through a survey among 2,000 people in Germany, Austria, Switzerland, and Italy, they have attempted to quantify and analyse the acceptance of new energy technologies, including power-to-gas. The results in each of these countries show that changes to the energy system that include solar PV and power-to-gas are generally well-received as compared to the status quo, while changes including gas power plants or overhead power wires would decrease acceptance. It is also found that certain demographic groups, including women, the elderly, part-time employed persons and lower educated people, are comparatively less likely to support any change to the energy system.

7 Internalising positive externalities for power-to-gas

7.1 The nature and magnitude of PtG externalities

In the previous chapters, a range of important externalities – that are linked to PtG uptake – have been discussed. All of these externalities can be (partially or fully) attributed to PtG deployment. The research and analysis performed within the STORE&GO project shows that most of the key externalities identified are positive. This means that PtG deployment has certain co-benefits that contribute to other development goals.[5] Figure 19 repeats the diagram with four quadrants from Figure 3, but now includes the various externalities based on the discussions in chapters 4 to 6.

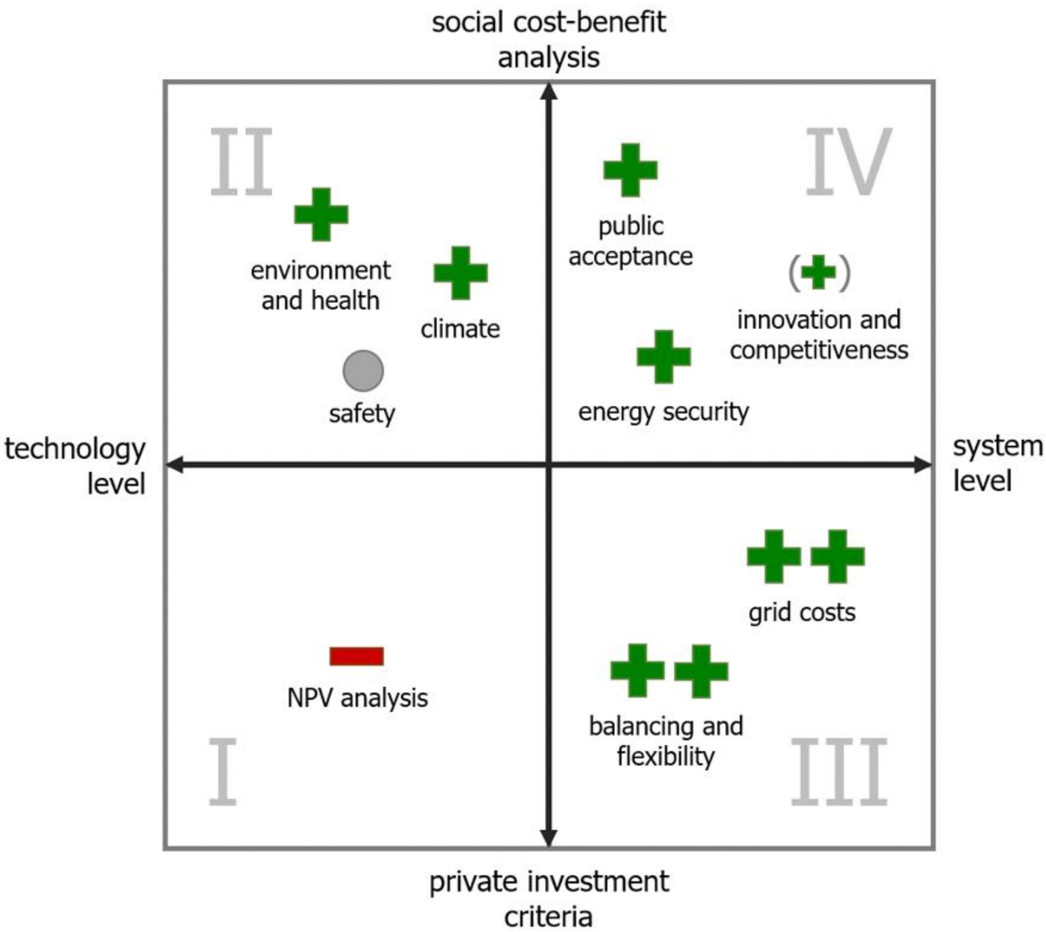

Figure 19. The four quadrants filled with key positive and negative effects of power-to-gas

As discussed in chapter 1, *quadrant I* is a basic assessment by a private investor that considers the company's costs and benefits (i.e. business case) when developing a power-to-gas plant. The NPV modelling exercise as carried out in the STORE&GO project (Van Leeuwen & Zauner, 2018; Van Leeuwen, 2018) shows that, using private investment criteria at the technology level, it is unlikely that the business case for power-to-gas will be positive in the near term. For investors such as energy utilities, the analysis made in quadrant I will determine whether or not an investment in the power-to-gas technology will be pursued. As long as the business case in quadrant I is negative, no large-

[5] We observe that specific configurations of PtG plants, and associated infrastructural changes do not always (and not by default) result in positive externalities. Context specific cost-benefit, life cycle and scenario analysis will be needed to determine both the nature (positive/negative) and magnitude (quantification) of the externalities associated with power-to-gas deployment.

scale investment in power-to-gas will take place, despite the evident potential positive effects of the investment in the other quadrants.

Within *quadrant III* we observe positive externalities in relation to managing and investing in energy transmission, distribution and storage infrastructure. Key ‘beneficiaries’ from these positive externalities are the energy transmission and distribution system operators (DSOs and TSOs). The analysis shows that the development of power-to-gas technology leads to significant positive effects in this quadrant at the energy system level. When it comes to the costs of energy grids, power-to-gas thus has the potential to lead to substantial cost savings, as it helps to avoid additional investments in electricity grid expansion and reinforcements. Instead, existing gas grids and storage infrastructure (after some refurbishment investments) may be used for hydrogen or synthetic methane. This potential cost saving directly links to the positive effect of PtG when it comes to balancing the energy grids, as PtG can absorb large quantities to excess intermittent power supply. Thus, while PtG technology can lead to cost savings for energy system operators, the direct business case for the PtG investor does not change as a result. With the help of energy system modelling (e.g. (Blanco, 2018)) it should be feasible to estimate (quantify) the costs and benefits of PtG within this quadrant.

Quadrants II and IV cover a range of externalities of a more socio-environmental nature. *Quadrant II* includes externalities that are derived from the impact PtG has on energy system emissions (e.g. emissions to air, water and soil). Such impacts are generally quantified with the help of life cycle analysis (e.g. as in (Blanco, 2019)). However, despite a positive contribution of power-to-gas to impacts in this quadrant, again the PtG business case does not improve under the current policy regime. The latter, for example, relates to the design and rules of the current EU emissions trading system (EU ETS). The EU ETS currently does not allocate the economic value of system level CO_2-emissions savings to green PtG projects. First of all a green PtG plant operator does not fall under the EU ETS regime, and secondly there are no mechanisms within the EU ETS that enable a transfer of value to operators outside the ETS system. The externalities within *quadrant IV* generally are more challenging to quantify as the cause-effect relationship is not always obvious or there are many other trends and developments at play. This provides problems (i.e. larger uncertainty ranges) with attributing specific improvements in overall welfare to PtG developments. This is illustrated by (Van der Welle, De Nooij, & Mozaffarian, 2018) who conclude that “power-to-gas is not a main driver of energy security, but that it can still have a clear positive value.”

Despite the various challenges with quantifying and attributing specific externalities to PtG, we do expect that the externalities within these two quadrants will either be neutral or positive (as depicted in Figure 19). We consider for all externalities that the direct business case for PtG does not improve despite providing these positive externalities. (De Nooij, Van der Welle, & Mozaffarian, 2018) corroborate this observation in their full cost-benefit analysis on power-to-gas. They state that: *“Since quite some of the benefits do not end up with the investors in PtG, it is likely that investments in PtG are lower than socially optimal and that government policy aimed at increasing the development and adoption of PtG technologies is welfare improving […].”*

7.2 Internalising positive PtG externalities

With low net present values for investors, the short- and mid-term outlook for large-scale PtG deployment in the EU is unfavorable. Despite the evidence that the technology brings along a range of positive externalities that increase overall societal welfare, a future scenario with considerable underinvestment in PtG can be expected if the policy regime is not changed.

PtG currently finds itself in the technology valley of death (Figure 17), where public support is increasingly falling short to meet the R&D and scaling needs for the technology to grow into a commercially viable and mature solution for the energy market. Externalities are a clear sign of market failure. Hence, in order to bridge the valley of death, additional policy support for PtG will be needed to meet the ambitious energy and climate goals within the EU. Positive externalities of a given technology can often provide a good (political) rationale for policy change. With this we refer to the observation that PtG provides a range of positive services to other systems and stakeholders for which it could (or should?) receive some support. If this is the case, the indirect beneficiaries of PtG could then be 'charged' a fee to generate funds for PtG support schemes. For example, we can argue that – as a result of power-to-gas deployment – the energy network costs are kept to a minimum. These financial savings by network operators could (at least theoretically) be redistributed and used for investing in PtG plants and infrastructure. Similar arguments can be made in relation to the other positive externalities related to power-to-gas. However, in order to (politically) justify such a redistribution of wealth within a society or market system, we consider that at least these three criteria have to be met.

The *first criterion* covers the need for a proven and accepted cause-effect relation between PtG and the expected externality. This means that both research and (preferably) society as a whole agree on the observation that PtG investments positively contribute to a certain impact or goal. *Secondly*, the net impact of the externality should be quantifiable with the help of proven, scientifically robust and/or standardized analytical approaches/methods. This means that for example LCA assessments, and electricity system modelling can be used to estimate the magnitude of a given externality (quantification). *Thirdly*, a robust existing (or precedent) policy framework (that can be amended) is already in place to govern the redistribution of wealth between actors within a market system. This third criterion involves changing 'the rules of the game' (i.e. to amend existing EU directives, rules and regulations) to govern market stakeholders and market systems.

7.3 Three possible policy pathways for PtG

For the purpose of this Deliverable we discuss three possible policy approaches that could be used to *internalize, (part of) the positive externalities* associated with PtG. The *first* policy pathway involves an innovation subsidy for PtG. The *second* pathway considers a portfolio or mixing obligation for suppliers of (renewable) gas to the market. The *third* pathway considers PtG more as a vital component of the energy infrastructure component for grid balancing. Table 3 summarizes the three policy pathways and illustrates the way in which they meet the three criteria referred to in section 7.2.

Criterion	**1 Innovation subsidy** Direct subsidy to support investments in demonstration, pre-commercial and first generation commercial PtG plants.	**2 Portfolio standard** Producers and suppliers of (renewable) gases have to meet a certain performance standard (e.g. blending obligation or portfolio emission standard).	**3 Grid regulation** TSOs and DSOs are allowed to invest in PtG as it is considered as a system service for grid balancing.
Cause-effect relation	Externality – GHG emissions PtG contributes to reducing GHG emissions of the energy system.	Externality – GHG emissions PtG contributes to reducing GHG emissions of the energy system.	Externality – energy system balancing and costs, and energy security of supply PtG contributes to more cost-effective balancing of the electricity grid

			and integration of gas and power infrastructure
Externality quantifiable with help of e.g.	Life cycle analysis	Life cycle analysis	Electricity system modelling
Relevant policy framework(s), e.g.	EU Emissions Trading regulation and Commission Decision 2010/670/EU	EU Renewable Energy Directive 2009/28/EC and EU Biofuels Directive (2003/30/EC)	Commission Regulation (EU) 2017/460 on gas transmission tariffs

Table 3. Three policy pathways to support power-to-gas

While all three policy pathways could meet the same objective (i.e. support PtG uptake in the EU), they all provide a different mechanism through which wealth is redistributed between actors. The aim of this discussion is not to provide a final or conclusive answer to which policy approach is preferred, but to provide input for the policy debate for PtG support. We do this by providing some insights into a) the distributional impacts, and b) some of the anticipated policy design and implementation challenges in the sections below.

7.3.1 Policy pathway 1: Innovation subsidy for power-to-gas plants

Innovation subsidies or grants are a tried and tested policy instrument to provide support to specific technologies. Within the EU, the EU ETS could serve as a mechanism to generate funds for PtG activities. Under the current EU ETS regime, however, power-to-gas plants are not able to monetize any CO_2 savings. This is because PtG plants do not typically fall under the scope of the EU ETS. Nevertheless, the EU ETS can be used to generate funds to support PtG investments, similar as has been done through the NER300 program.

For the NER 300, Commission Decision 2010/670/EU governs *“the monetisation of the allowances referred to in Directive 2003/87/EC for the support of CCS and RES demonstration projects, and the management of the related revenues.”* For the NER300, 300 million EU emission allowances from the new entrants reserve were used to generate funds. The NER300 comprised a 2 bln. EUR funding programme for a range of CCS and RES technologies and with that provides a meaningful reference policy structure for supporting large-scale PtG demonstration projects.

The 2018 EU ETS Phase IV (2021–2030) revision[6] includes an Innovation Fund that basically is an extension of the NER300 scheme.[7] The Fund uses revenues from auctioning 450 mln. allowances for funding innovative projects in the 2020–2030 period. At current market prices for EU allowances, this fund could be over 10 bln. EUR. The first call for project proposals for this fund is expected to be opened 2020, and also targets *“Large scale demonstration of renewable hydrogen production and its use for energy storage (e.g. electrolysis of water coupled with hydrogen storage systems).”*

The Innovation Fund has a number of selection criteria that a project has to meet in order to obtain funding. The selection criteria are:

- effectiveness of greenhouse gas emissions avoidance,
- degree of innovation,
- project viability and maturity,
- scalability,
- cost efficiency (cost per unit of performance)

[6] See: https://ec.europa.eu/clima/policies/ets/revision_en
[7] See: https://ec.europa.eu/clima/policies/innovation-fund/ner300_en

The guiding principles and manner in which these criteria will be applied is stipulated in Commission Delegated Regulation C(2019) 1492 final that was published on 26-02-2019.[8] Within this regulation it is stated that: *"The […] support should depend on verified avoidance of greenhouse gas emissions", and that "[s]ubstantial underperformance on planned greenhouse gas emission avoidance should […] lead to the reduction and recovery of the amount of the support […].*

This suggests that a PtG project proposal for this Fund also has to include a calculation of the expected GHG emissions savings. However, the delegated regulation is not clear on which GHG accounting method should be applied. We consider that an LCA-based approach and protocol to estimate and verify the avoidance of GHG emission reductions is most likely to be used in this framework. During a workshop organised by Hydrogen Europe in the framework of the Innovation Fund on 30 September 2019[9], most respondents from a survey indicated that LCA will play a decisive and key role in calculating and verifying the GHG avoidance potential. However, the exact methodological LCA-approach is yet to be determined (e.g. system boundary, reference / baseline selection, consideration of non-climate trade-off impacts). With several sectors (e.g. hydrogen, fertilizers and refineries) referring extensively to (green or blue) hydrogen as a promising technology pathway a lot can depend on the exact LCA method and rules that will be applied. The LCA studies from the STORE&GO project (Blanco, 2017) (Blanco, et al., 2018), (Blanco, 2019a) can serve as valid input for developing a robust GHG accounting methodology for PtG within the Innovation Fund.

7.3.2 Policy pathway 2: Portfolio standard for (renewable) gas suppliers

A portfolio obligation would affect all suppliers of both renewable and non-renewable gases within the EU. The EU Biofuels Directive (2003/30/EC) introduced the mandatory blending of renewable fuels for transport. Such an obligation could also be introduced for the gas sector. This implies that a certain percentage of renewable hydrogen / renewable methane as part of the total gas supplies has to be supplied to end-users (*e.g. 75% share of renewable gases supplied to market by 2050*). An alternative to this is to introduce an obligation for gas suppliers to meet a certain GHG emission performance for their gas supply portfolio (e.g. max. 15 g CO_2-eq. of life cycle emissions per average unit of gas supplied to market).

To enable both policy pathway varieties, a regime for transparent monitoring, accounting, certification and transfer of renewable energy quota (both for physical and administrative blending) and/or greenhouse gas emissions is needed. Both alternatives imply a more market-based approach where certificates/guarantees, permits or allowances are traded to stimulate production and supply of a 'green' (or 'blue') product relative to an existing 'grey' (or fossil) alternative. For the portfolio blending obligation this can be based on the existing system of Guarantees of Origin (GoO) for renewable gases that allows both physical as well as administrative admixing. Here, a robust system and registry for GoOs for renewable gases is needed at the EU level. A central registry for (renewable) gases, like the European Renewable Gas Registry (ERGaR[10]), also would have to be linked with the EU registry and GoO system for renewable electricity. This is in order to avoid any double-counting, since most PtG plants will eventually run on renewable electricity. In addition, in the event that PtG plants will make use of renewable carbon from biomass-to-energy plants (e.g. captured from biogas or biomethane plants) as a feedstock for methanation, there might be a need to also ensure that certain minimum sustainability criteria (as stipulated in the e.g. Revised Renewable Energy Directive (EU) 2018/2001) are met.

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[8] See: https://ec.europa.eu/clima/sites/clima/files/innovation-fund/c_2019_1492_en.pdf
[9] For more information, see: https://ec.europa.eu/clima/policies/innovation-fund_en#tab-0-2
[10] http://www.ergar.org/

For the portfolio GHG emission performance standard, the policy design has some specific challenges as well. If we assume that for GHG accounting the entire PtG value chain needs to be covered (i.e. a life cycle approach), there might be some issues in terms of GHG accounting and compliance, since part of the supply chain of renewable methane and H_2 suppliers will fall under the EU ETS regime. Considering that ETS GHG accounting does not cover indirect emissions[11] of conventional methane/H_2 production processes there will be a need to extend the current EU ETS monitoring regime so that full life cycle emissions for all (fossil and renewable) gases are accounted for by existing ETS operators and new entrants.[12]

While applying a life-cycle based approach for GHG monitoring and reporting both for renewable and conventional methane/H_2 should be feasible, there are different policy design choices with respect to GHG emission compliance. For compliance purposes a traditional methane / H_2 supplier could buy renewable or low-GHG footprint methane / H_2 to meet its portfolio performance. Alternatively – since the traditional methane / H_2 supplier is likely to fall under the EU ETS regime –, the ETS operator could in principal also be allowed to 'compensate' its surplus GHG emissions by buying additional EU allowances (EUAs). In addition, producers and suppliers of conventional methane / H_2 could also be given the opportunity to compensate (or offset) their own surplus life cycle GHG emissions by purchasing non-EU ETS offset credits through the voluntary market. The latter refers back to the EU Linking Directive (Directive 2004/101/EC) that allowed EU ETS operators to use offset credits (e.g. CERs and ERUs) from project activities for compliance under the EU ETS regime. Here it is positive to note that the interest in non-EU ETS carbon offset schemes in the EU is growing in recent years (e.g. Puro, Finland[13]; Label Bas Carbone, France; Peatland Code, United Kingdom[14]; MoorFutures, Germany[15], and the Green Deal National Carbon market, in the Netherlands[16]). Such schemes could become net suppliers of offset credits.

One possible drawback of a market-based approach – relative to a direct innovation subsidy – is that the price of the tradable certificate or emission allowance can fluctuate in line with market developments. This price uncertainty makes it more challenging to develop a robust business case for power-to-gas. Although the ETS market is relatively mature and liquid, the EU markets for non ETS offset credits as well as for guarantees of origin for renewable gases are still in its infancy stage. In addition, a choice has to be made what the scope and coverage of this quota obligation scheme will be. Will it only target captive production and supply of renewable gases? Or will it also cover non-captive capacity? While natural gas and biomethane (upgraded biogas) are generally produced and sold under open market conditions (i.e. via the public grid), the bulk of synthetic renewable gases and hydrogen use in the EU is supplied to industry via captive production capacity.

7.3.3 Policy pathway 3: power-to-gas as part of energy network service

The third policy pathway considers PtG plants as part of the energy network infrastructure. As such PtG can be seen as a system balancing service for the electricity grid (i.e. the gas system absorbs the 'overflow' of the electricity system). With ongoing energy network integration (gas, electricity and heat) there will be an increasing pressure on energy network operators to develop novel and cost-

[11] Note: only some categories of indirect emissions (e.g. in relation to electricity use) are covered under the EU ETS GHG accounting and allocation regime.
[12] This might also require an alternative view on the benchmarking approach for hydrogen and syngas under the EU ETS, e.g. as stipulated in the Sector specific Guidance Document n° 9 on the harmonised free allocation methodology for the EU-ETS post 2020 (link)
[13] https://puro.earth/#section-challenge
[14] http://www.iucn-uk-peatlandprogramme.org/peatland-code
[15] https://www.moorfutures.de/
[16] https://nationaleco2markt.nl/

effective strategies to balance the energy grids. When considering PtG plants as part of the energy network infrastructure – and label it as a service to improve the energy security of supply – network operators (i.e. TSOs and DSOs) will have to be allowed to include the investment and operational costs for PtG plants in their asset base, and factor in these costs in the transmission and distribution tariffs for gas and/or electricity. This can be managed, for example, through Commission Regulation (EU) 2017/460 on gas transmission tariffs.

This 'third' policy pathway implies that the costs for PtG are socialised through the grid tariffs that are charged to all households and industries that are connected to the public energy grids. It is important to recognise that this approach, for example, has quite different distributional implications relative to the innovation subsidy that basically charges EU ETS industries (who have bought the EUAs, and filled the Innovation Fund). This approach to generate funding for investments in clean energy is already used in many different EU countries. For example, most feed-in subsidy schemes for renewable energy in the EU, like the German EEG, have introduced a surcharge (or "Umlage") on the energy transport tariffs. Relevant questions for this policy pathway will be how the CAPEX and OPEX costs will be allocated? Will PtG costs be fully allocated to the electricity transport tariffs only, or also the gas grid? So, would one allocate the costs of the electrolyser units to the electricity grid, and the costs for methanation to the gas grid?

Within the Netherlands, there already is a case that can serve as a reference (or precedent) for this policy approach. With the investment in the 'Green Gas Booster' pilot project in the village of Wijster (the Netherlands), there now is an extra piece of energy infrastructure that manages the 'overflow' or seasonal imbalance of biomethane from the low pressure gas grid to the mid pressure gas grid. This compressor (overflow or booster) station only operates in situations when there is an oversupply of biomethane in the local low pressure gas grid (see this video with more information on the green gas booster). A key rationale for this investment is that within the baseline scenario (i.e. without the Green Gas Booster) all the biomethane produced locally would have to be upgraded to high pressure and injected into the high pressure gas grid to guarantee adequate balancing in the local grid. With Gasunie (TSO) and Enexis (DSO) as partners in this project, one of the policy questions to answer is if and how these costs should and could be divided between TSO and DSO.

The above pilot project tries to find an answer on whether or not this approach (i.e. a modest share of biomethane will be injected into the national grid) will result in an overall lower cost gas system when compared to the reference scenario (i.e. where all biomethane is compressed and injected into a high pressure grid). Building on the notion that PtG could provide a balancing service to the electricity grid; it essentially avoids (or minimizes) investments and costs for expanding the electricity grid. This policy approach requires that energy regulators adjust their approach and start evaluating the 'cost-effectiveness' of investments in electricity and gas infrastructure in combination, rather than in isolation. Here a more holistic (or system integration) perspective that captures both electricity and gas infrastructure (and perhaps later on also heat and biogas infrastructure) to evaluate the cost-effectiveness of energy infrastructure investments is needed.

7.4 Policy adequacy

Supply side measures

All three approaches discussed above can provide a significant positive investment signal for PtG production and supply activities. However, within this paragraph we briefly discuss whether or not these possible policy pathways have the potential to generate sufficient funds for EU wide scaling of PtG.

The Innovation Fund that currently runs for the 2020–30 period has an estimated size of around 10 bln. EUR. While this certainly is a sizeable, the Innovation Fund is open for a broad range of (renewable) energy, CCS and energy infrastructure projects. Within the ongoing energy transition it is likely that PtG projects will likely only be able to claim a modest amount of this Funds' resources. As a result, the current Innovation Fund might have the size and capacity to for example fund a batch of first generation large-scale PtG demonstration projects. Without considerable funding for PtG from this Innovation Fund in the 2020–30 period one may question whether or not the PtG technology will get quickly enough through the valley of death. Aside from the pre-2030 PtG funding challenge, the post-2030 funding needs are even bigger. Large-scale, EU-wide deployment of PtG will be a multi-billion and multi-annual effort (see for example by (Ecofys, 2017)). This effort will be part of the broader transformation of European energy system and at some point could even result in competition for existing funds. To finance such sizeable system transformations, innovation subsidies (policy pathway) especially in the post-2030 period will no longer suffice. For this a portfolio performance standard (policy pathway 2) and/or embedding PtG in the energy network tariffs (policy pathway 3) are likely to be more suitable mechanisms.

While both the quota / portfolio obligation and network tariffication have the potential to generate adequate overall funding for PtG projects and infrastructure; it remains to be seen which of these two policy pathways is considered 'optimal' given the different characteristics of the three main end-use sectors (e.g. industry, transport, heating). Figure 20 provides a conceptual overview of the different supply side policy pathways through time and the different end-use sectors.

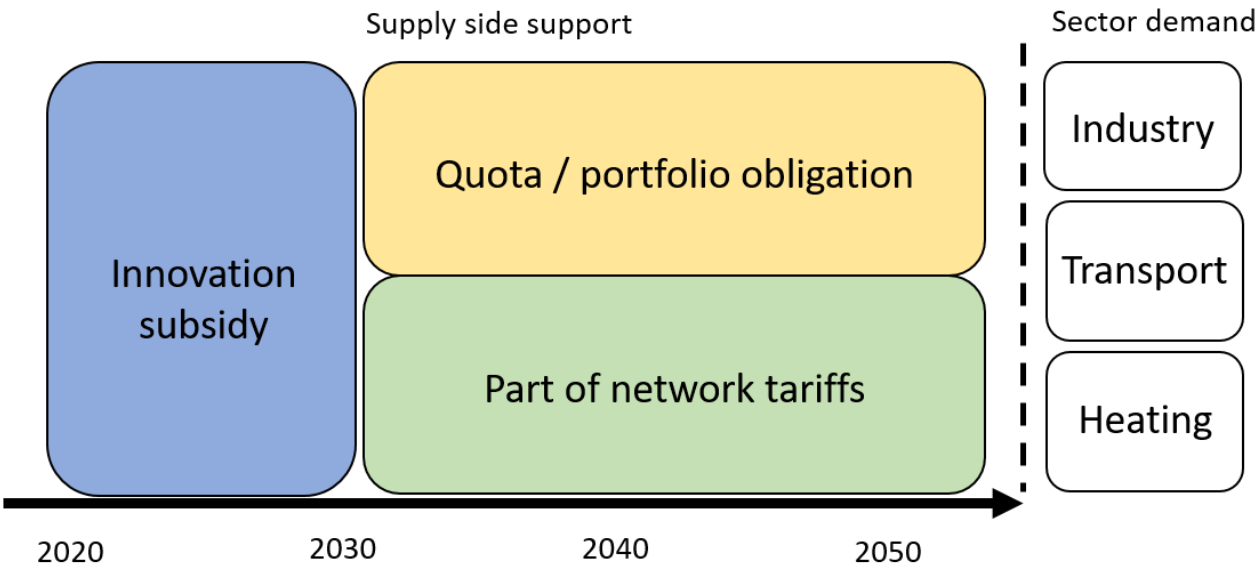

Figure 20. Potential supply side policy pathways and sector demand throughout the 2020-50 period

While the transport sector in the EU is already familiar with a quota or blending scheme, the decarbonization in both the industry and heating sectors is governed differently. Given that the heating sector generally is supplied with (renewable) gases through the public grid, one could argue that it is justified that the costs for PtG investments are embedded in the network tariffs. However, this argument might not be applied in the industry sectors (e.g. steel, chemicals, fertilizers) which are typically supplied with hydrogen/C-gases from captive production and distribution assets. Socializing the costs of PtG investments to directly serve energy intensive industries through the network tariffs might then not be desirable from a social fairness or political perspective.

Regulatory and demand side measures

For any supply side support measure for PtG to be effective we also acknowledge that there is a need for better rules, regulations and technical (safety and quality) standards to enable the production, supply, blending and use of (renewable) gases from different origins (see for example (Kreeft, 2017)). When not addressed adequately and timely such ‘nitty-gritty’ legal definitions and requirements can become an important barrier for PtG implementation and upscaling. On top of that, supply side measures always benefit from parallel measures to increase demand for such gases in the different end use sectors. For example, fuel switching programs in households, car parks, or stricter GHG emission targets under the EU ETS are needed to increase demand for renewable or low-carbon gases.

Level playing field and competition in end use of renewable gases

Economic theory suggests that an open and competitive market improves social welfare. Building on this notion it would be preferable to have a single policy support regime in place that governs the production, supply and end-use of renewable gases for all end-use sectors. A quota obligation scheme could serve as a key support instrument for PtG supplies as it does not discriminate between suppliers and end-users. However, within the existing EU wide natural gas market that is transitioning towards renewable or decarbonized gases, the potential demand for new gases can quite rapidly outstrip production and supplies. In other words, during this transition phase we anticipate that different gas users from different sectors will be competing for renewable gas supplies to match their increasingly ambitious climate goals. With renewable or decarbonized gases as a scarce commodity, under open and competitive market conditions, these gases would be supplied to the end-users that pay the highest premium price. The key question is whether or not a fully open and competitive PtG market will provide the most stable ground for substantial PtG upscaling. If one aims to rapidly develop commercially viable, early stage business cases for PtG; the first renewable methane/H_2 supplies could go to the transport sector, where generally a relatively high (premium) price per unit of energy is paid. However, at the same time bulk supplies to the industry sector could ensure rapid demand increase and volumetric growth in renewable methane/H_2 production and supply. Also, direct supplies to industry from captive production facilities could minimize additional investments in energy transport and distribution infrastructure.

While by 2050 and beyond all three key end use sectors might have switched from conventional to renewable gases, and the entire system is transformed; during the transition phase (roughly from 2020 to 2050) the challenge is to find the least cost trajectory. This premise could provide a rationale to govern the market and gradually open up and expand the market for renewable gases. Such a strategy could ensure that production and supply capacity growth in parallel and is also matched with a timely and targeted infrastructure transformation.

8 Conclusions and recommendations

This report shows that PtG is a technology that has various positive externalities (in quadrants II, III, and IV in Figure 19), while still showing a negative business case (in quadrant I). In order to further the development of PtG, these positive externalities could be monetised in quadrant I to offset the higher costs and/or lower benefits incurred by investors. *"Otherwise, there is a danger that negatively discriminating at the expense of [power-to-gas] may lead to society incurring extra costs"* (Bothe & Janssen, 2019, p. 68). Römer, et al. (2012, p. 494) describe it as follows: *"Widely distributed benefits cause situations of positive externalities and thus lead to the omission of a socially desirable deployment of the examined technologies."* In other words: the benefits are distributed among a variety of actors in all four quadrants, while a disproportionately large share of the costs and risks are born by the investors business case (in quadrant I). This all increases the risk of underinvestment in PtG.

By assessing PtG based on its merits (benefits, opportunities) and drawbacks (costs, risks) in all four quadrants, a level playing field can be created by changing the policy environment. The changes in policy regime should ideally follow a rationale where clear and quantifiable positive (and negative) PtG externalities can be internalised in the business case PtG. As the discussion in Chapter 7 shows, there are different policy pathways that link to specific positive externalities. These policy pathways have the potential to ensure that sufficient funding for PtG is available. We consider the EU's Innovation Fund (policy pathway 1) suitable primarily for the 2020–30 period, where it could fund a first batch of large-scale PtG projects on relatively short notice. We raise our concerns that this Fund might not be sufficient to push PtG out of the valley of death. For the post-2030 period we consider the two other policy pathways (i.e. 2. Quota obligation and 3. PtG embedded in network tariffs) more suitable for generating sufficient funds that could match the EU wide PtG scaling needs. We emphasise that within the policy impact assessments, the distributional impacts are properly identified and (where possible) quantified. The main rationale for this is that with a perceived unfair or uneven distribution of the (financial) burden there could be an increasing resistance to system change.

We recommend that aside from initiating supply side measures to support the building and scaling of PtG demonstration plants, there is also a great need to tackle in parallel specific legal and regulatory issues (see (Kreeft, 2017)), and adopt measures to manage/control demand growth in the different end-use sectors.

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