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Designing policy for sustainable technology

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Designing policy for sustainable technology

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Abstract

Novel technologies are required for energy systems decarbonisation. In many instances, policy intervention will be required to overcome deployment barriers. When should policy intervene, and what form should that intervention take? Policymakers and regulators are struggling with designing the appropriate response as guidance is scattered across many disparate academic fields. Finding little guidance in the literature, this perspective provides a decision framework to navigate the uncertainty. A two-part procedure is formulated. First, a window of intervention is specified conditional on technological constraints and relative cost. Second, we combine disparate guidance sourced from behavioural, political and economic literatures to identify the conditions for intervention and the corresponding corrective policy intervention. We provide a single taxonomy to inform policy. We apply this framework to the design of policy to support the deployment of hydrogen technologies, identifying an intervention strategy for both small technology 'takers' and large technology 'makers'.

Keywords: Clean Energy Innovation**,** Energy policy;

JEL classification: O32, Q42, Q55

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Summary

This paper presents an insight into the feasible deployment of hydrogen technology. In so doing, a more general evaluation framework is developed. The following policy recommendations emerge with respect to hydrogen.

Hydrogen is most likely to be cost-effective post-2030, conditional on high degrees of capital cost reduction

First, the likely cost effective deployment at various milestones may be estimated from the analysis of Sections 3 and 4. By 2030, it is unlikely that the cost of hydrogen will be such that widespread deployment will occur. Most deployment will become cost-effective post-2030. Cost-effective deployment is most likely among transport, electricity storage and industrial applications. For heat, there is a narrow window during which deployment must be initiated due to cost competitiveness and the logistical constraints required to meet 2050 targets. Hydrogen-fuelled heat is unlikely to be cost-effective before 2035. To achieve full decarbonisation by 2050, initiating deployment post-2040 would require a pace of deployment that is greater than that observed for similar transitions in the past, such as when the UK switched from 'town gas' to natural gas.

A greater emphasis on supporting deployment rather than lab-based R&D

For hydrogen, it has been shown that there is greater scope for cost reductions through deployment than lab-based R&D. Many of the areas for which cost reductions may be achieved are associated with production process standardisation and economies of scale. These are lessons best learned through practice and deployment. This is important for policy; given the positive spillover effects associated with innovation, there is an economic motivation to support innovation investments. Given the nature of innovation associated with hydrogen production, innovation policy with the focus of reducing the cost of hydrogen production should be more closely aligned with deployment-related subsidies as opposed to lab-based subsidies.

The operation of pilot plants is key to gain operational experience and optimise system design. Laboratory research is not without benefits and should be focussed on reducing the operating temperature for SOECs and developing new system designs such as PEM stacks for higher pressure or differential pressure operation (important for direct integration with a renewable supply).

Current cost trajectories are predicated on strong deployment.

Achieving estimated cost reductions is predicated on considerable deployment. Much electrolysis must take place before cost-effective deployment is achieved. This may result in 'learning investments' whereby hydrogen is produced at a cost greater than alternatives as this is the most efficient way to innovate. If this is guided by policy supports, these must guide early hydrogen rollout towards areas where the social cost of inefficient deployment is least.

Supporting the reduction of renewable electricity cost is a no regrets policy

It has been shown that the drivers of cost reduction related to hydrogen deployment are capital costs and electricity costs. The recent pace of both capital and electricity cost reductions suggests that electricity cost reductions may play a greater role in achieving cost-effective hydrogen production. Supporting such development is a no-regrets policy; cheaper renewable electricity is required for many purposes. The positive spillover of facilitating cheaper hydrogen production should add greater value to existing policies to support renewable electricity price reductions. Adding extra support to achieve this is therefore a no regrets policy as reduced renewable electricity costs are welfare enhancing regardless of whether hydrogen is adopted or not.

Infrastructural requirements are the primary non-cost barrier that technology takers should anticipate. Phased rollout can be achieved at relatively low cost.

Above all, significant infrastructure investments will be required over the next decades to drive the uptake of fuel cell vehicles and to transition the technology to a sustainable market phase. According to a study by McKinsey & Co. [34], a hydrogen supply infrastructure for around 1 million FCEVs requires an investment of €3 billion (production, distribution, retail), of which €1 billion relates to retail infrastructure. However, such investment need not take place at once, lowering the barriers to deployment. Staffell, Scamman [1] discuss how a phased deployment of fuel cell infrastructure can be implemented at relatively low cost.

While global supply pipelines look promising, local production capacity may pose a deployment constraint

Global production bottlenecks are unlikely to be a pressing policy concern.[2] This does not rule out the possibility of local bottlenecks, especially as production is likely to be geographically concentrated. In the short term, this will lead to economic rents being accrued to producers at the expense of consumers and/or public funding bodies. In the long term, this should give the required signal to expand capacity. Interfering with short-run economic rents is second best policy as it may run the risk of dampening the longer-term capacity investment incentive. The first best outcome is to avoid this capacity constraint.

Policy should anticipate any local bottlenecks, putting in place measures to tackle the source of any identified constraint (e.g. production incentives, removal of barriers to transport/entry; impediments discussed below). This is especially important should a demand stimulus be put in place.

There may be scope for policy to ensure the required social capital is in place. This may be in fields such as to establish business connections and to develop an understanding of hydrogen-based production methods to facilitate adoption in a timely manner.

Policy must correct incomplete markets for emissions and risk

The adoption of hydrogen as part of a decarbonised portfolio of technologies should be guided by technology-neutral policy targeted at specific market failures. To guide emissions reduction, the first-best solution is a target-consistent high and rising carbon price.[3]

There may also be incomplete markets for risk, especially in relation to electricity storage and generation. At best, this may slow down investment. At worst, this may lead to underachievement of policy targets. There is a social value to timely investment and therefore an economic rationale exists to correct for this market failure. This may include investment products and/or price supports that hedge some of the risk associated with electrolyser investment. However, there is a social value to exposing investment to some risk, such that investment in the efficient portfolio of technologies is incentivised. Methods exist to efficiently design such price supports [4, 5]

Investment incentives may be stronger in some markets than others. Liberalised electricity markets tend to have strong incentives and often bespoke markets for investment in generation/storage capacity. Longer-term storage forms part of the contracted capacity as intermittency grows as a proportion of total generation. This should be technology-neutral, with hydrogen-focused policy unnecessary outside of this framework.

Similarly, adoption of hydrogen-fuelled vehicles should be guided by preferences and prices, and technology-specific policy should not distort this decision. While hydrogen is the frontrunner to serve decarbonised HDVs, the relative balance of hydrogen and non-hydrogen LDV and private cars is unknown. The relative balance between electric and hydrogen-fuelled vehicles should be determined by consumer preferences in this instance (see Appendix for full discussion).

Institutional constraints may impede the first-best solutions discussed above. If competing stakeholder interests do not allow for a target-consistent carbon price trajectory, subsidies or price supports are likely preferable to under-investment in decarbonisation.

Fuel cells for HDV transport, limited evidence to suggest domestic and LDV vehicles being cost-competitive with battery electric vehicles

Cost-effective deployment for heavy goods vehicles and electricity storage is most likely to precede cost-effective deployment for light goods vehicles and private cars, with the preceding analysis concluding that it is uncertain whether the latter transport categories could be cost-effectively served by hydrogen, with battery electric vehicles more likely to be adopted.

Firm and household level access to credit may impede timely investment

Investment in dwelling heating/insulation and transport technologies may be hampered by credit constraints. Low-cost loan or pay-as-you-save schemes should form, at least part, of any deployment incentive. Supports should be technology-neutral if multiple technologies may serve a given requirement.

Behavioural biases may impede adoption of transport and heating technologies

Transport and heating technologies are predicated on individual and household-level adoption. The literature has shown that inattention, negative perceptions and unfamiliarity with how they may meet modern heating needs are among the most prominent biases impeding adoption.[6] As section 3 outlines, and the report of Williams, Lohmann [6] alludes to, information campaigns may be a suitable first point to address this issue, followed by the measures identified in Section 3. Hydrogen-based transport may be subject to fewer behavioural impediments relative to electric vehicles as they do not incur many of the negative traits such as range anxiety, etc.

As discussed in Section 3, any environment-centred information campaign should be targeted towards those who are positively pre-disposed to environmental policy and who would invest through environmental altruism. An alternative framing should be adopted for those politically averse to environmental policy.

Distributed seeding of early adopters

Should price supports be offered for heating or transport technologies, 'seeding' such support throughout various social strata, rather than concentrate adoption among a single cohort, may leverage more positive peer effects and lead to greater adoption[7, 8].

1. Introduction

Many low-carbon pathways predict an important[9, 10], yet uncertain[10-14], role for novel technologies (e.g. hydrogen, carbon capture) in energy systems decarbonisation.[9, 10, 15-17] Effective policy must be able to anticipate the trigger point, form and extent of any potential intervention considering institutional, behavioural and economic market failures. Guidance is scattered across disparate literatures; there exists no single decision framework. We present a policy taxonomy that combines the disconnected literature into a single decision framework.[b]

A set of all potential deployment trajectories is first constructed. Potential trajectories are eliminated on the grounds of logistical and technological infeasibility, followed by grounds of cost competitiveness. The second step is to consider the policy intervention. The conditions for intervention and the corresponding policy response are drawn from fields of economics, behavioural science and political science to form an intervention taxonomy which policy may consult.

This framework may be applied to analyse any novel decarbonisation technology, such as electric vehicles, biomass, and carbon capture technologies. We demonstrate this framework using the example of hydrogen-based technologies. Hydrogen emerges as an important energy carrier when there is a great deal of energy systems decarbonisation.[11] The precise role that hydrogen will play is uncertain and predicated on the extent with which technological and economic constraints bind [15, 16], while the appropriate policy response is predicated on the existence of market, behavioural, institutional and political impediments. This paper identifies the trigger points and appropriate response for intervention, conditional on what is known about these constraints.

This perspective considers the optimal strategy for two types of decision-makers. Large countries and international bodies such as the US, the UK and the EU may be considered technology 'makers'; their policy decisions may influence technology cost trajectories. Small countries and regions, on the other hand, may be considered technology 'takers'; their policies are small relative to total deployment and have relatively little direct influence on the cost trajectory.[c]

This paper is structured as follows. First, the general analytical approach is discussed in Section 2. Section 3 outlines the procedure for calculating the window of cost-effective deployment for hydrogen technologies. Section 4 concludes.

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[b] To illustrate, decarbonisation trajectories focus on the technological requirement (e.g. [11]), while much policy advice ignores barriers beyond cost (e.g. [18, 19]) or deals with policy intervention in more general terms [19-22]. In parallel, insights regarding specific behavioural, institutional and political barriers, and the required interventions, are scattered across disparate strands.[23-28]

[c] A technology taker may, however, be able to influence decisions made by technology 'makers'; for example a small EU member state (a technology 'taker') may have influence on EU-level environmental policy.

2. Decision framework

It is the role for policy to intervene should the market fail to deliver timely decarbonisation. This requires an understanding of (1) when such intervention may be required and (2) what form, if any, this intervention should take. Effectively implementing step (2) requires an understanding of the factors constraining timely deployment.

The outcomes that are endogenous to the decision-maker's choice set are predicated on whether they are a technology 'taker' or a technology 'maker'. For a technology taker, the policy response, conditional on a given timescale of deployment, is endogenous. A technology maker has influence on technology costs and therefore the timescale of deployment and therefore both steps (1) and (2) are endogenous to their decision-making process.

This section outlines a systematic framework to navigate this decision process for both types of decision-makers. First technological, logistical and cost constraints are considered, allowing the analyst to identify a window during which deployment is likely to be cost-effective. Second, a review of the literature identifies the specific economic, behavioural, institutional and political barriers likely to affect deployment. A taxonomy of barriers and potential policy interventions is presented. Each step will now be discussed in greater detail.

2.1. Step 1a: Technological and logistical constraints

When identifying a window of deployment, we first specify an upper and lower bound by identifying binding technological and logistical constraints. The lower bound corresponds to technological readiness and any associated 'lead-in' time; deployment before this point is not possible given the state of technological development. The upper bound corresponds to a logistical 'countback' from the policy target; this is the latest point at which deployment may be initiated while meeting the stated target.

2.2. Step 1b: Specifying the cost-effective window.

This deployment range may be further refined by considering cost competitiveness. To maximise societal welfare, deployment occurs when the cost is less than or equal to the social cost of the next-best substitute. The method employed to evaluate cost competitiveness is predicated on the extent with which uncertainty affects the decision-making process. A review of the literature has identified a number of common procedures, presented in Table 1. The analytical procedure is straightforward if the cost trajectory is known, which is particularly likely under a short-term time horizon for a mature technology. Standard cost-benefit analysis methods (e.g. the UK Government's 'Green Book' [29]) may be used to compare the (discounted) costs with those of the next-available policy option.

For many technologies, the cost will be uncertain. The nature of this uncertainty and the decision-maker's attitude to risk will determine the appropriate intervention. A range of potential costs (estimated using methods such as simulation [30-33] or expert elicitation [34, 35]) provides a policymaker with a likely cost trajectory and an associated bound of uncertainty. An appropriate intervention point may be identified conditional on whether the decision maker wishes to follow the most likely outcome or err on the side of caution. Arnold and Yildiz [33] and Chronopoulos [36], for instance, show how the probability of optimal deployment may be identified using these methods. This approach is applied in Section 3.

A decision-maker should use Real options Analysis (ROA) when there is uncertainty in costs and it would be a valuable option to wait. Such an option may be particularly valuable in the early stages of the decarbonisation trajectory where there may be more flexibility in deployment timing. ROA has been employed to determine the optimal deployment of many new energy technologies since Dixit and Pindyck [37] published their important guideline in 1996 (see [38]).

Modern Portfolio Theory (MPT) should be applied when an analyst wishes to efficiently balance system-wide costs and risks, rather than focusing on technology-specific attributes; while an investment may be low (or high) risk, these risks may (or may not) be correlated with those of the system, thereby increasing (or reducing) total system risk. This procedure is particularly useful for energy systems, where consumer costs and the risk of system failure are determined by the portfolio of technologies. MPT may be particularly useful when a considered technology has risk properties that are different from other components of the system. MPT was first developed by Markowitz [39], with Bazilian [40] reviewing applications in the energy sphere.

Despite the application of these frameworks, uncertainty may persist. There may be qualitative considerations that the above frameworks cannot accommodate. Multi-criteria decision-making analysis may be appropriate when various quantitative and qualitative considerations are to be considered in tandem, with Løken [41] providing a review of applications and methods. To navigate the remaining uncertainties, practitioners often follow the precautionary principle and err on the side of early rather than late intervention.

Table 1: Methods to navigate cost uncertainty

Analysis tool	When to apply	Guideline resource(s)
Maximise (risk-adjusted) expected value	Single technology with uncertain cost	Berger [42]
Real options	An important option to wait exists	Dixit and Pindyck [37]
Modern Portfolio theory	Balance of system-wide risk important	Markowitz [39], Bazilian [40]
Multi-criteria decision making	Multiple factors must be considered	Wang [43]

2.1. Step 2: Identifying the policy intervention

A choice set of interventions specific to energy technology deployment are listed in Table 2, covering specific economic, behavioural, institutional, regulatory and political impediments likely to require policy intervention.

Economic impediments

Economic impediments may be divided into (1) production capacity constraints, (2) missing markets and (3) incomplete markets. Production capacity is finite in the short run and pressure in excess of this finite capacity leads to short-term price inflation.[44, 45] In the long run, this should give the required signal to expand capacity. This may occur in the early stages of deployment for a new technology if demand exceeds existing production capacity constraints. If binding production constraints are anticipated, likely if demand exceeds supply in the short run, a further demand stimulus could lead to increased prices rather than a greater pace of decarbonisation.[46] Price supports or investment incentives may therefore prove counter-productive unless policy acts to minimise barriers to capacity expansion. Heflebower [47], Demsetz [48] and Fee *et al.*[49] find that access to inputs such as capital, labour and production facilities, and the removal of unnecessary regulatory barriers, are of greatest importance.[50]

Missing markets for externalities, risk and credit can potentially hamper new technology deployment. A high and rising carbon price, calibrated to that which achieves stated decarbonisation targets (i.e. a 'Pigouvian fee'), is the well-established solution to emissions externalities.[51] Subsidies are often used in practice but are second-best policy.[52] An incomplete market for risk can slow down investment and therefore decarbonisation. As energy systems become decarbonised, operation is exposed to greater intermittency and this exposes investors to risks that can be difficult to hedge with traditional instruments.[53] There are a number of potential solutions. A liquid electricity forward market can provide greater certainty for investors as prices, and therefore revenues, can be secured ahead of time.[54] A liquid market minimises transaction costs and allows a fair price to be settled. If this does not exist – and in many jurisdictions forward markets are illiquid[55] - a forward trading mandate, a capacity market or a price support comprise the potential corrective measures. A forward trading mandate forces liquidity on forward markets, allowing investors to receive a fair price with greater ease, reducing risk. [54] A price support, such as a minimum price guarantee, can also reduce risk. Policy must design any price guarantee such that a fair price is offered and undue burden is not placed on consumers/taxpayers who are often the counterparty to such a guarantee.[4, 5]

Access to credit is a general constraint on investment faced by both firms and households.[56] This may arise due to constraints on what banks can lend[57] or perceived riskiness associated with investment in a novel technology[58-60]. Policy measures should act to counter these market failures and can correct for this through two channels. First, ambitious and credible climate policy increases banks' confidence in the sustainability of the clean energy sector and associated investments, reducing any required risk premia. Secondly, policy should increase financial institutions' capacity to assess and manage risks associated with new and immature low-carbon technologies. There may also be scope for state-sponsored credit or, for household-level energy efficiency investments, 'pay-as-you-save' schemes.[61]

A final, often overlooked, market failure relates to the under-provision of social capital. This encompasses the degree of trust, collaboration, cooperation, as well as bridging and bonding social network ties between economic sectors, research institutions and other stakeholders.[62] While it is possible that innovation and capacity development may progress in the absence of extensive social capital, 'trust lubricates cooperation'.[63] For instance, a network of knowledge exchange and/or stakeholder engagement has been shown to facilitate greater adoption of sustainable technologies.[64, 65] Facilitating such a network can reduce institutional barriers to adoption.

It is difficult to pinpoint whether a lack of social capital is an impediment to technology adoption, however, the following rule of thumb may be beneficial: should observed rates of development lag behind what is expected, unattributable to another impediment, intervention to aid the development of social capital may be beneficial. However, policy should be careful to realise that social capital is not a panacea. Interventions should aim to reduce transaction costs by aligning stakeholder objectives and building mutual understanding of what each participant requires for viable operation. A review of the literature finds the following interventions suitable for green innovation [66-68];

- Provision of incentives /information on the value of networks/consortia;
- Partnership programs;
- National-level fora and platforms for dialogue.

An 'Interactive learning' approach should be adopted, where possible, to adapt success from one context to another.[d]

Behavioural impediments

At the household level, there may be a negative bias towards new technology investment, even when adoption is cost-effective.[69-71] A review of the literature finds the following impediments: [7, 72, 73]

- A negative perception of the installation burden;
- A lack of familiarity with a new technology;
- Poor understanding of how the new technology can meet modern needs;

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[d] Interaction between Danish and Indian government officials, for instance led to the development of a successful Indian wind energy sector.[66]

- Sustainability may not be a salient priority for a householder with multiple commitments;
- Short-term (i.e. myopic) decision-making;
- Householders are otherwise unwilling to change. [7, 73]

Indeed, it may be rational for consumers to ignore environmental attributes if they have strong preferences for other product attributes, given the time investment required to acquire this knowledge.[74] Allcott and Mullainathan [75], Shafir [76] and Lunn [24] have reviewed the policy options available to counteract these and other behavioural bias. The following strategies emerge in the literature. First, salient and simple information can help guide good consumer choices.[24] If this is expected to be ineffective, bans, mandates or economic incentives may also guide sustainable behaviour.

If unsustainable choices persist, further action may be justified if: (a) there is an unmet target behaviour (e.g. adoption of hydrogen vehicles) and there is an identified behavioural bias influencing this;[e] or, (b) there is a behavioural bottleneck such as limits in self-control, attention, cognitive capacity, and understanding. The following options exist.

- Adjustment of choice architecture: Choice architecture refers to the way choices are presented.[f] Münscher, Vetter [77] provide a taxonomy with which policy may present choices to guide sustainable decisions.
- Strategic framing of options/nudging towards the sustainable option:[g] A regulator may frame choices such that the susainable option is most attractive. For instance, policy may frame benefits in the context of other attributes, such as health or environmental co-benefits [79, 80]; commitment devices, goal setting and strategic labelling [23].
- Establishment of sustainable norms: Policy can establish sustainable behaviour as the social norm. Prominent examples include professional home energy audits [81] and the use of social comparison-based home energy reports[61][h].
- Establish positive attitudes towards novel technologies: Low-carbon transport, for example, should evoke substitute symbolic meanings associated with ICE vehicle ownership.[26]

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[e] If people strongly oppose a behavior or are forced not to display it because of external factors, a choice architecture intervention does not appear suited.
[f] For example, policy may instruct firms or government agencies to strategically present information and choice sets such that sustainable behaviour is most salient or default option [69-71]; Many consumers have pro-environmental preferences, with few acting on this. A default nudge, for instance, can better align preferences with action[25].
[g] Nudges and framing may take many forms. Lunn [24] and Lehner, Mont [78] provide a review.
[h] However, Andor, Gerster [82] find evidence that this may be less cost-effective in a European context where air conditioning is less prevalent

- Dispersed seeding of early adopters: Peer effects influence adoption of a new technology, whereby middle and late adopters are often influenced by an interaction with an early adopter. Policy may leverage this dynamic by 'seeding' supports for adoption throughout various social strata[8, 83, 84].

Behavioural interventions must be carefully designed and researched, as they have potential to 'backfire'. For example, should financial incentives be offered, they should be targeted at those who would not otherwise adopt to avoid the crowding out of (generally higher) altruistic investment.[85] Bicchieri and Dimant [86] provide a review of potential risks.

Institutional, regulatory and political impediments.

At the firm level, institutional and regulatory barriers may limit adoption.[87] First, external financing is generally more expensive, and therefore investment is more difficult, during low periods of the business cycle.[88, 89] Additional support, in the form of access to credit or price supports, may be required during these periods. Second, policy must ensure that regulation is updated in a timely manner to facilitate potential new uses for existing resources and avoid creating an unnecessary additional impediment to deployment.[i]

Political ideology can influence technology adoption. Policy supporting green investments on environmental grounds should be careful to target those politically predisposed to environmental investment. Such a household is less likely to invest in energy efficiency, for instance, if the choice is framed to them as an environmental investment. This tends to hold even when the respondent might have otherwise made the investment.[27]

Successfully enacting a policy of support depends on political ability to balance stakeholder interests; policy options that run counter to pre-existing interests are difficult to implement. Policy must balance the interests of various industry, consumer, resource owner and non-governmental organisations. This has influenced the choice of policy instrument, signified by an EU policy landscape characterised by largely riskless remuneration schemes, high degrees of technology differentiation and decentralized decision-making. [28]

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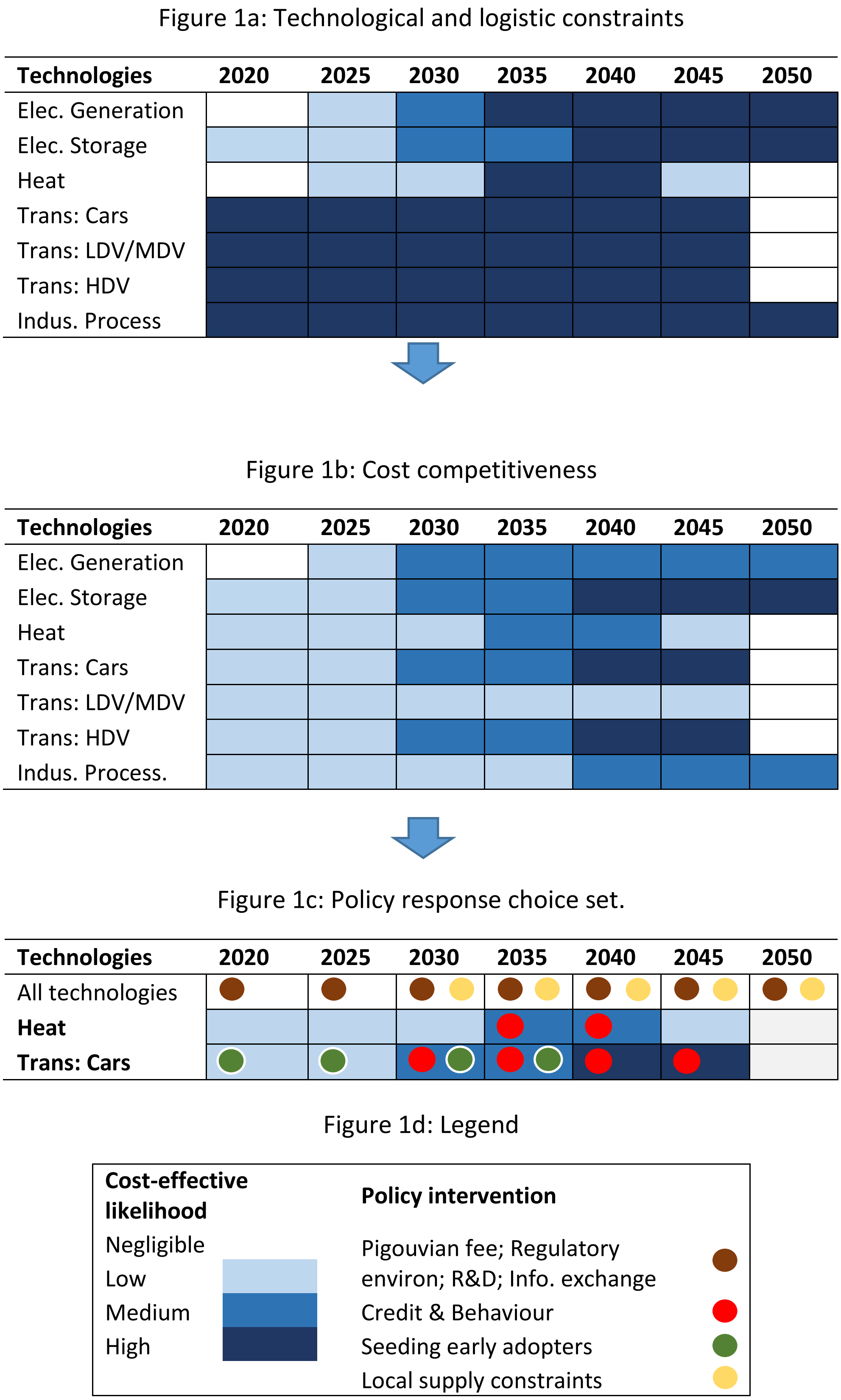
[i] This has been observed with respect to the deployment of offshore renewables[90] (foreshore licensing and leasing); the use of electric scooters in cities[91]; and the transport and use of hydrogen.[92]

Table 2: Decision-making process

Category	Constraint		Guideline
1: Establishing deployment			
1.a:Base			
	Technological & Logistic constraints	Lead-in	Earliest date of availability
		Countback:	Latest date of target-consistent deployment
1.b: Cost			
	Cost competitiveness	Certain costs	Traditional Cost-Benefit Analyses (e.g. HM Treasury [29])
		Uncertain costs	Precautionary principle; Table 1
2: Policy Decision			
2.a: Economic Science			
	Production Capacity		Incentivise capacity additions; lower transaction costs;
	Missing/imperfect markets	• R&D	Match public investment; Prizes, grants, etc.
		• Risk	Stimulate futures markets; price guarantees
		• Externalities	Pigouvian fee
		• Credit	Public provision of credit
		• Market concentration	Stimulate futures markets; incentivise consumer switching; regulation
		• Social capital	
2.b: Behavioural Science			
Consumer under-adoption of new technology		• Negative perceptions • Unfamiliarity • Poor understanding • Salience • Ignorant/ unwilling	• Choice architecture • Nudges and framing • Norms • Create positive attitude • Seed dispersed early adopters
2.c: Institutional/Regulatory/Political Issues			
• Stage of business cycle			Incorporate business cycle in policy design
• Regulatory environment			Timely policy review
• Political ideology			Incorporate ideology in support targeting
• Competing stakeholder interest			Consideration in instrument choice

Figure 1: Hydrogen deployment and policy intervention



3. Application: Deployment of Hydrogen technology

This section applies the decision framework to evaluate the policy response to 'green' hydrogen (i.e. hydrogen generated from the electrolysis of water using renewable-generated electricity). Figure 1 displays the decision process applied to this context; first the window of deployment is determined, followed by required policy interventions, considered relative to the deployment timescale.

3.1. Step 1: Technological and Logistical Constraints

Hydrogen emerges as a technology option under scenarios of high carbon abatement (such as those corresponding to targets of the Paris Agreement)[11, 13] and plays a more prominent role when technologies such as Carbon Capture and Storage (CCS) are unavailable[1, 11, 13] (see Appendix A for further detail). Following the precautionary principle, it is imprudent to assume either widespread CCS availability or unmet climate targets. Therefore, hydrogen is likely a required intervention. While many forms of hydrogen production are all proven and available, [93, 94] there are technological and logistical constraints that policy should consider.

Figure 1a charts the likely window of technological availability for each application, conditional on the technological and logistical constraints. The factors influencing availability are discussed in Box A.

3.2. Step 2: Cost competitiveness

Estimating the hydrogen cost trajectory involves; (i) calculating the cost of hydrogen-production and (ii) calculating the relative cost of hydrogen applications, conditional on expected hydrogen production costs. This analysis will maximise the expected value under various scenarios, following the first procedure outlined in Table 1.

3.2.1 Cost of Hydrogen Production

As Appendix B outlines, green hydrogen production costs are primarily driven by the cost of capital and electricity. Figure 2 illustrates the 2030 and 2040 expected Levelised Cost of Hydrogen (LCOH) as a function of electrolyser capital cost, the levelized cost of electricity and the expected capacity factor. Pessimistic, expected and optimistic technology development scenarios are assumed. By 2030, there is a high likelihood of LCOH values of less than \$6/kg, a good likelihood of LCOH values of \$4/kg or less and a reasonable likelihood of LCOH values of \$2/kg or less.

By 2040, there is a high likelihood of LCOH values less than \$4/kg, a good likelihood of LCOH values of \$2/kg or less and a reasonable likelihood of LCOH values of \$1/kg or less. Achieving an LCOH of \$1/kg or less requires the levelized cost of electricity to fall below US\$10/MWh and electrolyser capacity factors close to 50% or above be achieved.

Box A: Factors influencing Technological and Logistical Constraints

The lead-in time required to develop a hydrogen distribution network may constrain rollout for transport and heat applications. For transport, Staffell, Scamman [1] find that early-stage infrastructural requirements are relatively low. They find that as few as 60 small refuelling stations with onsite hydrogen production would be sufficient to supply most of the UK population in the early stages of a transition to fuel cell vehicles, with additional infrastructure deployed as demand increased.[1, 95] Should hydrogen vehicles emerge as a cost-competitive solution, for freight especially, gradual conversion of infrastructure will likely not be a factor prohibiting deployment. This, coupled with the fact that hydrogen vehicles already exist, leads one to conclude that technological constraints are unlikely to impede deployment.

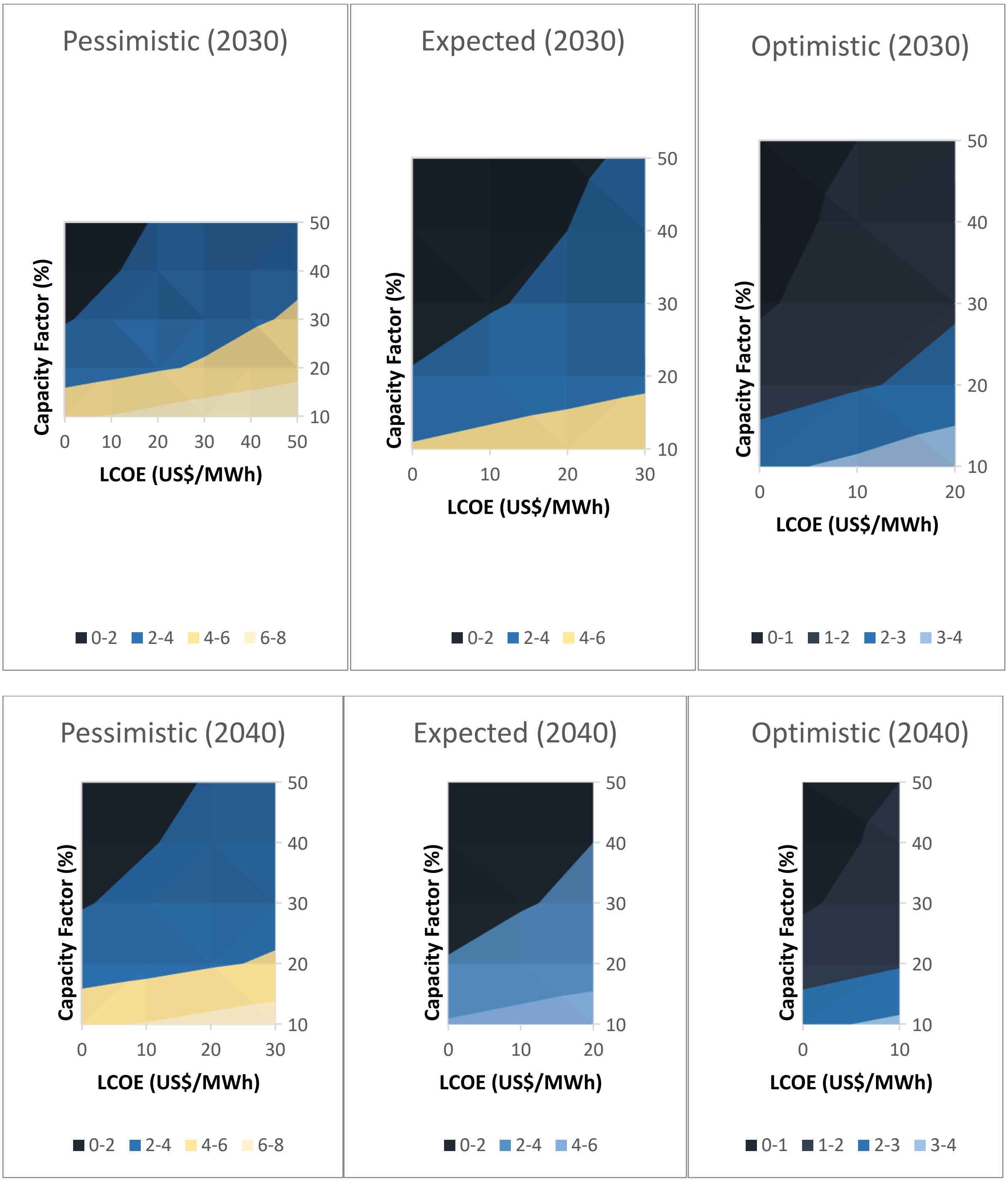
A facet of some, but not all, high-penetration scenarios incorporates the use of hydrogen for heating which would require investment in either network infrastructure or heating technology. This may require a considerable lead-in time, representing upper/lower bound logistical constraints. The time required for conversion is uncertain, but a comparable technological switch occurred when many countries switched from town gas to natural gas. The UK, for instance, replaced 40 million appliances over an 11-year conversion programme.[96] If a similar pace of installation were observed for hydrogen conversion, full conversion is unlikely to happen before 2030 (if initiated in 2020). Furthermore, to achieve decarbonisation by 2050, installation must be initiated by c.2040.

Hydrogen may be used as a fuel in existing fossil fuel turbines and for electricity storage. Turbine manufacturers such as GE and Siemens are already developing gas turbine equipment that can operate on 100% hydrogen, with the HYFLEXPOWER demonstration project expected to be running by c.2023, providing a lower bound on potential availability.[97] However, this is the timescale for an initial prototype development, with a low likelihood therefore assumed for the following time periods.

For electricity storage, hydrogen becomes cost-competitive when discharge durations beyond 20–45 hours are considered.[98] The research of Albertus, Manser [99] suggests that such storage requirements may be first required when the electricity system approaches 80% renewable penetration. For many systems, such degrees of renewables penetration will occur post-2030, likely c.2040.[100, 101]

Alongside these applications, technologies exist for hydrogen-based industrial processes, with research finding economic, rather than technological constraints, influencing adoption.[35, 102-104]

Figure 2: 2030 LCOH (USD/kg) conditional on capacity factor and LCOE



Notes: Data source Aurora Energy Research [2], The Hydrogen Council [103], Hydrogen Council [105]. The cost-reduction trajectory is described in Appendix B whereby the likely LCOH values at a given milestone on the path to 2050 is estimated conditional on expected capital cost and electricity price changes. A pessimistic scenario corresponds to a slower rate of capital cost reduction, in the range of 5-18%. An 'expected' scenario corresponds to one of median expected capital cost reduction, with a learning rate of 18%. An optimistic scenario corresponds to one of high expected capital cost reduction, with a learning rate in the range of 18- 31%.

3.2.2 Cost of Hydrogen Application

There are four primary applications for hydrogen technology; space heating; transport; electricity (generation and storage) and use in industrial processes. Appendix B outlines this analysis in full, with a synopsis provided below. Figure 1b updates the window of technological availability to account for cost-effective deployment.

Space Heating

Hydrogen-sourced heating technologies are in the early stages of development. Cost projections are therefore speculative. Estimates suggest cost competitiveness with electric heat pumps occurs at a cost of c.US$2/kg in Western Europe and US$1-2/kg in the US, China and Canada.[98] According to the estimated production cost trajectory, this is likely achievable by 2040. It may be achievable by 2030 if electricity has an LCOE of US$20/MWh or less and electrolyser deployment continues as expected. Given the likely lead-in time (see Section 3.1), initiating deployment post-2045 is likely too late to achieve decarbonisation by 2050.

Transport

The extent with which hydrogen-based transport vehicles will be deployed is predicated on the cost relative to electric or biomass-powered alternatives. For passenger cars, fuel cell electric vehicles currently have higher capital and operating costs than Battery Electric Vehicles (BEVs) but could eventually become a cheaper alternative (at c. US$2/kg [106]), depending on the future cost trajectory.[1, 107, 108] There is a medium-low possibility that hydrogen will be available at a production cost of US$2/kg or less in 2030, with a medium-high possibility post-2040 (See Figure 2).

Medium/Heavy Duty Vehicles (MDV/HDV) comprise categories such as buses and trucks. These vehicles require higher energy densities to haul heavy goods, positioning hydrogen as a more suitable fuel than electricity.[22, 109-111] McKinsey and Co. [106] find that hydrogen for freight transport becomes cost competitive with other low carbon alternatives at an LCOH value of about US$3/kg. There is a medium-low likelihood of achieving a levelized cost of hydrogen production of US$3/kg or less before 2030 (See Figure 2). There is a greater likelihood of this being achieved post-2030, primarily driven by reductions in the levelized cost of electricity.

Given current information, hydrogen is not a likely energy carrier for light duty vehicles such as small vans and minibuses. Jones *et al.* [145] compare the total cost of ownership for various brands of light-duty vehicles, finding that hydrogen models struggle to break even with electric alternatives under a wide range of cost assumptions. Breakeven may occur if there is a considerable reduction in the capital cost of these vehicles relative to non-hydrogen alternatives.

Electricity

As Section 3.1 discussed, the requirement for hydrogen-based electricity storage is predicated on technological constraints likely to transpire in the 2030-2040 timeframe. This is the primary determinant of deployment. Alternatively, hydrogen can be blended with natural gas (‘power-to-gas’; P2G). Current estimates predict costs far in excess of that which would be deemed cost-effective.[112, 113] However, P2G enhances the value of the generation portfolio for certain renewable generators.[114]

Hydrogen may also be used as a fuel in existing fossil fuel turbines. Currently at a pre-commercial stage of deployment (see Section 3.1), a low-medium likelihood is assumed to reflect this pre-commercial stage of development.

Industrial processes

Hydrogen can be used for ammonia production (the majority of which is used as a feedstock for fertiliser), methanol production and as a substitute for fossil fuels in steel production. Viable ammonia production requires a high carbon price (US$200/t$CO_2$) and low LCOH (c.US$3/kg). This will occur by 2030 with a low-medium likelihood and by 2040 with a high likelihood. Viable methanol production is competitive against grey hydrogen at costs of US$0.80-1.50/kg, with carbon pricing having limited effect.[98] This is likely to transpire post-2040 and close to 2050 on the decarbonisation trajectory.

Hydrogen-based steel production requires hydrogen costs of US$1.80-2.30/kg to become cost competitive in the US, with a higher break-even point in regions with more expensive coking coal, such as Europe or Japan.[98] Competitiveness against conventional blast furnaces will largely depend on the cost of carbon. With an LCOH of US$2.30/kg, hydrogen-based steel production can outcompete blast furnaces with CO_2 costs of less than US$100/t$CO_2$. Hydrogen for steel production therefore requires an optimistic deployment and cost reduction schedule to be cost competitive by 2030, with a more likely trajectory achieving cost competitiveness by 2040.

3.3. Step 3: Policy implications

In many cases, market forces will drive deployment, subject to the suitable regulatory environment with minimal transaction costs being in place. This is particularly true for applications to electricity storage/generation, industrial processes and heavy duty vehicles. Facilitating this regulatory and competitive environment is not time-dependent and can be established immediately, as represented in Figure 1c. For heat and transport, there are a number of time-dependent interventions (i.e. those that are most effective during, or just prior to, adoption) which relate to heat and transport-related deployment. These are highlighted in Figure 1c. Each intervention will now be discussed in greater detail.

3.3.1 Cost competitiveness

Technology ‘makers’ can influence the cost trajectory of hydrogen technology and therefore this is an endogenous variable in the policy decision process. As the Appendix shows, even with low rates of capital cost reduction (i.e. ‘learning’), a competitive production cost may be achieved with reasonable certainty. There are two important policy lessons for technology makers.

First, cost competitiveness is conditional on increasing the number of deployed electrolysers by a factor of 1,000 by 2040.[2] While this is expected,[2] policy should immediately focus on lowering the barriers to this deployment between now and 2030. This may involve ensuring that appropriate regulatory conditions and adequate social capital is in place. Pertinent factors include ensuring;

- a suitable regulatory environment is in place;
- credit is available to overcome any capital constraints
- there are no impediments to information exchange between stakeholders. Deployment may be accelerated through the establishment of stakeholder groups, information exchange platforms, etc.

It is important to note that learning investments are more important than lab-based R&D for technology makers. Hydrogen production is more likely to benefit from deployment-related learning investments. Public innovation investments should be more closely aligned with deployment-related subsidies as opposed to lab-based subsidies.[34]

Many of the areas for which cost reductions may be achieved are associated with production process standardisation and economies of scale. The operation of pilot plant is key to gain operational experience and optimise system design. Laboratory research is not without benefits and should be focused on reducing the operating temperature for SOECs and developing new system designs such as PEM stacks for higher pressure or differential pressure operation (important for direct integration with a renewable supply).

3.3.2 Economic, Behavioural, Institutional/Regulatory/Political impediments

Economic, behavioural, institutional, political and regulatory impediments are endogenous to the decision-making process for both technology takers and technology makers. Relevant issues will now be discussed.

Local production capacity may pose a deployment constraint

Global production bottlenecks are unlikely to be a pressing policy concern.[2] This does not rule out the possibility of local bottlenecks, especially as production is likely to be geographically concentrated. In the short term, this will lead to economic rents being accrued to producers at the expense of consumers and/or public funding bodies. In the long term, this should give the required signal to expand capacity. Interfering with short-run economic rents is second best policy as it may run the risk of dampening the longer-term capacity investment incentive. The first best outcome is to avoid this capacity constraint.

Policy should anticipate any local bottlenecks, putting in place measures to tackle the source of any identified constraint (e.g. production incentives, removal of barriers to transport/entry; impediments discussed below). This is especially important should a demand stimulus be put in place.

There may be scope for policy to ensure the required social capital is in place. This may be in fields such as to establish business connections and to develop an understanding of hydrogen-based production methods to facilitate adoption in a timely manner.

Policy must correct incomplete markets for emissions and risk

The adoption of hydrogen as part of a decarbonised portfolio of technologies should be guided by technology-neutral policy targeted at specific market failures. To guide emissions reduction, the first-best solution is a target-consistent high and rising carbon price.[3]

There may also be incomplete markets for risk, especially in relation to electricity storage and generation. At best, this may slow down investment. At worst, this may lead to underachievement of policy targets. There is a social value to timely investment and therefore an economic rationale exists to correct for this market failure. This may include investment products and/or price supports that hedge some of the risk associated with electrolyser investment. However, there is a social value to exposing investment to some risk, such that investment in the efficient portfolio of technologies is incentivised. Methods exist to efficiently design such price supports [4, 5].

Investment incentives may be stronger in some markets than others. Liberalised electricity markets tend to have strong incentives and often bespoke markets for investment in generation/storage capacity. Longer-term storage forms part of the contracted capacity as intermittency grows as a proportion of total generation. This should be technology-neutral.

Similarly, adoption of hydrogen-fuelled vehicles should be guided by preferences and prices, technology-specific policy should not distort this decision. While hydrogen is the frontrunner to serve decarbonised HDVs, the relative balance of hydrogen and non-hydrogen LDV and private cars is unknown. The relative balance between electric and hydrogen-fuelled vehicles should be determined by consumer preferences in this instance (see Appendix for full discussion).

Institutional constraints may impede the first-best solutions discussed above. If competing stakeholder interests do not allow for a target-consistent carbon price trajectory, subsidies or price supports are likely preferable to under-investment in decarbonisation.

Firm and household level access to credit may impede timely investment

Investment in dwelling heating/insulation and transport technologies may be hampered by credit constraints. Low-cost loan or pay-as-you-save schemes should form at least part of any deployment incentive. Supports should be technology-neutral if multiple technologies may serve a given requirement.

Behavioural biases may impede adoption of transport and heating technologies

Transport and heating technologies are predicated on individual and household-level adoption. The literature has shown that inattention, negative perceptions and unfamiliarity with how they may meet modern heating needs are among the most prominent biases impeding adoption.[6] As section 3 outlines, and the report of Williams, Lohmann [6] alludes to, information campaigns may be a suitable first point to address this issue, followed by the measures identified in Section 3. Hydrogen-based transport may be subject to fewer behavioural impediments relative to electric vehicles as they do not incur many of the negative traits such as range anxiety, etc.

As discussed in Section 3, any environment-centred information campaign should be targeted towards those who are positively pre-disposed to environmental policy and who would invest through environmental altruism. An alternative framing should be adopted for those politically averse to environmental policy.

Distributed seeding of early adopters

Should price supports be offered for heating or transport technologies, 'seeding' such support throughout various social strata, rather than concentrating adoption among a single cohort, may leverage more positive peer effects and lead to greater adoption[7, 8].

4. Conclusion: Structured decision-making going forward.

Achieving many sustainable development goals requires new and uncertain technologies with policy intervention required in many instances. Policymakers and regulators are struggling with designing the appropriate response as guidance is scattered across many disparate academic fields. This perspective has presented a method to join disparate strands of literature to synthesize a single, tractable framework to clarify the decision. While applied to hydrogen technology, the decision framework is general and may be applied to any sustainable technology intervention that may require public support. With a requirement for unprecedented rate of technological change as climate and ecological constraints become ever more binding, a structured method for policy intervention will grow with importance.

Appendix A: Hydrogen technology trajectory

Energy systems models have identified the potential future roles that hydrogen may serve in a least cost portfolio. Hanley, Deane [11] review this literature, finding that hydrogen is likely required for electricity storage[115-117] (particularly inter-seasonal electricity storage); heating[102, 104, 108][j]; transport[102, 110, 121, 122][k] (particularly medium and heavy-duty vehicles); heavy industrial processes[123]; and as a zero-carbon feedstock in chemicals and fuel production.[124]

Hydrogen features more prominently when either (1) there is a high carbon abatement scenario (e.g. an EU target of at least 85% decarbonisation)[11, 13] or (2) many substitute technologies are unavailable. The manifestation of this varies by application. For transport, the decarbonisation of Medium and Light-Duty Vehicles (MDVs and LDVs, respectively) occurs under a high decarbonisation scenario[13]. Countries with abundant biomass, such as Brazil, are less likely to require hydrogen technologies for transport.[11] However, this does not rule out the use of hydrogen, as biomass with CCS can enable the use of hydrogen as an energy carrier in these scenarios.[11, 13, 125, 126]

Hydrogen has enhanced importance in the absence of Carbon Capture and Storage (CCS).[1, 11, 13] This is because there is a greater proportion of intermittent renewables and a greater requirement for technologies to shift electricity availability [11, 13]. This requirement may grow further if electricity market interconnection is limited.

Infrastructural availability is an important determinant of both achieving cost competitiveness (through learning by doing) and ensuring deployment once competitiveness has been achieved. Many development pathways exist for hydrogen infrastructure, such as systems centred around local production or a centralised production (and distribution) network. [1] However, while the economies of scale associated with a networked service may lead one to believe that infrastructure requirements are prohibitively large, this barrier is often overstated. Staffell, Scamman [1] finds that as few as 60 small refuelling stations with onsite hydrogen production would be sufficient to supply most of the UK population in the early stages of a transition to fuel cell vehicles, with additional infrastructure deployed as demand increased.[1, 95] Should hydrogen vehicles emerge as a cost-competitive solution, for freight especially, the gradual conversion of infrastructure in this way would be less prohibitive than some may have suggested.

A facet of some, but not all, high-penetration scenarios incorporates the use of hydrogen for heating. Hydrogen may be blended with methane or natural gas for use in existing gas networks without investment in the network, or a 100% blend may be facilitated with capital

[j] Hydrogen can be transmitted through existing gas infrastructure, opening up the possibility to use hydrogen for heating. [118-120]

[k] Hydrogen is an energy dense carrier. This is a desirable property for applications that require considerable power such as freight, shipping and aviation[121]

investment. The UK TIMES surveyed a scenario whereby gas pipes were converted to polyethylene pipes to facilitate a 40% penetration in home heating. Should a high concentration hydrogen power-to-gas deployment scenario be envisaged, infrastructural availability and conversion must be anticipated. This would vary depending on the envisaged scenario. If distributed to local heat networks, then localised infrastructure would be required. If distributed to dwellings where on-site hydrogen boilers convert the fuel to heat, then upgrading of the capital stock would be required. This is a considerable investment, but is not unprecedented. For instance, many countries have switched from town gas to natural gas in recent decades, with the UK replacing 40 million appliances over an 11-year conversion programme. Adjusted for inflation, this was the equivalent to £8bn in 2015.

A.1 Hydrogen production

To understand the potential cost of hydrogen, one must first review the potential production methods. Hydrogen may be generated using a range of methods and energy sources. Currently, 96% of hydrogen is created directly from fossil fuels ('Brown', 'Black' or 'Grey' Hydrogen) with the remainder created through the electrolysis of water.[11] To be low-carbon, electricity generated by burning fossil fuels must either be combined with Carbon Capture and Storage (CCS) ('Blue' Hydrogen) or generated using renewable-generated electricity ('Green' Hydrogen).[l]

A number of policies envisage the short to medium-term use of 'blue' hydrogen, with a long-term objective of using green hydrogen exclusively.[13, 94, 127] While it is possible that blue hydrogen may be low-carbon, emerging research advises caution against using this as a bridging strategy. Longden, Beck [127] find that a short-term focus on blue hydrogen, as many national strategies foresee, may be incompatible with long-term decarbonisation objectives and raise the risk of stranded assets. This is stated for two reasons. First, the emissions from gas or coal-based hydrogen production systems could be substantial, even with CCS. Second, there is evidence to suggest that the cost of CCS is higher than often assumed, while electrolysis with renewable energy could become cheaper in the long-term. [127] As such, the remainder of this paper will focus on green hydrogen.

Green hydrogen may be created using Alkaline (AEC), Proton Exchange Membrane (PEM) and Solid Oxide (SOEC) Electrolysis Cell techniques. Alkaline Electrolysis Cell (AEC) technology is the incumbent and, as such, is readily available. AEC technology has relatively low capital cost as it does not use noble metals and has relatively mature components, unlike PEM and SOEC alternatives.[34] The scope for further cost reduction is potentially limited however, due to low current density and operating pressure. [34, 128, 129]

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[l] There are further emerging technologies, such as water-splitting processes powered by solar energy and 'pink' hydrogen, which is produced through nuclear-generated electricity.

Proton Exchange Membrane (PEM) electrolysis cell systems are less mature but provide greater scope for future cost reduction, due to a high power density and cell efficiency. [34, 129, 130] PEM electrolysis also has a more flexible operation profile. It does, however, use more expensive raw materials and current technology has a shorter operation lifecycle. Research and development efforts are therefore targeted towards reducing system complexity to enable system scale-up and reducing capital costs through less expensive materials and more sophisticated manufacturing processes. [34, 129, 130]

Solid Oxide Electrolysis Cell (SOEC) is the least developed electrolysis technology and has not yet been widely commercialised. Potential advantages include high electrical efficiency and low material cost. However, the SOEC process suffers from high materials degradation and therefore lifecycle costs are relatively high. This is the primary impediment to commercialisation.[1, 34]

Despite greater expense in the short to medium term, PEM and SOEC technologies have the greatest long-term potential. This is particularly true for direct coupling with renewable installations; PEM and SOEC technologies better complement intermittent renewables.[34][m]

[m] Both PEM and SOEC operate better in varying dynamic range, while can also operate in a low dynamic range without affecting gas purity[34]

Appendix B: Estimating Hydrogen's Cost Trajectory

Green hydrogen cost competitiveness is driven largely by electrolyser capital costs and the cost of electricity. Policy should focus on these drivers of total cost when considering cost competitiveness with alternative technologies. [34, 35, 127, 131] Efficiency improvements in operating/production costs are a relatively small, and likely insignificant, determinant of cost competitiveness. [34, 35, 127, 131] Deployment-related cost reductions are a stronger driver of cost competitiveness than lab-based R&D. This review will therefore focus on capital and electricity costs to estimate expected levelized costs of hydrogen, with deployment-related 'learning' driving cost reductions.

B.1 Capital cost of hydrogen

Estimates vary with regard to the capital cost of hydrogen electrolysers. Current point estimates place the capital cost of hydrogen electrolysis at around €1000/kW for AEC and €2000/kW for PEM electrolysers.[34] The capital cost for SOEC technology is expected to exceed €2000/kW.[34] With a closer examination of the literature, c.2020 capital costs fall in the range of c.$500-$1,800/kW[n], with a number of low (€400/kw) and high (US$2,497/kW[127]) outliers. The reported lower bound (and outlier with respect to the distribution of potential capital costs) has been projected by 'Nel Hydrogen', a dedicated hydrogen production company. They find CAPEX values as low as €400/kW for alkaline systems when scaled to 100 MW electrolyser units. This estimate is based on an intelligent engineering design of a 40 stack system.[133]

B.1.1 Expected drivers of capital cost reduction

Capital cost reductions of greatest importance emanate from (1) the scaling of plant capacities (e.g. from 1MW to 100MW); (2) a greater proportion of time with which the electrolyser is being utilised; and (3) economies of scale in the production of electrolyser units, alongside related benefits such as product standardisation.[34] These factors have been consistently identified as drivers of cost reduction in the literature.[34, 35, 127, 131]

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[n] The International Energy Agency [98] report that the 2019 capital cost of Alkaline (AEC) and Polymer electrolyte membrane (PEM) electrolysers is between US$500-1400/kW and US$1100-1800/kW, respectively[127], projected to fall to $400-850/kW and $650-1500/kW by 2030, respectively. Longden, Beck [127] provide a comprehensive summary of capital cost data, finding cost values ranging from US$500/kW to US$1,000/kW (with an outlier of US$2,497/kW), with future cost values ranging from US$200/kW to US$1000/kW. Götz, Lefebvre [132] review academic and industry sources, finding that costs range from US$700-1,050/kW for AE and US$1,200-1,500/kW for single-stack PEM electrolysers. Through expert elicitation, Schmidt, Gambhir [34] find that capital costs for AEC systems by 2020 at current R&D funding and without production scale-up lie between €800-1300/kW (all 50th percentile estimates), but could range from €700- 1400/kW (10^{th} – 90^{th}). For PEM, the respective range is 1000–1950 € kW_{el}^{-1} (all 50th) and 800–2200 € kW_{el}^{-1} (lowest 10th, highest 90th). SOEC electrolysers have the most expensive estimates at €3000–5000/kW (all 50th) with a significantly higher uncertainty range of €2500–8000/kW (lowest 10th, highest 90th)

Efficiency improvements in operating/production costs are a relatively small, and likely insignificant, determinant of cost competitiveness. [34, 35, 127, 131]

Scaling of plant capacity takes the form of multi cell structures. From an economic perspective, this leads to improved hydrogen conversion efficiency and is important for the competitiveness of SOEC and PEM technology, especially. To illustrate, in a test of SOEC conversion, 1-cell, 2-cell and 30-cell stacks obtained steam conversion rates of 12.4%, 23% and 82.2%, respectively, and system efficiencies of 16.1%, 27.2% and 52.7%, respectively.[134] Related to this, further expected technological developments in this regard include improved system lifetimes (particularly important for PEM and SOEC technologies).

Aurora Energy Research expect that by 2025, a typical electrolyser project will be 100-500 MW in size and will typically supply 'local clusters', meaning that the hydrogen will be consumed locally to the facility. By 2030, typical projects are expected to scale up further to 1 GW+, with the emergence of large-scale hydrogen export projects, deployed in countries benefiting from cheap electricity.[2]

Process intensification and the duration of time with which the capacity is in operation is similarly important.[135] This is clearly illustrated in an example given by Longden, Beck [127], who state that a reduction in the utilization rate from 80% to 20%, for a specific scenario, could result in the final cost of hydrogen increasing by around 50%, from US$4/kg to US$6/kg.

Stand-alone renewable and electrolysis systems may find it difficult to achieve cost competitiveness without high utilization rates/ firm grid backup. An electrolyser run from stand-alone renewable energy sources backed up with deep storage, or using the grid as backup, will be able to be run at high capacity rates, possibly exceeding 90%.[1, 13, 34, 127, 131, 133, 136] This would require that the electricity from the grid is primarily renewable for the hydrogen to be considered 'green'. An electrolyser run directly from a wind farm could operate at capacity factors close to 45%, and a standalone solar farm at c.30%.[34, 127]

Current cost projections are driven by modelled projections or expert elicitation.[133] Both sources will now be reviewed.

B.1.2 Expert elicitation

It is expected that PEM and SOEC will eventually surpass AEC to become the dominant hydrogen technologies, with much of the literature quantifying future costs through expert electicitation. Schmidt, Gambhir [34] carry out a comprehensive survey while Longden, Beck [127] review the published literature to provide these estimates.

Through expert elicitation, Schmidt, Gambhir [34] find an expected 2030 range of €750/kW, €850–1650/kW and €1,050-4,250/kW for AEC, PEM and SOEC electrolyser technologies, respectively. Such estimates assume that current levels of R&D and production scaling remain constant.[o] Other studies find similar expected cost values. The International Energy Agency [98] for instance, project that AEC and PEM-produced hydrogen will fall to $400-850/kW and $650-1500/kW, respectively.

Production scaling is more important than R&D investment to lower capital costs.[34] Schmidt, Gambhir [34] find that increased R&D funding alone can reduce capital costs by 0-24%, while production scale-up alone can reduce costs by 23-27% by 2030. Production scale-up is the most significant driver for SOEC technology as it is at a pre-commercial stage of deployment. There are expected diminishing marginal returns associated with production scaling; a doubling of R&D funding in the absence of production scale-up leads to 6–8% cost reduction, while a tenfold increase has an impact of 7–24% across all technologies.

R&D alone, without production scaling, is associated with lesser cost reductions. This is expected to yield 2030 capital costs in the region of €800/kW for AEC, with further reductions to €600/kW if coupled with R&D. Increasing the rate of R&D funding is expected to have a limited impact on AEC cost. Doubling R&D, in the absence of deployment scale up, reduces costs of PEM technology by 8% to c. €1,000/kW by 2030, and a 10-fold increase would decrease costs to €800/kW by 2030 (much less than the cost reductions associated with production scale-up). Coupling this with production scale-up further reduces costs to c. €800/kW and c.€700/kW, in the respective R&D scenarios.

For SOEC technology, doubling R&D, in the absence of deployment scale up, reduces costs by 8% to just under €3,000/kW by 2030, and a 10-fold increase would decrease costs to c. €2,500/kW by 2030. Coupling this with production scale-up further reduces costs to €2,500 with current and double R&D levels, and closer to €2,000/kW with ten times the R&D levels. For SOEC technology, production scale up is of paramount importance, second to R&D.

B.1.3 Experience curve

Alternative to expert elicitation, one may project the future cost of hydrogen using an experience curve. Experience curves depict the development of cost as a function of cumulative production.[116, 137][p] Experience curves are an empirical observation incorporating all cost factors, not just technological developments. In many applications (including those for hydrogen electrolysis), experience curves have been expressed as a power-law function:

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[o] These ranges summarise the expected (i.e. median) cost projection among surveyed experts. Schmidt, Gambhir [34] also consider the likely 10th-90th range to capture the full degree of uncertainty surrounding envisaged costs. When considering 10th-90th percentile cost ranges, Schmidt, Gambhir [34] find an expected 2030 range of €700–€1000/kW, €700–1,980/kW and €750-6,800/kW for alkaline, PEM and SOEC respectively, if current levels of R&D stay constant and with current degrees of production scaling

[p] Experience curves do not consider the factors causing cost reduction but rather are a method to predict future costs, conditional on cumulative installation. They exploit the observation that cumulative production is often the best- predictor of technology cost[131],[p].

$$c_t = c_0 \left(\frac{P_t}{P_0}\right)^{-\alpha}$$

Where c_t is the cost of the technology under consideration at time t, c_0 in principle the cost per item; P_t the cumulated production at time t, P_0 the number of items in the first batch of production, and α is the learning index or rate of cost reduction with every doubling of capacity.[131] The rate of cost reduction is subject to uncertainty. This uncertainty is particularly relevant in the context of electrolyser capital cost as the technology is relatively novel.

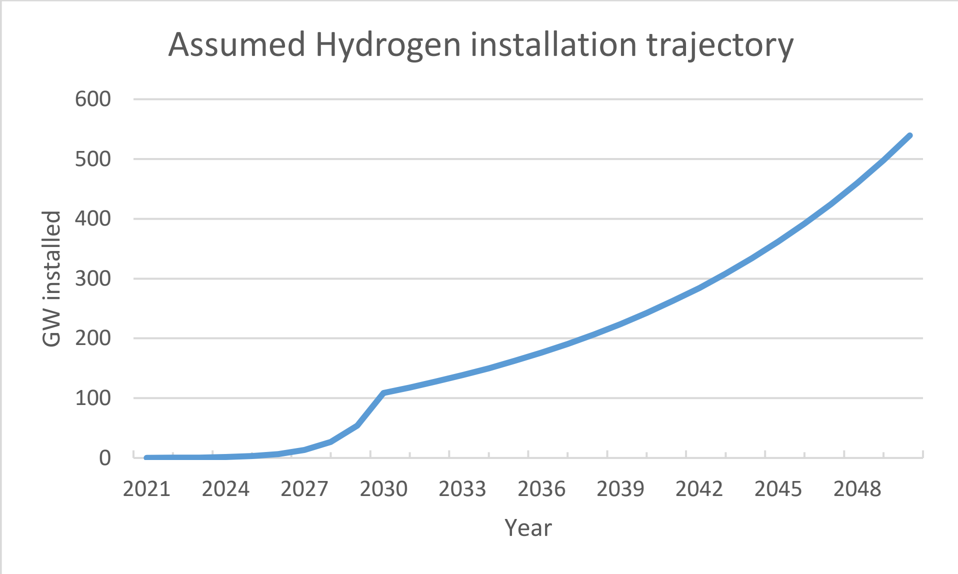
Taibi, Blanco [138] review rates of cost reduction, finding a median expected rate of cost reduction of 15-18%, ranging from 9% to 31%. Schoots, Ferioli [131], in a 2008 study of 1940-2007 data, find an expected learning rate of 18%+/-13% for electrolyser capital costs. The Hydrogen Council provide an alternative estimate, finding a rate of cost reduction of 13% for PEM electrolysis and 9% for AE electrolysis.[105] This is closer to observed ranges of cost reduction associated with wind, passenger fuel cell (17%) and commercial fuel cell vehicles (11%), while the 18% point estimate of Schoots, Ferioli [131] is closer to the rate of cost reduction associated with rapidly developing technologies such as solar (20%).[116, 139] A rate of cost reduction in excess of the upper bound of the quoted range (c.31%) has not been observed for any renewable technology.[116, 139]

B.1.4 Calculating expected hydrogen electrolyser cost

Expected electrolyser capital costs are modelled as a function of cumulative installation. To succinctly capture a wide range of possible eventualities, the following scenario is assumed. First, we follow the trajectory assumed by the Hydrogen council who assume, for green hydrogen, that there will be 90GW global deployment by 2030.[103] The 2040 deployment trajectory is calibrated according to that assumed by Aurora Energy Research [2] who have collated a global electrolyser database in May 2021, finding that, from a 2021 baseline of 0.2GW installed capacity, projects totalling 213.5 GW are planned for delivery by 2040. The implied 2030-2040 rate of annual deployment is assumed to continue post-2040. Within the 2021-2030 and 2031-2040 milestones, the rate of growth is assumed to be exponential, calibrated to the respective milestones. This accounts for the likelihood that the rate of deployment will be non-linear and bunched around 10-year milestones. Figure 3 shows this deployment trajectory.

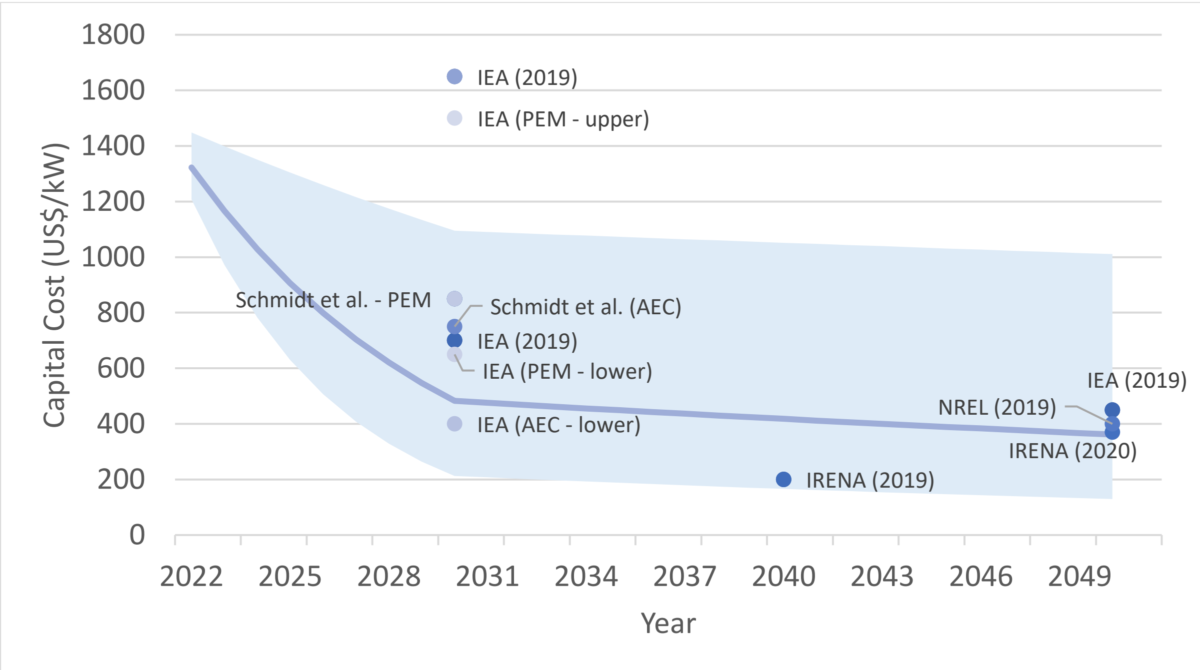
The implications that this deployment may have for cost given the range of expected cost reductions (learning rate of 18% +/- 13%) is shown in Figure 4. Figure 4 shows that expert views are well-aligned with an experience curve centred around 18%, assuming that the large scale deployment as surveyed by Aurora Energy Research [2] comes to fruition.

Figure 3: Expected hydrogen deployment trajectory



Note: Figure shows expected deployment trajectory calibrated to 100GW by 2030 and 220 GW by 2040, with the 2030-2040 rate of growth assumed for the 2040-2050 period. Deployment within each period is assumed to grow exponentially and follow a global rate of installation calibrated to that expected by the The Hydrogen Council [103] in 2030 and Aurora Energy Research [2] in 2040.

Figure 4: Expected hydrogen cost trajectory



Note: Figure shows expected cost trajectory with 18% rate of learning +/1 13%. Markers show cost values obtained from literature. The deployment trajectory is calibrated to 100GW by 2030 and 220 GW by 2040, with the 2030-2040 rate of growth assumed for the 2040-2050 period. Deployment within each period is assumed to grow exponentially and follow a global rate of installation calibrated to that expected by the The Hydrogen Council [103] in 2030 and Aurora Energy Research [2] in 2040.

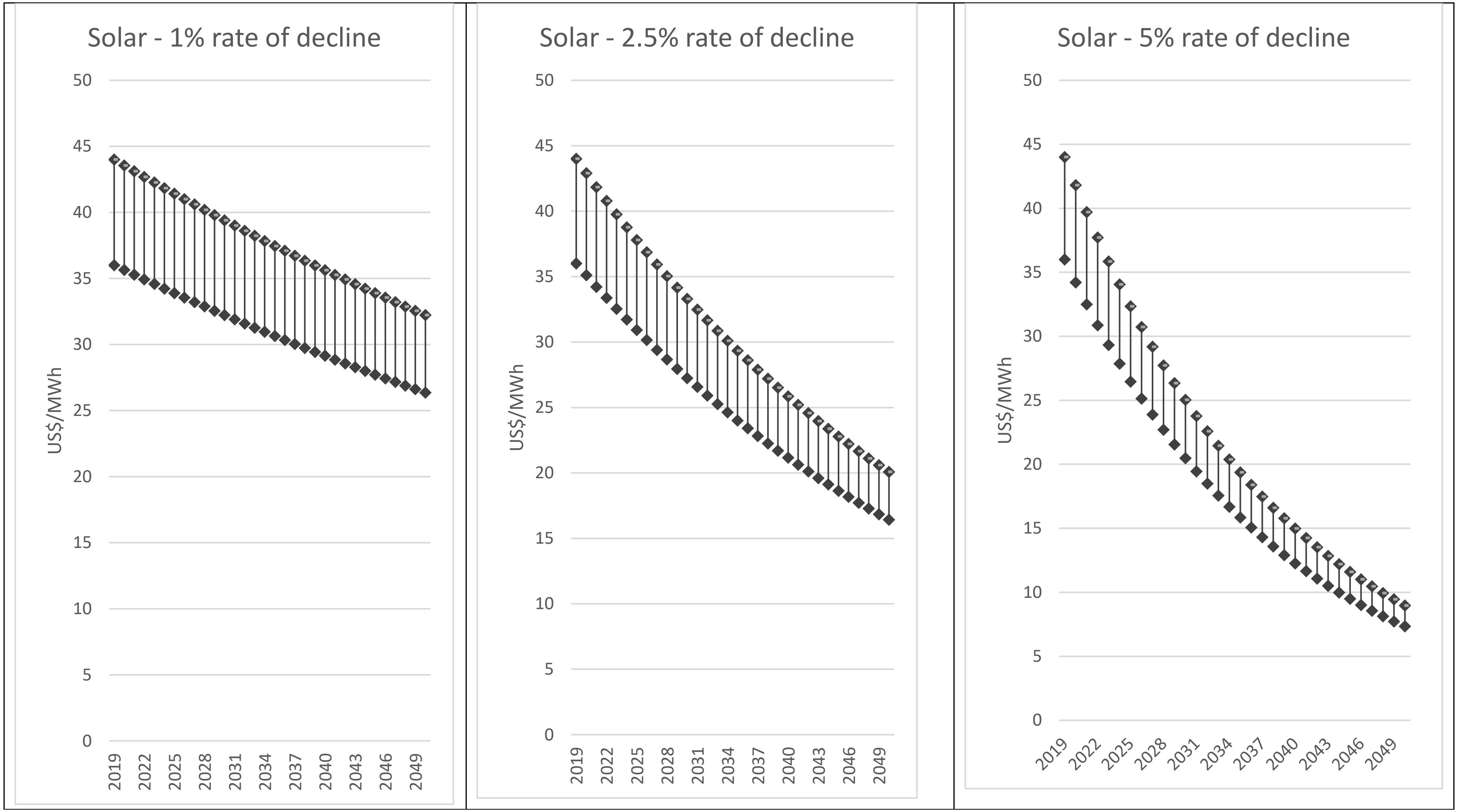
B.6 Electricity price

The second primary determinant of hydrogen cost is the cost of electricity used for electrolysis. This varies with the electricity source. For grid-coupled hydrogen, wholesale electricity costs vary according to the portfolio of technologies, demand profile and time of demand, among other factors particular to a given market. Prices vary widely, often going negative during periods when there is excess renewable generation and extremely high when there is a shortage. Monthly averages vary from c.€15/MWh to c.€80/MWh in many European regions.[140]

The cost of electrolysis directly coupled with a renewable installation will be determined by the levelised cost of electricity from the renewable source chosen. Lazard [141] finds that the levelised cost of electricity from wind and solar has fallen by an average of 5% and 11% per year for the past 5 years. Zhou and Gu [142] predict that compared with 2016, the investment cost of wind power will decrease by 19.6–30.8% by 2025 and 26.5–41.4% by 2030.

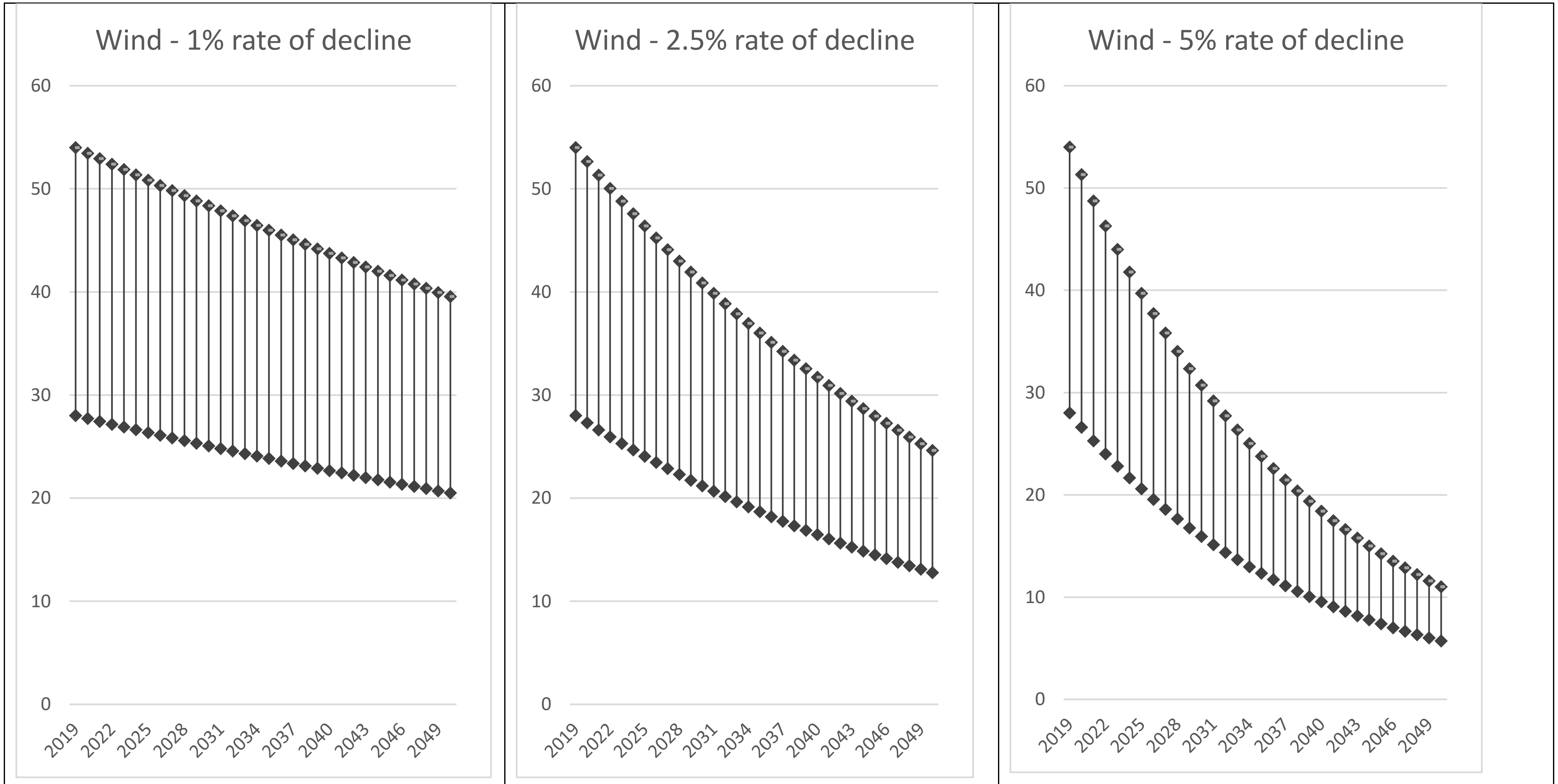
Figure 5 and Figure 6 show that, even with modest reductions in the technology costs, the levelised cost of generating electricity from solar or wind is likely to be low even if one assumes rates of cost reduction much less than those experienced in recent years. If costs continue at 5% per annum (a rate that is just half the pace of that observed by Lazard [141] for solar, and equivalent to that observed for wind), then levelized costs of c. US$10/MWh may be observed for solar by 2050, with similar costs observed for wind. This prediction aligns with many identified in the literature.[143, 144] Even with more modest rates of cost reduction, it is likely that LCOE values of c. 20-30/MWh may be observed by 2050. The implications that this will have for projected levelised cost of hydrogen will now be analysed.

Figure 5: Levelised cost of Electricity: Solar PV



Note: Figure shows expected cost trajectory with various low-bound trajectories of annual cost decline. Lazard estimate a slowdown in cost reduction of 5% for the time period 2015-2019. Figures show further slowdown at 5%, 2.5% and 1% respectively. Even with extreme slowdown, the LCOE of solar energy is likely to be between US$25-45/MWh.

Figure 6: Levelised cost of Electricity: Wind



Note: Levelised Cost of Electricity shown in US$/MWh. Figure shows expected cost trajectory with various low-bound trajectories of annual cost decline. Lazard estimate a slowdown in cost reduction of 7% for the time period 2015-2019. Figures show further slowdown at 5%, 2.5% and 1% respectively. Even with extreme slowdown, the LCOE of solar energy is likely to be between US$20-40/MWh.

B.7 Current and projected levelised costs of hydrogen.

Figure 7 and Figure 8 draw on data collected by the Hydrogen Council [105] which consider LCOH as a function of electrolyser capital cost, the levelized cost of electricity and the expected capacity factor. Conditional on the capital and electricity costs estimated in previous sections, one may identify the likely LCOH values at a given milestone on the path to 2050. Two milestones are chosen for this analysis, 2030 and 2040, with three cost reduction scenarios assumed for each.

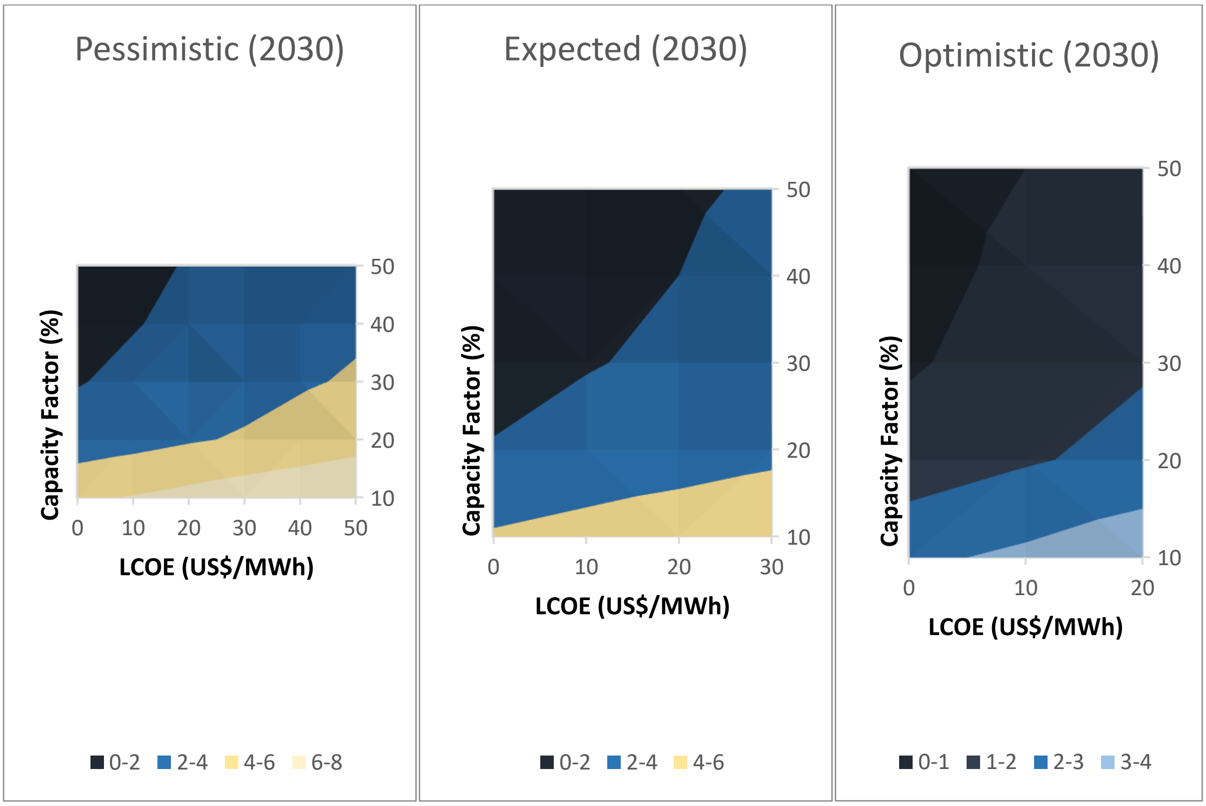
A pessimistic scenario corresponds to a slower rate of capital cost reduction. As the previous section has noted, slower projected rates of electrolyser cost reduction are in the range of 5-18%, yielding a 2030 capital cost in the range of US$500- US$1,100/kW and 2040 capital cost of US$400-US$1,000/kW. We take a central estimate from this range of US$750/kW for the pessimistic scenario. For electricity cost, benchmark pessimistic values are chosen to incorporate a range that is much less than the expected annual rate of cost reduction of 5%. Therefore, we consider a wide range to incorporate a 1%+ rate of annual renewable energy cost reduction, yielding a 2030 electricity cost of $50/MWh or less and a 2040 electricity cost of $30/MWh or less.

An 'expected' scenario corresponds to one of median expected capital cost reduction. An 18% learning rate for capital costs is the expected cost reduction, as the previous section has outlined, yielding an expected 2030 capital cost of c.US$500/kW and an expected 2040 capital cost of c.US$400/kW. For electricity cost, a 5-7% rate of annual renewable energy cost reduction was noted by Lazard [141] to have been observed from the 5-year period preceding their 2020 report, yielding an expected 2030 electricity cost of $30/MWh or less and a 2040 electricity cost of $20/MWh or less.

An optimistic scenario corresponds to one of high expected capital cost reduction, with a learning rate in the range of 18- 31%. This yields an expected 2030 capital cost of c.US$200-$500/kW and an expected 2040 capital cost of US$200-400/kW. To consider an extremely optimistic scenario, we concentrate on a capital cost value of US$250/kW. A 5% rate of annual renewable energy cost reduction is assumed, following that observed by Lazard [141], with a focus on the upper range of potential cost values, where 2030 electricity costs are $20/MWh or less and 2040 electricity costs are $10/MWh or less.

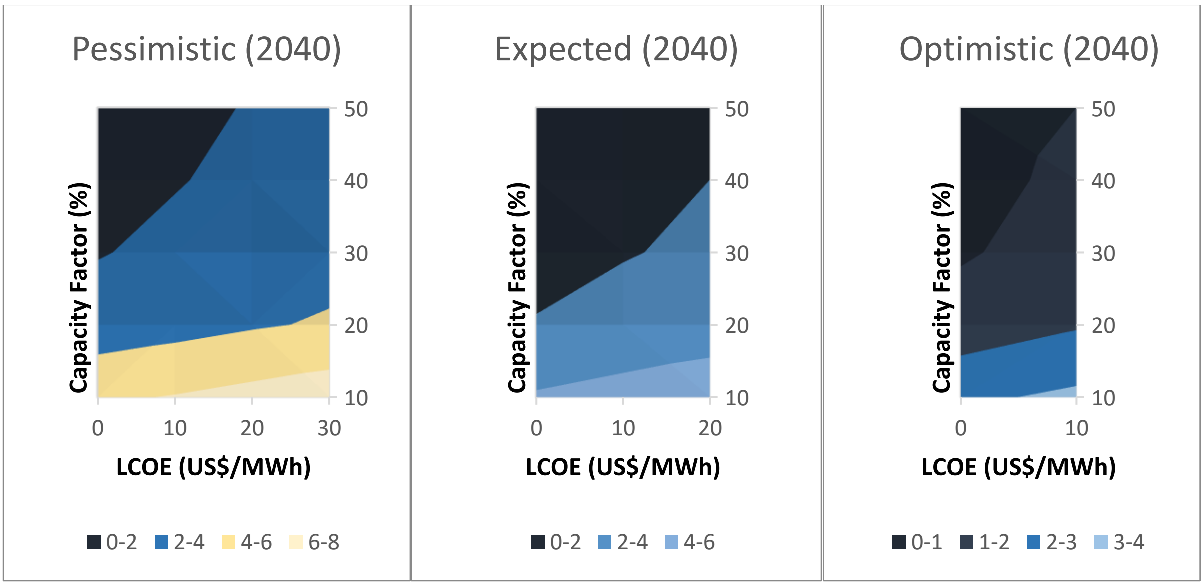
We map these scenarios onto the scenarios of the Hydrogen Council [105] to identify the LCOH. The resulting LCOH figures, conditional on capacity factor, are listed in Figure 7 and Figure 8.

Figure 7: 2030 LCOH (USD/kg) conditional on capacity factor and LCOE



Notes: Data source Aurora Energy Research [2], The Hydrogen Council [103], Hydrogen Council [105]

Figure 8: 2040 LCOH (USD/kg) conditional on capacity factor and LCOE



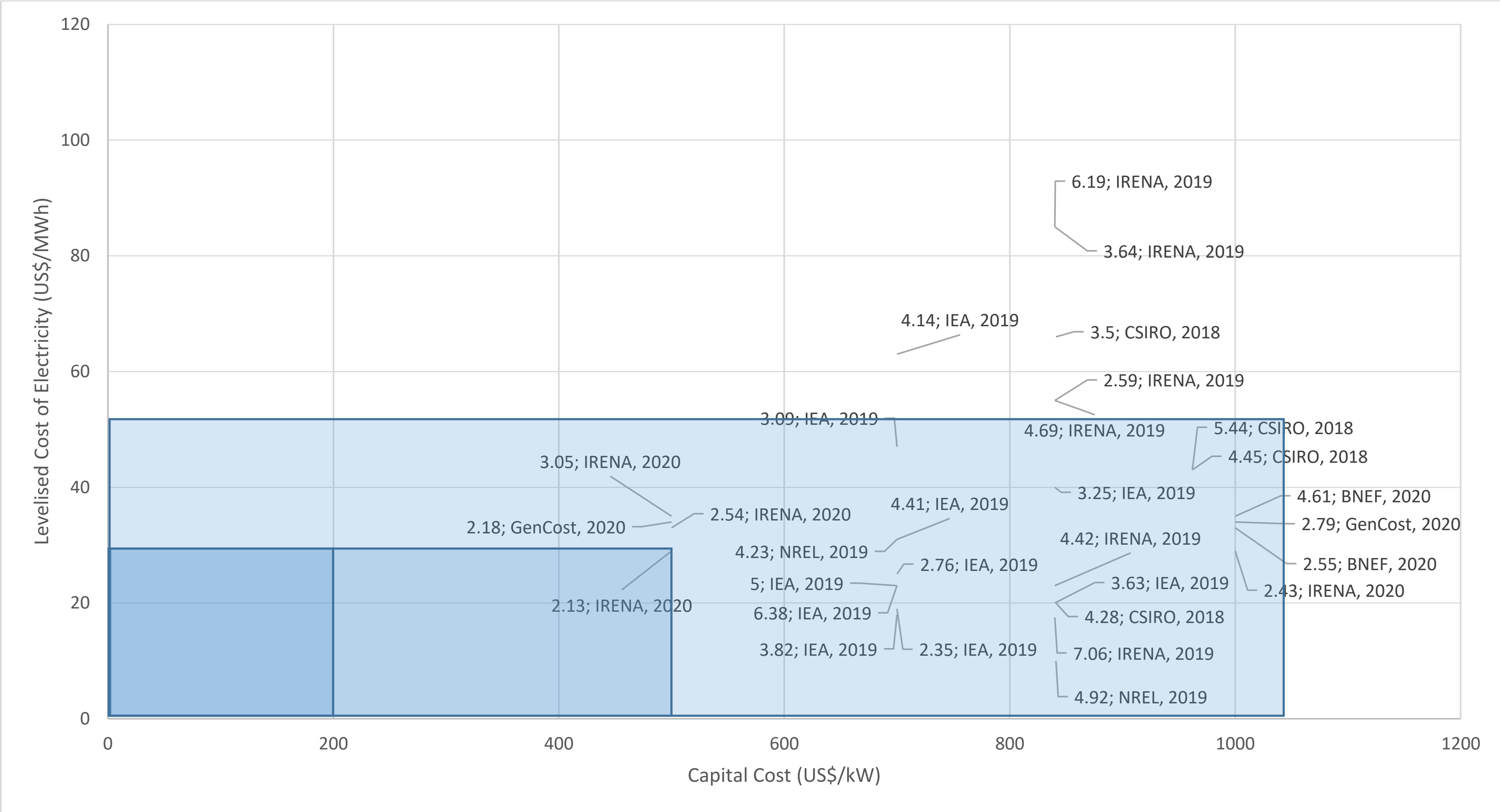
Notes: Data source Aurora Energy Research [2], The Hydrogen Council [103], Hydrogen Council [105]

From these data, a number of findings can be observed. First, once an average cost of electricity of c.$50/MWh is achieved, alongside utilisation rates of 35% or more, there is a reasonable chance of achieving an LCOH of 2-4/kg by 2030. This suggests that renewable-coupled hydrogen may be cost competitive, conditional on expected deployment patterns and the associated cost reductions transpiring. Given current capital and renewable electricity cost trajectories, this is achievable with a reasonable degree of certainty. Indeed, under our optimistic scenario, almost all potential LCOE/capacity factor/electricity cost scenarios yield an LCOH of $4/kg or less. Perhaps the most uncertain aspect surrounding this is the pace of deployment with respect to hydrogen technology deployment.

Longden, Beck [127] review expected LCOH values in the literature, conditional on electricity and capital cost assumptions. Figure 9 and Figure 10 compare the previously calculated cost projections to those sourced in the literature by Longden, Beck [127]. First, Figure 9 shows clearly that to align with reasonable 2030 LCOH values, considerable capital cost reductions must be assumed. One can see that 2030 deployment costs are more optimistic than those currently envisaged by much of the literature, which assume capital costs in the range of the "pessimistic" 2030 cost reduction scenario. This may be due to cost scenarios relating to the immediate future, pre-2030. Cost predictions purported to align with 'long-term' hydrogen cost values, such as those proposed by IRENA and IEA, correspond with the 2030 expected and optimistic scenarios of Figure 9 and Figure 10.

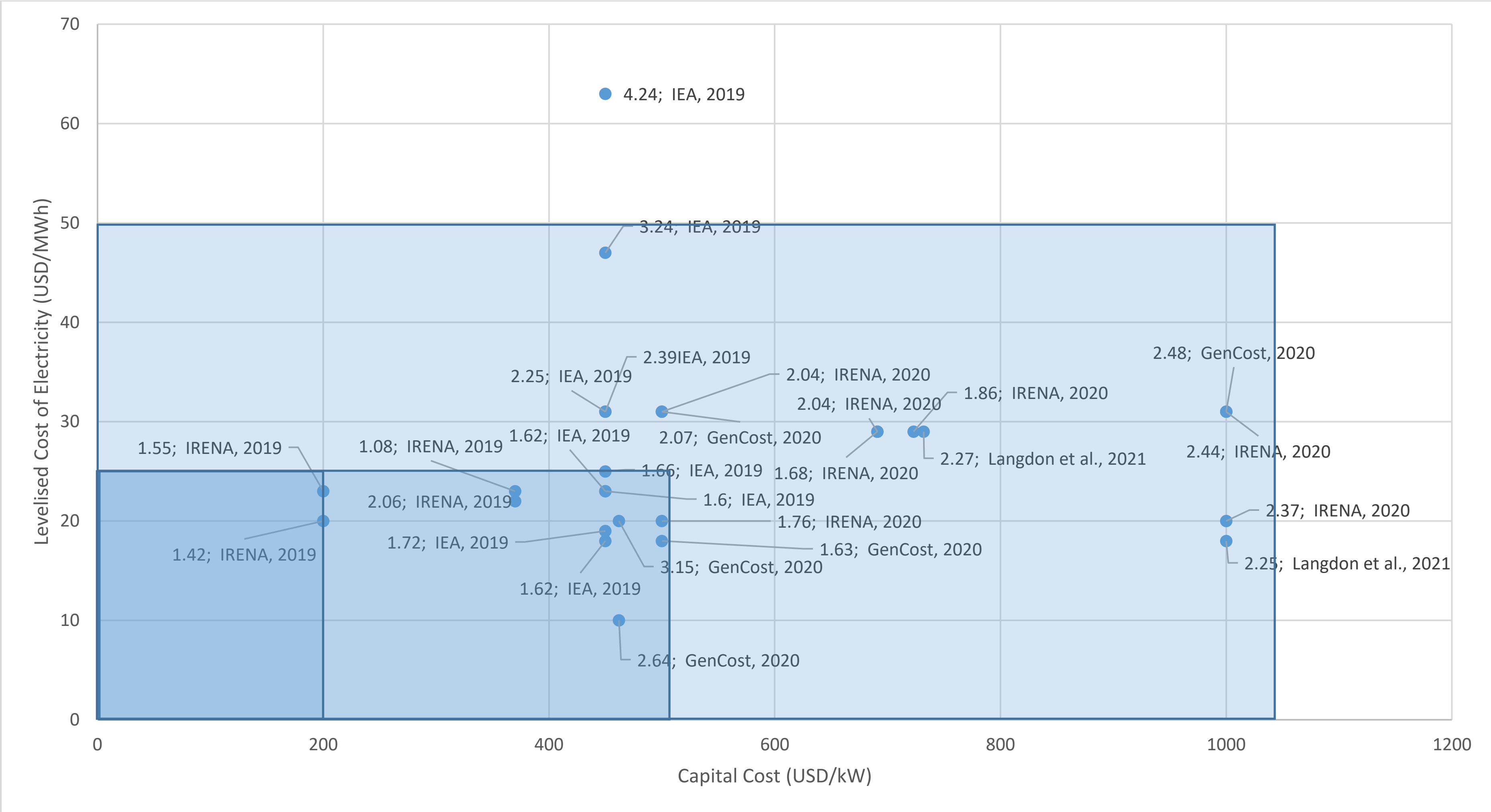
A further observation may be made; reductions in the levelised cost of electricity can result in mid to low-cost hydrogen, in the region of USD4/kg, even if the capital cost of electrolysers is above USD 600/kW. This suggests that there is an added spillover effect of further driving down the cost of renewable electricity generation.

Figure 9: Summary of LCOH estimates in literature (near-term capital costs) & 2030 deployment scenario



Legend: Light blue – pessimistic capital/electricity costs; medium-dark blue – expected capital/electricity costs; dark blue – optimistic capital/electricity costs. Data sources: Aurora Energy Research [2], The Hydrogen Council [103], Longden, Beck [127]

Figure 10: Summary of LCOH estimates in literature (long-term capital costs) & 2030 deployment scenario



Legend: Light blue – pessimistic capital/electricity costs; medium-dark blue – expected capital/electricity costs; dark blue – optimistic capital/electricity costs. Data sources: Aurora Energy Research [2], The Hydrogen Council [103], Longden, Beck [127]

B.8 Cost competitiveness of hydrogen-based technology

This section reviews the expected cost of hydrogen application. We provide insight into the point at which deployment may be viable and the resulting policy response for technology takers/makers. There are four primary applications for hydrogen technology: transport (low, medium and heavy duty vehicles), heat, electricity (generation and storage) and for use in industrial processes. Each will be analysed in turn.

Space Heating

Hydrogen has the potential to serve as an energy carrier to fuel space heating. This may take the form of either building-specific hydrogen-fuelled boilers or a system where heat is produced centrally and distributed through heat networks. Both methods can make use of existing building and energy network infrastructure, should that be available. Existing gas pipelines can accommodate blends of hydrogen of up to c. 40% without upgrade, with network investment required to accommodate hydrogen concentrations that exceed this. Appliance and network upgrade would be required to facilitate blends in excess of 40%.[1, 102, 108] Alternatively, hydrogen can be produced in a centralised boiler and the heat distributed using a heat network.

These technologies are all in the early stages of development and cost projections are therefore speculative. The International Energy Agency [98] have reviewed the cost thresholds at which 100% hydrogen-fuelled space heating becomes competitive with electric heat pump and gas-fuelled boilers. This varies by region, depending on the local cost of gas. Competitiveness is achieved earlier in regions where gas is more expensive. The IEA estimate that, in Western Europe, competitiveness is achieved at LCOH values of c. US$2.75/kg, falling to c. 2/kg in regions with cheaper gas, such as Canada. If the price of carbon is high, cost competitiveness is achieved at a higher LCOH.

For full decarbonisation, competitiveness with electric heat pumps is the benchmark of concern. In Western Europe, competitiveness is achieved at a little over US$2/kg, whereas competitiveness may be achieved between 1-2/kg in other markets including the US, China and Canada.

According to the trajectory of Figure 7 and Figure 8, such a cost reduction could happen by 2030 if there is an LCOE of 20/MWh or less, an expected rate of cost deployment and high capacity factors. Such a cost is more likely to be achieved by 2040. Given that hydrogen for heating requires a considerable lead-in time to accommodate appliance and infrastructure upgrade, policy should anticipate deployment in the order of ten years in advance. Therefore, for deployment in 2040, deployment should initiate conversion in 2030 and no later than 2040, given the 2050 decarbonisation constraint.

Conditional on policy anticipating cost-competitive deployment during the identified windows, a number of further barriers to deployment may need to be anticipated. First, as this is a consumer-based adoption, behavioural factors may come into play. Policy may need to anticipate these, drawing on interventions discussed in the energy efficiency literature. [61] Credit constraints may also exist with pay-as-you-save or similar credit programmes proving effective should these constraints prevail. Heat networks and hydrogen heating may be adopted by a lesser subset of jurisdictions and, as such, any one adopter may be large relative to the total market. Policy decisions may influence the direction of costs and national policy may wish to anticipate this by investing in R&D.

Industrial processes

Hydrogen can be used for ammonia production (the majority of which is used as a feedstock for fertiliser) and as a substitute for fossil fuels in steel production.

Ammonia production

Ammonia is currently produced using the steam methane reforming (SMR) or coal gasification procedures, which emit about 2.5 tons of CO2 per ton of ammonia produced. The baseline cost of carbon-intensive ammonia production is therefore sensitive to the price of carbon.

With a cost of carbon of US$50/t$CO_2$, the International Energy Agency [98] finds that hydrogen-based ammonia production is cost competitive at c. US$1.20-1.30/kg in regions with lower natural gas prices. In regions such as Europe with higher natural gas prices (c.US$7 per MMBtu), the breakeven point occurs at an LCOH of c.US$1.40-1.50/kg, increasing to US$ 1.70-1.80/kg with a carbon price of c.US$50/t$CO_2$. A carbon price of US$200/tCO_2 and a price of gas of c.US$7 per MMBtu results in a breakeven LCOH of US$3/kg.

For hydrogen-based ammonia production to become viable, a high carbon price and low LCOH must be achieved. From the analysis of Figure 7 and Figure 8, it appears that an LCOH of $3/kg or less is likely by 2030 however this is based on the assumption that installation progresses as expected and there is a high capacity utilisation of electrolysers.

Methanol

Green hydrogen can also be used to replace fossil-based processes in the production of methanol. Before considering the cost of carbon, the International Energy Agency [98] estimates methanol production from low-carbon hydrogen is competitive against grey hydrogen at costs of US$0.80-1.50/kg, depending on the region and the cost of natural gas. A carbon price of US$50/t$CO_2$ increases the break-even cost of low-carbon hydrogen only slightly, by US$0.10-0.20/kg. The cost of carbon has less influence on conventional methanol because methanol emits less CO2 relative to natural gas feedstock, with much of the carbon being captured in the methanol end product.[98] As such, it is likely that hydrogen use in methanol production is likely to transpire post-2040 and close to 2050 on the decarbonisation trajectory.

Steel production

Steel production requires high temperatures traditionally provided by the burning of fossil fuels. A blast furnace with CCS is the relative metric against which hydrogen-based steel production may be measured. Hydrogen-based steel production requires hydrogen costs of US$1.80-2.30/kg to become cost competitive in the US, with a higher break-even point in regions with more expensive coking coal, such as Europe or Japan.[98] Competitiveness against conventional blast furnaces will largely depend on the cost of carbon. Given a cost of carbon of USD 50 per ton, H2-DRI can break even with hydrogen costs of about USD 1.60 per kg, assuming a cost of coking coal of USD 200 per ton. With average costs of hydrogen of about USD 2.30 per kg, hydrogen-based steel production can outcompete blast furnaces with CO_2 costs of less than US$ 100 per ton. These ballpark findings suggest that using hydrogen for steel production is requires an optimistic deployment and cost reduction schedule to be cost competitive by 2030, with a more likely trajectory achieving cost competitiveness by 2040.

Policy response

Market signals will likely guide adoption in this field. Policy should ensure that there are no impediments to timely adoption, such as production capacity constraints. Further, there may be scope for policy to ensure the required social capital is in place. This may be in fields such as to establish business connections and to develop an understanding of hydrogen-based production methods to facilitate adoption in a timely manner.

Hydrogen for Electricity Storage

Given the intermittent nature of renewable electricity generation, electricity storage technologies will be required to facilitate decarbonisation of the electricity system. There are many potential storage technologies, of which hydrogen is one. Hydrogen-based storage options suffer from low round-trip efficiency: in the process of converting electricity through electrolysis into hydrogen and then hydrogen back into electricity, around 60% of the original electricity is lost, whereas for a lithium-ion battery the losses of a storage cycle are around 15%. [98] However, hydrogen becomes relatively more cost-competitive when longer durations are considered, benefitting from the relative low capital costs for energy storage volumes (the investment costs to develop underground salt caverns or storage tanks). International Energy Agency [98] finds that compressed hydrogen becomes the most economic option for discharge durations beyond 20–45 hours.

Long discharge duration primarily serves inter-seasonal electricity storage in electricity systems with a high penetration of intermittent renewables. Albertus, Manser [99] provide a benchmark calculation to suggest that day/week storage durations may be required at c.80% penetration, while seasonal storage durations may be required at c.90% intermittent renewables penetration. Island systems such as Ireland and ERCOT (Texas) may be more sensitive to this requirement.

It is this technological requirement that will be the determinant of deployment, in the first instance, followed by cost-competitiveness relative to alternatives such as interconnection. Such degrees of renewables penetration may be experienced c.2030-2040. Markets with high degrees of renewables penetration, such as Ireland and Germany, anticipate 70% and 65% intermittent renewables penetration by 2030, respectively.[18, 100] It may be reasonably expected that longer-term storage will begin to be required in the 2030-2040 time period.

The policy implications for this potential technological application are quite clear; technology-neutral electricity market incentives should guide investment in this regard. Liberalised electricity markets tend to have strong incentives and often bespoke markets for investment in capacity. Longer-term storage forms part of the contracted capacity as intermittency grows as a proportion of total generation. This should be technology-neutral, with hydrogen-focused policy unnecessary outside of general R&D-focused policy interventions.

The requirement for longer-term- electricity storage is unlikely to transpire until the 2030-2040 time period for many markets. Public policy should anticipate this requirement by ensuring that the correct incentives are in place to allow for the correct balance of storage capacity to emerge.

Hydrogen use for power-to-gas

Instead of storing the hydrogen, it can be blended with natural gas and used in the gas network for heating and cooking. This is known as 'power-to-gas' and is an alternative form of storage which exploits the flexibility of the gas network to accommodate the lack of flexibility of the electricity network. In doing so, the carbon content of gas consumption is reduced. Although the exact level is disputed, several studies suggest that up to 15–20% hydrogen blend by volume (vol%) should be technically achievable without infrastructural investment [113]. P2G may benefit energy systems by providing an additional cost-effective means of accommodating volatility in electricity generation.

A number of studies exist to calculate the cost of power-to-gas, where hydrogen electrolysis is coupled with intermittent renewables. In many cases, hydrogen is produced at a cost far in excess of that which would be deemed cost-effective[112, 113], perhaps due to low capacity factors. However, despite the expense of direct coupling, there may be a use for P2G. P2G enhances the value of the generation portfolio for certain renewable generators.[114] Scamman *et al.* [17] found that a 1 MW P2G plant could be profitable in the UK in 2030 if it had access to free excess electricity and demand-side management markets. However, these cases are still challenging due to the limited hours where balancing markets or surplus renewable energy are available.

Policy response

There is no apparent social value of power to gas that is not represented by existing market signals which will likely guide adoption in this field. However, these market signals must be received by firms, with appropriate short-term electricity trading markets required. There is therefore a role for energy policy to ensure that a complete set of liquid electricity markets exist such that value creating technologies such as power to gas are adopted where social value for such adoption exists.

Electricity generation

Hydrogen may be used as a fuel in existing fossil fuel turbines and for electricity storage. Turbine manufacturers such as GE and Siemens are already developing gas turbine equipment that can operate on 100% hydrogen, with the HYFLEXPOWER demonstration project expected to be running c.2023.[97] The availability of commercial-level hydrogen turbines is unknown but unlikely to be available pre-2025, with pre-2030 deployment demonstrating a rapid development trajectory.

Hydrogen is an energy carrier that could be particularly useful for medium to long-term electricity storage. Hydrogen-based storage options suffer from low round-trip efficiency and are therefore less efficient than other short-term storage options. Hydrogen becomes relatively more cost-competitive when longer durations (durations beyond 20–45 hours) are considered.[98]

Policy response

Technology-neutral decarbonisation should be incentivised with respect to electricity generation, and the adoption of hydrogen as part of a decarbonised portfolio of technologies should be guided by technology-neutral policy targeted at specific market failures. This includes a target-consistent high and rising carbon price to internalise the environmental externality. Should there be incomplete markets for risk, technology-neutral policy intervention may be considered. As discussed with respect to power-to-gas, there is a role for energy policy to ensure that a complete set of liquid forward and intra-day markets exist such that value-creating technologies are adopted where social value for adoption exists.

Transport

In the transition to a decarbonised transport fleet, passenger cars and light/medium/heavy-duty commercial freight vehicles may all be powered by hydrogen. The extent with which hydrogen will be deployed in these categories is predicated on (1) the costs relative to electric or biomass-powered alternatives and (2) the extent with which required services can be delivered by an electric or biomass alternative. The cost competitiveness of passenger cars, heavy/medium duty and light duty vehicles will now be discussed in turn.

Passenger cars

Fuel cell electric vehicles, the frontrunning hydrogen-based technology, currently have higher capital and operating costs than Battery Electric Vehicles (BEVs) but have the potential for considerable cost reduction as manufacturing volumes rise, and could end up as cheaper alternatives.[1, 107, 108] Hydrogen vehicles also have attractive non-financial attributes regarding refuelling time, range and infrastructure requirements relative to electric alternatives.[1] McKinsey and Co. [106] suggest that hydrogen for private car transport becomes cost competitive with electric alternatives at around $2/kg. Figure 7 shows a medium-low possibility that hydrogen will be available at a production cost of $2/kg or less in 2030, conditional on the assumed deployment trajectory.

Medium/Heavy Duty Vehicles

Medium/Heavy Duty Vehicles (MDV and HDV, respectively) comprise categories such as buses and trucks. Relative to light duty vehicles, there is a relatively low volume of manufacturing output and a greater requirement for energy density. Aside from cost considerations, these characteristics position hydrogen as a more suitable fuel than electricity.[22, 109-111]

McKinsey and Co. [106] find that hydrogen for freight transport becomes cost competitive with other low carbon alternatives at an LCOH value of about US$3/kg. Figure 7 and Figure 8 show that there is a medium-low likelihood of achieving an LCOH of $3/kg or less before 2030, under the expected hydrogen deployment trajectory and rate of cost reduction. There is a greater likelihood of this being achieved post-2030, primarily driven by reductions in the levelised cost of electricity. Hydrogen may become competitive with battery transport by 2030 under an accelerated deployment trajectory. It is, however, more likely that hydrogen for MDV and HDV becomes cost competitive during the 2030-2040 time period.

These are findings backed up by other sources in the literature. The hydrogen-fuelled vehicle is uncompetitive with the diesel vehicle, even under very high carbon prices of US$150/t$CO_2$, unless there are considerable capital cost reductions.

One can see that low hydrogen costs of c.US$2/kg are required for cost-effective deployment, even in low CO2 tax scenarios. For 4/2 rigs, a higher carbon tax is required in addition to a low hydrogen cost. From this analysis, one can conclude that low capital costs are a stronger driver of deployment than high carbon tax – this should be a focus for innovation policy.

4.1.1 Cost competitiveness for light-duty vehicles.

Jones, Genovese [145]compare the total cost of ownership for various brands of light-duty vehicles, finding that hydrogen models struggle to break even with electric alternatives. Under current capital costs, the hydrogen vehicle does not break even with the diesel-fuelled vehicle under any modelled scenario of hydrogen cost or CO_2 price. Breakeven may occur if there is a considerable reduction in the capital cost of these vehicles relative to non-hydrogen alternatives.

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