Energy Community

Study on the potential for implementation of hydrogen technologies and its utilisation in the Energy Community

Part II: Economic analysis

Gas

ECA, E4tech

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Abbreviations and acronyms

BESS	Battery energy storage systems
BEV	Battery electric vehicles
BNEF	Bloomberg New Energy Finance
CCGT	Combined cycle gas turbine
CCUS	Carbon Capture Utilisation and Storage
CP	Contracting Parties
FCEV	Fuel cell electric vehicles
HGV	Heavy Good Vehicle
ICCT	International Council on Clean Transportation
IEA	International Energy Agency
LCOE	Levelised cost of energy
LNG	Liquified natural gas
Low carbon hydrogen	Hydrogen produced from fossil fuels with CCUS or from nuclear plants, or which is sourced from the electricity grid with a carbon intensity of <100kgCO_2/MWh
MeOH	Methanol (chemical formula CH_3OH)
NH_3	Ammonia
O&M	Operating and maintenance
OCGT	Open cycle gas turbine
Renewable hydrogen	Hydrogen produced from renewable energy
RES	Renewable energy sources
SEETO	South-East Europe Transport Observatory
SMR	Steam methane reforming
TAP	Trans Adriatic Pipeline
TSO	Transmission system operators
VRE	Variable renewable energy

1 Introduction

This report is the second of four separate but related reports under the *Study on the potential for implementation of hydrogen technologies and its utilisation in the Energy Community.* The first report documented the current state of play internationally with regards to hydrogen, including its drivers, its potential role in the energy system and possible end-use applications, and the policy mechanisms and strategies being employed worldwide to facilitate the introduction and/or scaling up of hydrogen.

The present report builds on this review and presents the results of economic analysis we have undertaken to provide guidance on **which hydrogen technologies might have the greatest economic potential for the Contracting Parties** (CPs), both in the short term and further into the future (2030s and beyond), after accounting for forecast cost reductions. For this purpose, we focus on the main end-use sectors (transport, industrial applications, power and heat) and on sub-sectors within these that show the greatest potential for hydrogen and which are likely to be of most relevance to the CPs. Our analysis builds on other reputable studies undertaken in recent times, but tailors this to the extent possible to the circumstances of the CPs and attempts to draw out the implications for them.

This analysis together with its two accompanying reports – the first covering the international review and a third profiling and comparing the CPs' institutional, policy and infrastructure make-up with respect to hydrogen inform the development of recommended actions for the CPs in incorporating hydrogen in their strategies and policy toolkits, which are captured in the fourth and final *Synthesis Report*.

This report is structured as follows:

- In Section 2, we conduct netback analysis of the potential for hydrogen in trucking transportation and buses relative both to prevailing diesel prices across the CPs and to battery electric vehicles (as the other decarbonisation option);
- In Section 3, we consider potential industrial applications for hydrogen in the ammonia, iron and steel, and methanol sectors, all of which are highly energy intensive, and difficult to electrify, and therefore would have high decarbonisation value, while they also represent a material proportion of industrial output in many of the CPs;
- In Section 4, we consider the case of hydrogen in the power sector;
- In Section 5, we compare hydrogen-for-heat with other heating options on a variable cost basis.

The report also contains six annexes with the detailed assumptions employed in our analysis of the various end-use sectors, as well as a review of recent carbon price projections, which are contrasted with the calculated 'breakeven' carbon prices for hydrogen in the industrial, power, and heating sectors.

Key findings

Transport

- The short-term prospects for hydrogen's economic competitiveness are limited but CPs with high diesel prices, like Albania and Serbia, may wish to explore feasibility and pilot studies for long-haul hydrogen trucking or buses.

- The economics of hydrogen fuel cell electric vehicle (FCEV) urban buses are less promising relative to electric battery urban buses.

- Scaling up hydrogen refuelling infrastructure is likely to be the largest barrier to hydrogen transport, which can be overcome by establishing dedicated FCEV transport routes, where refuelling needs are predictable and high volume. This would require the CPs to coordinate along regional heavy traffic routes.

Industrial applications

- Electrolyser-based **ammonia production** is likely to be higher cost than production from fossil fuels, even after accounting for carbon capture utilisation and storage (CCUS) costs. If CCUS cannot be sufficiently scaled-up, carbon prices of over €200/tCO_2 could make electrolyser-based production competitive. The required carbon price could be limited to €100+/tCO_2 if the electrolyser is supplied by low variable cost, dedicated RES.

- Significant carbon prices (€125-210/tCO_2) would be required to make **electrolyser-based DRI-EAF steel production** competitive with coal-fired BOF plants or natural gas-fired EAF plants. However, there are numerous ongoing studies and pilot projects of CO_2 avoidance or management in the steel industry and the CPs' steel industries should monitor these developments, particularly as they seek to align their economies with EU environmental regulations.

- Electrolyser-based **methanol production** is unlikely to be economically competitive with natural gas-based methanol production in the near term, but it may be a long-term option in CPs with an abundance of low-cost renewable energy sources (RES) or as part of a fully decarbonised economy

- For other **high heat applications**, such as the cement industry, carbon prices of over €200/tCO_2 are likely required and sustainable biomass may be a more promising avenue for decarbonisation. Hydrogen may still be an option for "hard to reach" industries where CCUS proves impractical and retrofitted pipelines or small-scale on-site electrolysers are possible, or where sustainable bioenergy supply is limited.

Power storage

- For short-duration discharge requirements, battery energy storage systems (BESS) are highly likely to remain the most cost-efficient option. The storage of hydrogen for power only offers a lower cost than BESS at discharge durations above eight hours.

- However, in electricity systems with increasing shares of variable renewable energy (VRE), there may be prolonged periods of scarce supply, making storage with longer discharge durations more valuable. Our analysis suggests that for lower capacity factors (<15%), hydrogen power storage can be expected to be cost competitive with CCUS-fitted natural gas power plants and up to 30% in favourable conditions (high natural gas prices and low hydrogen production costs).

- For CPs where natural gas is not readily available and the alternatives are CCUS-fitted lignite or coal plants at low load factors or building new natural gas networks, the competitiveness of hydrogen will be significantly enhanced.

Domestic heating

- Hydrogen will struggle to compete on a *variable cost basis* with other heating options. Given that hydrogen heating will also require other significant investment costs, whether through building/retrofitting pipelines and converting appliances, it is unlikely that hydrogen can be an economically competitive heating option unless a few conditions play out:
  - An existing gas grid can be cost effectively retrofitted;
  - A carbon price of over €100/tCO_2 is applied;
  - Electricity distribution grid limitations prevent the installation of heat pumps (which also face significant installation costs, particularly in older buildings); and
  - Accelerated and aggressive decarbonisation policies include requirements for zero carbon heating, i.e., gas heating only incurring a carbon price is not considered sufficient.

- Hydrogen heating may have wider system benefits if sufficient geological storage is available to respond to seasonality, which will depend on CPs' geologies and perhaps in the long term the potential for cross-border hydrogen trade from CPs or EU neighbours with storage potential.

- While a 100% switch to hydrogen heating may not be feasible in the near term, blending hydrogen in existing natural gas networks could be a transitional option.

2 Transport

Ongoing trends suggest that battery electric vehicles (BEVs) are likely to become the dominant decarbonisation option for personal vehicle transport and small-medium sized vehicles making short-medium distance trips. However, hydrogen transport, in the form of fuel cell electric vehicles (FCEVs), may still have a role in a decarbonised future for long-haul heavy-vehicle transport, such as trucks and buses, and niche applications, such as forklifts.

Unlike BEVs, refuelling time for FCEVs is similar to that of gasoline or diesel vehicles and they may be able to cost effectively achieve ranges of 500+ km. However, like BEVs, the cost of FCEVs needs to come down, their efficiency must continue to improve, and a large amount of hydrogen refuelling infrastructure would be required, at potentially significant cost. Nevertheless, the capital and running costs of FCEVs are expected to fall in the future as the technology improves and economies of scale emerge as vehicle production ramps up.

We consider the economic case for hydrogen long-haul trucking and buses in the CPs through a netback analysis (described in Annex A2.1) of current and projected total ownership costs for hydrogen versus diesel-fuelled and BEV transport.[1] We seek to estimate the maximum hydrogen production cost such that hydrogen becomes competitive with transport based on diesel (the current alternative fuel) and BEV (the alternative low carbon option).[2] However, we first consider the current and expected costs of preparing and distributing hydrogen to FCEVs, as well as the required fuelling stations, in order to demonstrate the importance of the cost of hydrogen "at the nozzle".

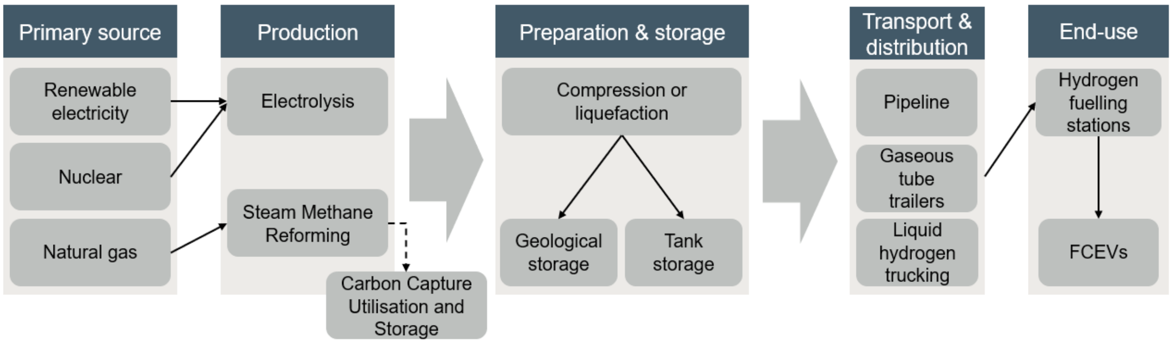
2.1 Hydrogen distribution and storage costs for transport

Figure 1 illustrates the supply chain for supplying FCEVs with renewable or low-carbon hydrogen. Our netback analysis looks to "net off" the costs in between production and end-use to arrive at a netback production price for hydrogen.

For hydrogen vehicles today, the cost "at the nozzle", including the cost of hydrogen production, typically ranges around €8.5-10.2/kg[3]. One of the biggest contributors to this cost (up to 50%) is the fuelling stations, which are currently in scattered locations and have low utilisation rates. However, the cost at the nozzle could reduce to €3.4-4.2/kg by 2030, with lower distribution costs accounting for 70% of this reduction, due to a combination of economies of scale, increased station size and increased utilisation.[4]

[1] A total cost of ownership approach considers both asset acquisition costs and the costs of operation over the expected life of the asset. Projections are made for 2030, which has the richest available datasets for transport decarbonisation.
[2] In Annex A2.2, Table 7 lists the prevailing price of diesel for each CP, sourced from https://www.globalpetrolprices.com/, and Table 8 provides our assumptions for vehicle and operation and maintenance (O&M) costs, associated CO_2 emissions, and fuel consumption.
[3] All figures from external sources have been converted to Euros. Currency conversions assumed throughout this report: $/€: 1.18. €/£: 1.13.
[4] Hydrogen Council, Path to hydrogen competitiveness: A cost perspective, 20 January 2020, p. 38.

Figure 1 Hydrogen supply chain for FCEVs



Source: ECA.

Similarly, the International Council on Clean Transportation (ICCT) estimates that hydrogen fuelling infrastructure investment costs per vehicle would be about €215,000 with only 100 hydrogen trucks on the road – almost equal to the cost of a hydrogen-fuelled heavy goods vehicle itself - but this cost would decline to about €90,000 if 10,000 hydrogen trucks were operating.[5] For comparison, data from the South-east Europe Transport Observatory (SEETO) suggests that ~13,500 heavy good vehicles per day were operating along 17 major routes and traffic corridors across the West Balkans in 2016.[6] While any single CP may not have the scale to cost-effectively introduce hydrogen fuelling infrastructure, **the CPs may collectively have the scale to achieve significant economies of scale with highly utilised hydrogen fuelling infrastructure along shared major traffic routes**.

There are three primary options for hydrogen distribution and storage for supplying FCEVs:

- At small scales and short distances, **gaseous transport by tube trailers** is likely to be the primary distribution option. At <10 tonnes/day and <100 km distance, and assuming daily cycling, Bloomberg New Energy Finance (BNEF) estimates a gaseous truck transport cost of €0.55-1.46/kg.[7]

- At longer distances, transport and storage by liquefaction is preferred.[8] BNEF estimates that liquid hydrogen transport is ideal for small volumes (<10 tonnes/day) and large distances (>100km), with an estimated cost range of €0.81-5.68/kg.[9]

- The most economic route would be if both pipeline transport and geological storage are available *and* feasible, i.e., volumes are high enough.

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[5] Hall, D. and N. Lutsey, 'Estimating the infrastructure needs and costs for the launch of zero-emission trucks', ICCT White Paper, August 2019, Table 8. This study uses the greater Los Angeles area as the basis for its cost estimates, but the authors suggest the results should be generalisable to other high-volume freight areas with a mix of high- and low-distance freight routes.
[6] South-East Europe Transport Observatory (SEETO), Comprehensive Road Network traffic indicators 2015 and 2016, SEETIS 2018.
[7] BNEF, 2020, Hydrogen Economy Outlook: Key messages, Figure 4. A 'highest reasonable cycling rate' is assumed.
[8] Furthermore, Daimler Truck AG and Linde are collaborating to develop liquid hydrogen fuel cell trucks (https://www.daimler.com/investors/reports-news/financial-news/20201210-refuelig-liquid-hydrogen-trucks.html), meaning hydrogen delivery should also be liquid.
[9] BNEF, 2020, Hydrogen Economy Outlook: Key messages, Figure 4.

- European gas transmission system operators (TSOs) recently estimated a levelised pipeline transport cost of €0.07-0.23/kg/1,000km (~€2.3-7.7/kWh/1,000km), depending on how much of the hydrogen pipeline network is retrofitted versus greenfield.[10]
- Geological storage costs should be less than €0.5/kg (€16.7/kWh),[11] and potentially as low as €0.18/kg (€6.0/kWh).[12]
- This suggests total pipeline transport and geological storage costs at a range of €0.25-0.76/kg (~€8.3-25.3/kWh).

Ultimately, the optimal hydrogen delivery model for transport will have to be confirmed on a case-by-case basis, depending on a combination of available options, e.g., whether an existing pipeline network is available, delivery volumes, and population density and size (and thus delivery distance).[13]

For our netback analysis, we use recent estimates by the Hydrogen Council of current and projected costs for hydrogen preparation[14], distribution, and fuelling stations (Table 1). It is crucial that these estimates also include fuelling station costs, which allows for estimating the final cost "at the nozzle", as they are the highest cost component today and have the most potential for cost reductions. Distribution and storage costs are significant today but are projected to converge around €1.8-1.9/kg for each option in 2030 (at their optimal level of volumes and distance) if potential cost savings and utilisation rates are realised.

Table 1 Options and costs of hydrogen distribution for transport

	2020 (€/kg)	2030 (€/kg)	Description
Gaseous trucking (estimate for low volumes and short distances)			
Preparation	0.7	0.3	• Tube trailers transporting compressed hydrogen • Appropriate for low volumes (<10 tonnes/day) and short distances (<100km)
Distribution	0.8	0.7	
Fuelling station	4.5	0.9	
Total	**6.0**	**1.9**	
Liquid trucking (estimate for low volumes and medium-long distances)			
Preparation	1.4	0.9	• Tanker trucks transporting liquid hydrogen • Appropriate for low volumes (<10 tonnes/day) and long distances (>100km) • Best option at longer distances if pipelines are not feasible/available
Distribution	0.3	0.2	
Fuelling station	3.7	0.7	
Total	**5.4**	**1.8**	
Pipelines (new) (estimate for high volumes)			

[10] Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, Teréga, European Hydrogen Backbone: How a dedicated hydrogen infrastructure can be created, July 2020, Table 2.
[11] IEA, 2019, Future of Hydrogen, 69.
[12] Ahluwalia, R.K., et al., 'System Level Analysis of Hydrogen Storage Options', U.S. DOE Hydrogen and Fuel Cells Program, 2019 Annual Merit Review and Peer Evaluation Meeting.
[13] For example, see modelling for a selection of U.S. cities by Yang, C. and J. Ogden, 2007, 'Determining the lowest-cost hydrogen delivery mode', *International Journal of Hydrogen Energy*, 32 (2), 268-286.
[14] Compression for gaseous trucking; liquefaction for liquid trucking.

	2020 (€/kg)	2030 (€/kg)	Description
Preparation	0.3	0.2	• Appropriate for medium-high volumes (>10 tonnes/day) and delivering to multiple high-capacity users • Lowest cost option if volumes are high enough • Ideally use retrofitted pipelines rather than building new pipelines to limit investment costs
Distribution	1.4	0.3	
Fuelling station	4.9	1.4	
Total	**6.5**	**1.9**	

Source: Hydrogen Council, Path to hydrogen competitiveness: A cost perspective, 20 January 2020, Exhibit 16; BNEF, 2020, Hydrogen Economy Outlook: Key messages, Figure 4.

2.2 End-use: Trucking

Table 2 presents netbacks for *produced* hydrogen relative to prevailing retail diesel prices for each CP.[15] This is an important distinction given the netback calculation is relative to reported diesel *retail* prices, which will reflect differing local taxes, retail mark-ups, distribution costs, etc across the CPs. Diesel prices will fluctuate over time, but the latest reported prices provide an indication of the current cost of diesel transport and the relative competitiveness of hydrogen/electric vehicle transport for each CP today. Low diesel prices in a CP today may indicate there is scope to introduce new environmental taxes while remaining competitive. However, it may also indicate that a transport sector may struggle to adjust to a higher fuel cost environment having grown accustomed to low diesel prices.

We estimate how low hydrogen production costs need to be for the total cost of ownership (TCO) of hydrogen transport to be competitive with prevailing diesel prices, assuming the hydrogen distribution cost projections in Table 1 are also realised. The produced hydrogen netbacks can be compared to indicative hydrogen production cost projections (see Annex A1). We assume liquid trucking as the preferred hydrogen distribution method for our calculations given its economics over longer distances, although gaseous transport may be the preferred option at smaller scales and shorter distances.[16]

Table 2 Produced hydrogen and electricity netbacks for FCEV (liquid trucking distribution) and BEV (catenary) trucking by Contracting Party

	FCEV (€/kg / €/kWh)		BEV (€/kWh)	
Contracting Party	Today	2030	Today	2030
Albania	-0.3 / -0.01	**3.5 / 0.11**	0.10	0.16
Bosnia & Herzegovina	-1.2 / -0.04	**2.7 / 0.08**	0.05	0.12
Georgia	-2.8 / -0.08	1.3 / 0.04	-0.03	0.05
Moldova	-2.3 / -0.07	1.7 / 0.05	-0.00	0.07
Montenegro	-0.8 / -0.03	**3.0 / 0.09**	0.07	0.14
North Macedonia	-1.5 / -0.04	**2.5 / 0.08**	0.04	0.11

[15] Using January 2021 data from www.globalpetrolprices.com. Final retail prices will reflect local taxes, retail mark-ups, distribution costs, etc.
[16] For CPs where an existing gas network may be available to be retrofitted for hydrogen distribution for transport, such as Ukraine, the economics of hydrogen transport may be slightly improved.

Contracting Party	FCEV (€/kg / €/kWh) Today	FCEV (€/kg / €/kWh) 2030	BEV (€/kWh) Today	BEV (€/kWh) 2030
Serbia	0.2 / 0.01	**3.9 / 0.12**	0.12	0.18
Ukraine	-2.2 / -0.07	1.9 / 0.06	0.00	0.08
Kosovo*	-0.9 / -0.03	**3.0 / 0.09**	0.07	0.13
Indicative production cost (€/kg)	**Today**	**2030**		
Renewable hydrogen	5.1	2.4		
Low-carbon hydrogen	1.8	1.6		

Source: Consultant analysis. Prices in **bold** reflect if the produced hydrogen netback is above the *indicative* renewable hydrogen production cost. Liquid trucking distribution of hydrogen, but assuming costs for gaseous hydrogen in the truck. For reference, add €5.4/kg for today and €1.8/kg for 2030 to arrive at the *total* delivered hydrogen netback price, including distribution, storage, and fuelling station costs, as per the projected costs in Table 1. Indicative production costs reflect 'average' resources, as per the forecasts in Annex A1, but note that production costs will vary widely by location in practice.

We see that hydrogen is decidedly uncompetitive with diesel-fuelled trucking across the CPs today, requiring *negative* hydrogen production costs to be competitive outside of Serbia (which has a reported diesel price of €1.2/l). However, this may change in the future as FCEV costs decline, fuel efficiency improves, environmental/carbon taxes are added to diesel prices, and scale-up and increased utilisation lower distribution costs. The vehicle cost of hydrogen trucks is expected to drop by 20-30% over the next decade and fuel efficiency may improve by 15%.[17] The Hydrogen Council projects that the cost of liquid trucking distribution could fall from €5.4/kg today to €1.8/kg, including an 80% decline in fuelling station costs. If such cost reductions can be achieved by 2030, we see in Table 2 that even Georgia, where the produced hydrogen netback is calculated to be -€2.8/kg today, could have a netback of €1.3/kg by 2030.

We contrast these calculations with a netback of delivered electricity for BEV trucks supplied by overhead catenary infrastructure.[18] The required battery sizes for long distance haulage likely make standalone BEV trucks uneconomic. However, there is ongoing research on the economics of using overhead catenary infrastructure as a solution to this issue,[19] even after accounting for the significant infrastructure investments.[20] Battery sizing needs are lowered by the electricity being supplied by overhead wires along dedicated, high-traffic routes, while an onboard battery can still be used for shorter routes without catenary lines.

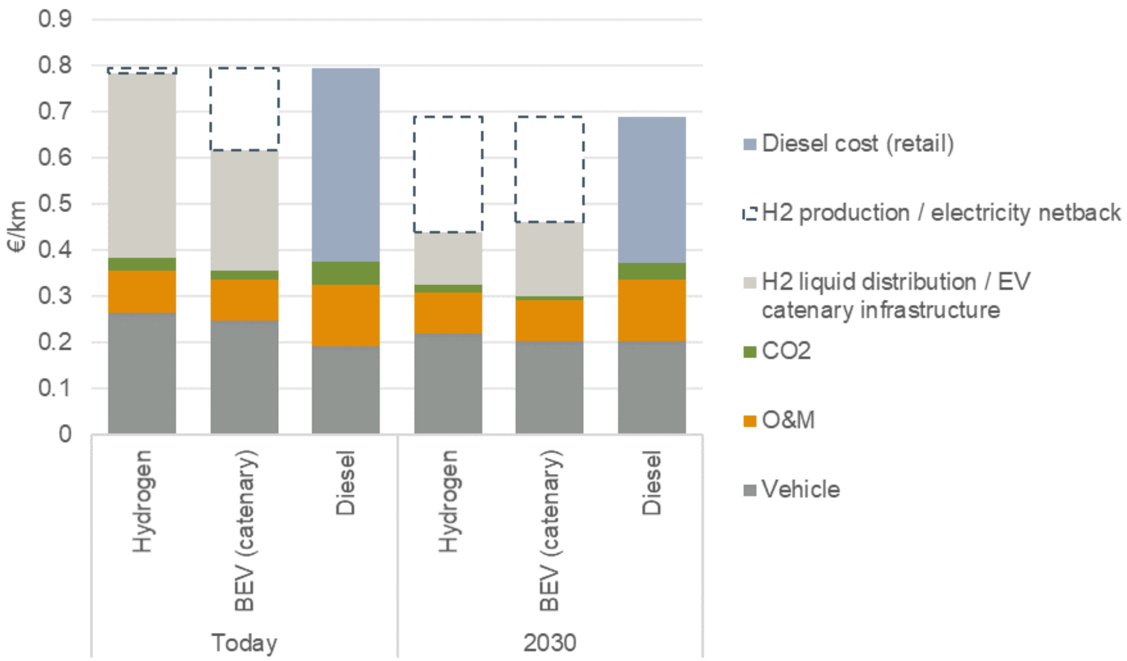
We see that the netback electricity prices are generally low (or negative) for the CPs today, except for the cases of Albania and Serbia due to their high (relative to the CPs) reported diesel prices (€1.1/l and €1.2/l, respectively). This aligns with other recent modelling that suggests BEV trucks with catenary infrastructure could be the most cost effective

[17] See Transport & Environment, 'Comparison of hydrogen and battery electric trucks', June 2020 and Moultak, M. et al, 'Transitioning to zero-emission heavy-duty fright vehicles', ICCT White Paper, September 2017, Table A3. The cost of diesel transport can also be expected to increase due to the implementation of carbon prices and tighter emissions regulations.
[18] The electricity netback is net of catenary infrastructure costs, so it can be considered the netback of electricity delivered to the catenary infrastructure.
[19] Inductive dynamic charging embedded in roadways is another proposed solution for long distance BEV trucks.
[20] The German Transport Ministry has estimated an investment cost range of €1.9-3.9m/km.

decarbonisation option for long distance trucking.[21] However, even if BEV trucks with overhead catenary infrastructure may prove more economic than FCEV trucks for some CPs, there will likely still be many long distance routes where installing overhead wiring (or embedded dynamic charging roadways) is impractical and FCEV trucks are the preferred (and only) decarbonisation option.

Figure 2 stacks the total ownership costs and illustrates the required netbacks of FCEV and BEV (catenary) trucks relative to diesel for Serbia, which is the only CP which exhibits a positive produced hydrogen netback figure today, as reported in the calculations for all the CPs in Table 2 above, albeit at an unfeasibly low level of €0.2/kg. Lower capital costs, improved fuel efficiency, and an assumed decline in the carbon intensity of hydrogen production all contribute to hydrogen's cost decline, but it is apparent that the most significant factor is whether hydrogen distribution cost reductions can be achieved. Much of these distribution cost decreases could initially be realised along dedicated FCEV truck routes where fuelling stations would be guaranteed high utilisation rates.

Figure 2 FCEV and BEV (catenary) truck netback calculations per km for Serbia



Source: Consultant analysis

2.3 End-use: Buses

A netback exercise for long-haul bus transport would have similar findings to trucking. The Hydrogen Council finds that long-haul FCEV buses are about 30% higher cost than their

[21] See recent estimates from Moultak, M., et al., 'Transitioning to zero-emission heavy-duty freight vehicles', ICCT White Paper, September 2017 or Hall, D. and N. Lutsey, 'Estimating the infrastructure needs and costs for the launch of zero-emission trucks', ICCT White Paper, August 2019.

diesel equivalents today, but they can be lower cost in the future and are marginally lower cost than long-haul BEV buses at ranges above 400 km.[22]

We instead consider a produced netback modelling exercise for FCEV (supplied by liquid trucking) and BEV urban buses where the required range is around 150 km. The produced netback results are in Table 3. In general, the economic prospects appear to be poor in the short-term as none of the CPs exhibit positive produced hydrogen netbacks today. However, with cost declines, improved fuel efficiency, and lower distribution costs, we see positive netbacks across the CPs by 2030, many of which are above the indicative renewable hydrogen production cost of €2.4/kg (Annex A1).

Table 3 Produced hydrogen and electricity netbacks for FCEV (liquid trucking distribution) and BEV urban buses by Contracting Party

	FCEV (€/kg / €/kWh)		BEV (€/kWh)	
Contracting Party	**Today**	**2030**	**Today**	**2030**
Albania	-2.5 / -0.07	**3.7 / 0.11**	0.09	0.25
Bosnia & Herzegovina	-2.8 / -0.08	**2.7 / 0.08**	0.04	0.19
Georgia	-4.4 / -0.13	1.0 / 0.03	-0.04	0.09
Moldova	-3.9 / -0.12	1.5 / 0.04	-0.02	0.12
Montenegro	-2.4 / -0.07	**3.1 / 0.09**	0.06	0.22
North Macedonia	-3.0 / -0.09	2.4 / 0.07	0.03	0.18
Serbia	-1.4 / -0.04	**4.1 / 0.12**	0.11	0.28
Ukraine	-3.8 / -0.11	1.6 / 0.05	-0.01	0.13
Kosovo*	-2.5 / -0.08	**3.0 / 0.09**	0.05	0.21
Indicative production cost (€/kg)	**Today**	**2030**		
Renewable hydrogen	5.1	2.4		
Low-carbon hydrogen	1.8	1.6		

Source: Consultant analysis. Prices in **bold** reflect if the produced hydrogen netback is above the *indicative* renewable hydrogen production cost. For reference, add €5.4/kg for today and €1.8/kg for 2030 to arrive at the *total* delivered hydrogen netback price, including distribution, storage, and fuelling station costs. Indicative production costs reflect 'average' resources, as per the forecast in Annex A1, but note that production costs will vary widely by location in practice.

In contrast, while some of the BEV netbacks are negative today, with Albania and Serbia being notable exceptions, all the CPs exhibit relatively high electricity netbacks in the future as the cost of BEV buses declines.

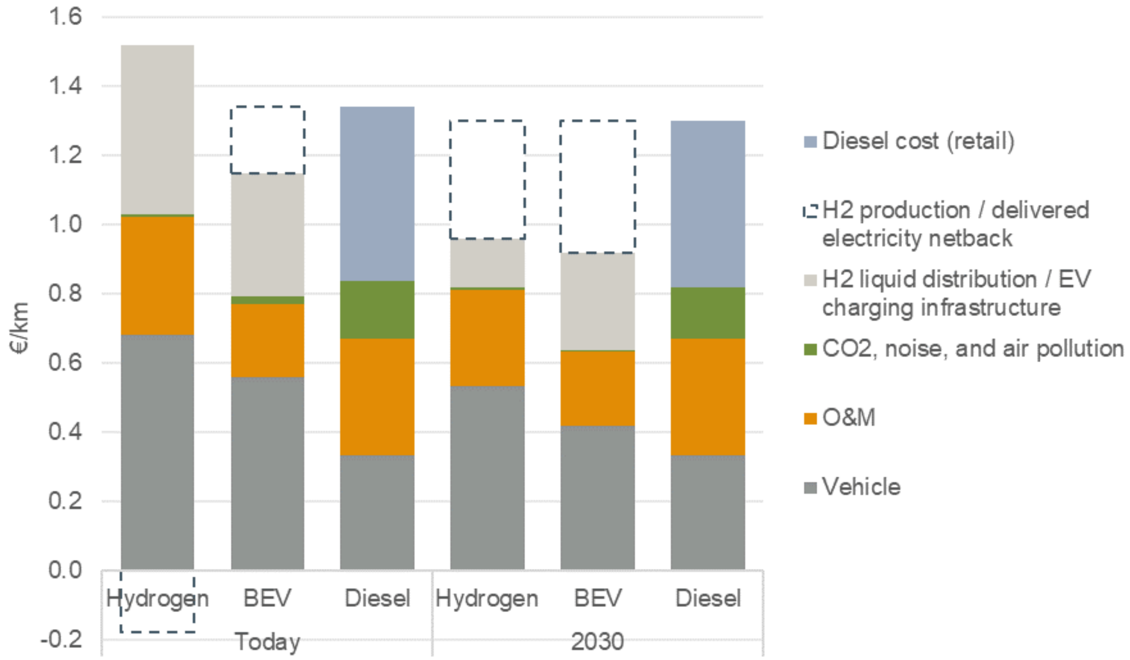
These contrasting results are due to a combination of hydrogen buses continuing to have significantly higher capital costs than diesel buses and having a lower fuel efficiency advantage over diesel buses compared to the trucking case.

Using Serbia's high diesel prices as the illustrative example again given the calculations for all the CPs above in Table 3, Figure 3 presents the stack of total ownership costs and illustrates the required netback prices. Cost reductions in hydrogen distribution are the primary factor in

[22] Hydrogen Council, Path to hydrogen competitiveness: A cost perspective, 20 January 2020, Exhibit 21.

achieving positive produced hydrogen netbacks in the future, as opposed to the negative value today. In contrast, BEV buses have a positive netback today, improving further in the future.

Figure 3 FCEV and BEV urban bus netback calculations per km for Serbia



Source: Consultant analysis.

2.4 Conclusions

Our analysis is generally pessimistic about the short-term prospects for hydrogen transport in the CPs as it is apparent that hydrogen would struggle to be cost competitive with diesel trucks and buses. While pilot studies are ongoing in some Western European countries, these are more competitive today given higher taxes on diesel, which brings diesel prices more in line with those reported for Albania and Serbia today.[23] BEVs also present a challenge as a competitor for decarbonising transport, particularly outside of long distance routes.

For CPs with relatively high diesel prices today (Albania and Serbia), feasibility and pilot studies for long-haul hydrogen trucking or buses, perhaps supplied by flexible, small-scale gaseous trucks or liquid trucking for longer distances, could be a near term consideration given diesel transport costs are already high.[24] As the netback analyses suggest, there may be long-run potential to significantly reduce costs in the future and achieve decarbonisation goals.

[23] Belgium, France, Germany, the Netherlands, and the UK all report diesel prices greater than €1.2/l today.
[24] Albania may also be particularly well-placed to produce renewable hydrogen given its significant hydropower capacity.

Achieving the projected figures in Table 1 for 2030 across all hydrogen transport will require a dramatic scale-up of refuelling infrastructure at significant cost.[25] However, the Hydrogen Council attributes about 55% of the potential cost decline in fuelling stations to increased utilisation and station size. Both of these can be achieved along dedicated FCEV transport routes, where refuelling needs are predictable and high volume. This will require the CPs to coordinate refuelling infrastructure along heavy traffic routes.[26] Hence, the projected figures for 2030 may be achievable in the near term for pilot FCEV truck projects along dedicated routes, particularly along routes where overhead catenary infrastructure may be impractical.

The economics of FCEV urban buses is less optimistic, as BEV urban buses may hold an inherent cost advantage. However, if high diesel cost CPs such as Albania and Serbia manage successful hydrogen trucking pilots, following the lead of ongoing programmes by Toyota in California[27] or Hyundai in Switzerland[28], there could be economies of scale benefits if both trucking and buses are converted to hydrogen in these two CPs.

There appears to be less of a case for CPs with lower cost diesel to engage in pilot studies for hydrogen transport. An ongoing hydrogen transport feasibility study in Ukraine, with a reported diesel price of €0.7/l, has concluded that the large capex associated with the initial infrastructure requirements make the transport sector less attractive as an initial market for hydrogen.[29] We understand there is also an ongoing project looking at hydrogen buses in Georgia,[30] but there are no findings to date that can inform this discussion.

[25] The IEA (2019) estimates that 400 refuelling stations would be required to serve a fleet of 1 million FCEVs at a cost of €0.4-0.5 billion.
[26] For example, SEETO identifies "Route 7" as a high-traffic route for southeast Europe (7,582 annual average daily traffic, 13% of which being HGVs), which runs from Lezhe in Albania through Pristina in Kosovo* to Doljevac/Nis in Serbia.
[27] https://fuelcelltrucks.eu/project/kenworth-10-hydrogen-fuel-cell-truck-in-cooperation-with-toyota/
[28] https://hyundai-hm.com/en/
[29] Consultant interviews with Ukrainian stakeholders.
[30] Consultant interviews with Georgian stakeholders.

3 Industrial applications

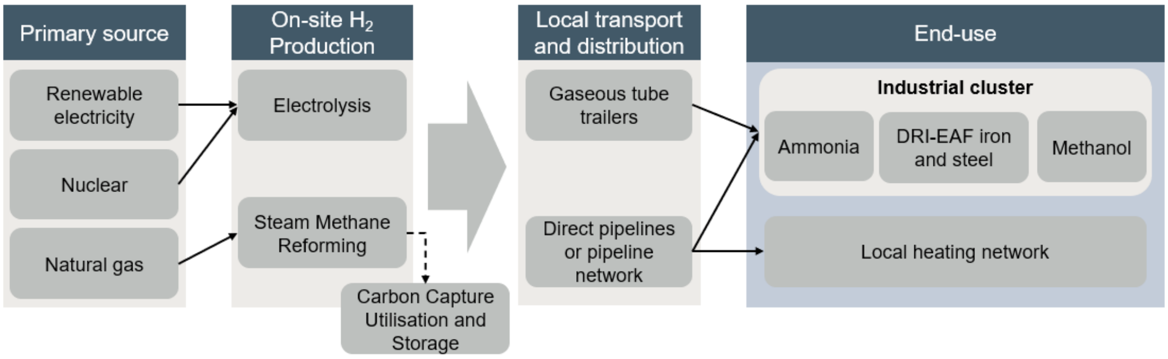
Renewable/low carbon hydrogen has been proposed as a decarbonisation option for several industrial applications where electrification may prove difficult (e.g., high heat applications) or where dedicated hydrogen, mostly produced from steam methane reforming (SMR) of natural gas or coal gasification, already serves as a feedstock.

We focus on the following key industrial applications - ammonia, iron and steel, and methanol, as these have a high decarbonisation value or potential, and are significant industries in at least some of the CPs. For each application we compare projections of production costs when using the following hydrogen production technologies:

- Electrolysers powered by zero carbon electricity (*Electrolyser);*
- Natural gas SMR without Carbon Capture Utilisation and Storage (CCUS) (*NG);*
- Natural gas SMR with CCUS (*NG + CCUS*) or coal gasification with CCUS (*Coal + CCUS);*
- Coal gasification without CCUS (*Coal*)[31].

For CPs that currently have gas networks, natural gas-based production may be considered the appropriate counterfactual relative to hydrogen. For CPs without gas networks, coal-based production (whether with imported or domestically produced coal) may be the relevant counterfactual. We do not consider the case of greenfield gas/ hydrogen pipeline network development. We assume that hydrogen produced from electrolysers is produced on-site, but this requires sufficient scale to justify the electrolyser investment and to ensure its high utilisation, which may require the development of industrial hydrogen clusters. An example of the hydrogen supply chain for a potential industrial cluster (with an attached localised heating network) is illustrated in Figure 4.

Figure 4 Hydrogen supply chain for an illustrative industrial cluster



Source: ECA

We first present cost estimates under a "base case" projection up to 2050, comparing electrolyser-, natural gas-, and coal-based (with and without CCUS) production technologies under a fixed set of assumptions (Table 4), which is then supplemented by conducting

[31] Hydrogen produced from unabated coal gasification is practically non-existent in Europe today, but we include its costs for completeness.

sensitivity analysis. We initially assume that electricity is supplied at zero carbon cost, i.e., a future with an emissions-free grid, but we consider a carbon-emitting grid in our sensitivity scenarios and the potential for combining dedicated plants using renewable energy sources (RES) with flexible electrolysers and plant production.

Table 4 Base case input assumptions

Input	Unit	Assumption
Rate of return	%	8%
Plant lifetime	Years	25
Electricity price	€/kWh	0.08
Natural gas price	€/kWh	0.03
Coal price	€/t	50
Carbon price	€/tCO_2	40
CCUS variable cost	€/tCO_2	17

Source: Consultant assumptions.

In addition to applying an assumed carbon price of €40/tCO_2, we assume a CCUS variable cost of \$20/tCO_2 (€17/tCO_2).[32] In our sensitivity analysis, we report the carbon costs required for electrolyser-based production to reach cost parity with unabated natural gas- or coal-based production.

For electrolyser-based production, the electricity input price for the electrolyser is the key variable. Hence, for each CP, the relevant question may be whether electricity grid tariffs can be low enough (and the grid zero carbon) to make electrolyser-based production competitive *or,* if supplied by a dedicated RES plant, whether the electrolyser and plant production are flexible enough to take advantage of recent declines in low variable cost (and intermittent) RES.

There is a trade-off for electrolysers in being supplied by firm grid electricity, incurring transmission and distribution (T+D) costs, and having the same carbon intensity as the grid versus being supplied by low variable cost carbon-free RES and avoiding T+D costs; however, in the latter case, the electrolyser and, production at the plant, will need to operate flexibly with intermittent electricity supply (reducing plant utilisation), and there may also be a need to invest in significant on-site hydrogen storage. As part of our sensitivity analysis, we consider recent modelling studies looking at the potential for further cost reductions by relying on a combination of flexible plant production and supplying electrolysers with intermittent, low variable cost RES electricity.

[32] This is a common cost assumption in recent IEA modelling. For example, see its Energy Technology Perspectives 2020 report. With a carbon price of €40/tCO_2 and a CCUS cost of €17/tCO_2, installing CCUS technology that captures 90% of emissions effectively halves the cost of CO_2 relative to if emissions were unabated.

3.1 Ammonia

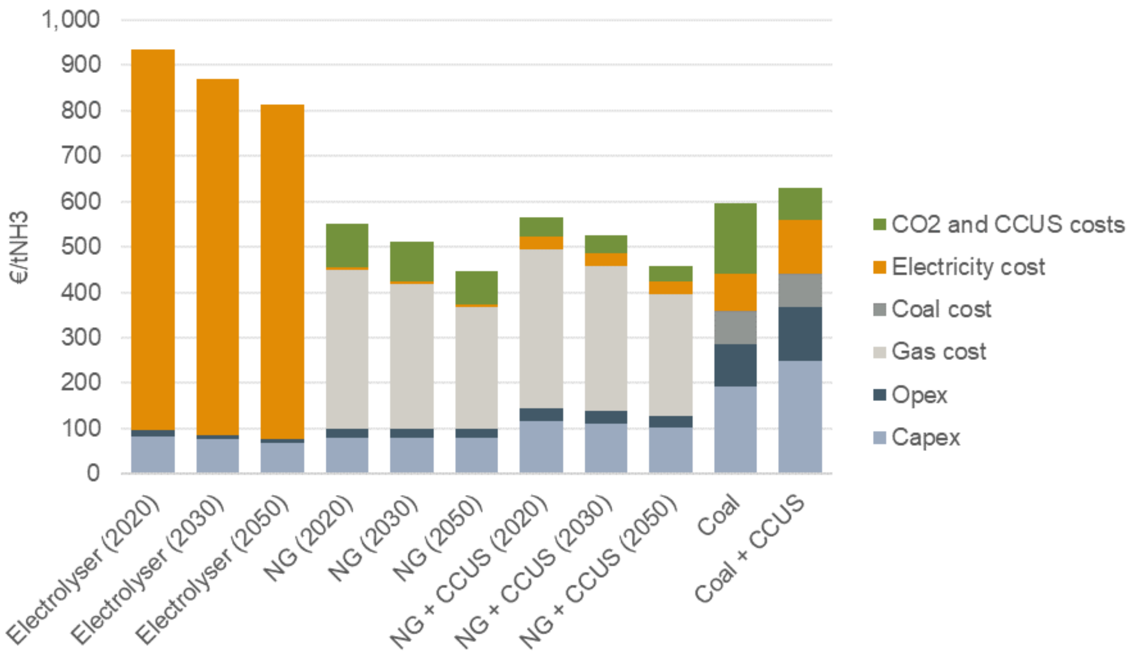
Ammonia (NH_3) is the world's second-largest source of hydrogen demand today and its production requires a significant feedstock of dedicated hydrogen. Ammonia is mostly used in the manufacture of fertilisers such as urea[33] and ammonium nitrate, as well as explosives and synthetic fibres. Most hydrogen produced for ammonia is sourced from natural gas SMR today, except in Asia where hydrogen from coal gasification is more prominent.[34] It is understood that ammonia production, outside of significant production in Ukraine[35], is currently at a low level across the CPs.

3.1.1 Base case costs

Figure 5 presents a base case comparison of the production costs of ammonia for 2020 to 2050 where the hydrogen is produced by either an electrolyser, natural gas, natural gas + CCUS, coal, or coal + CCUS based technologies. While improved electrolyser efficiency and lower capex as electrolyser production scales up are expected to reduce electrolyser-based production costs by about 13%, it is still not projected to be cost competitive with natural gas- or coal-based production methods, even after including CO_2 and CCUS costs. It is also clear that electricity costs are *the* key factor for electrolyser-based production due to the high electricity requirements of electrolysers. Expected improvements in the efficiency of natural gas SMR for ammonia production is an additional challenge to electrolyser-based production's long-run competitiveness.

[33] Note that urea also requires CO_2 as a feedstock, which is subsequently released after its application. Hence, urea fertiliser is not carbon-free even if its hydrogen feedstock is zero carbon without offsetting its CO_2 emissions elsewhere.
[34] IEA, 2019, The Future of Hydrogen, Figure 38.
[35] Ammonia/fertilizer production in Ukraine is largely unified under the Ostchem holding company, which includes Azot PJSC, Concern Sitrol PJSC, Severodonetsk Azot Association PrJSC, and Rivne Azot PJSC.

Figure 5 Ammonia production cost projections by technology, 2020-50



Source: Consultant analysis.

3.1.2 Sensitivities

Electrolysers with dedicated RES

We present the results of our key sensitivities in Figure 6 below. We contrast the costs of electrolysers supplied by the grid (now adding an assumed carbon cost from a carbon-emitting grid) versus being supplied by low variable cost, zero carbon RES. Modelling by Armijo and Philibert (2020) suggests that a combination of optimising wind and solar production with an on-site electrolyser and plant production flexibility can potentially lower production costs despite higher capex requirements.[36] This is due to electricity costs being such a key determinant of electrolyser-based production costs. Following the Armijo and Philibert (2020) analysis, for the 'hydrogen (dedicated RES)' case, we assume:

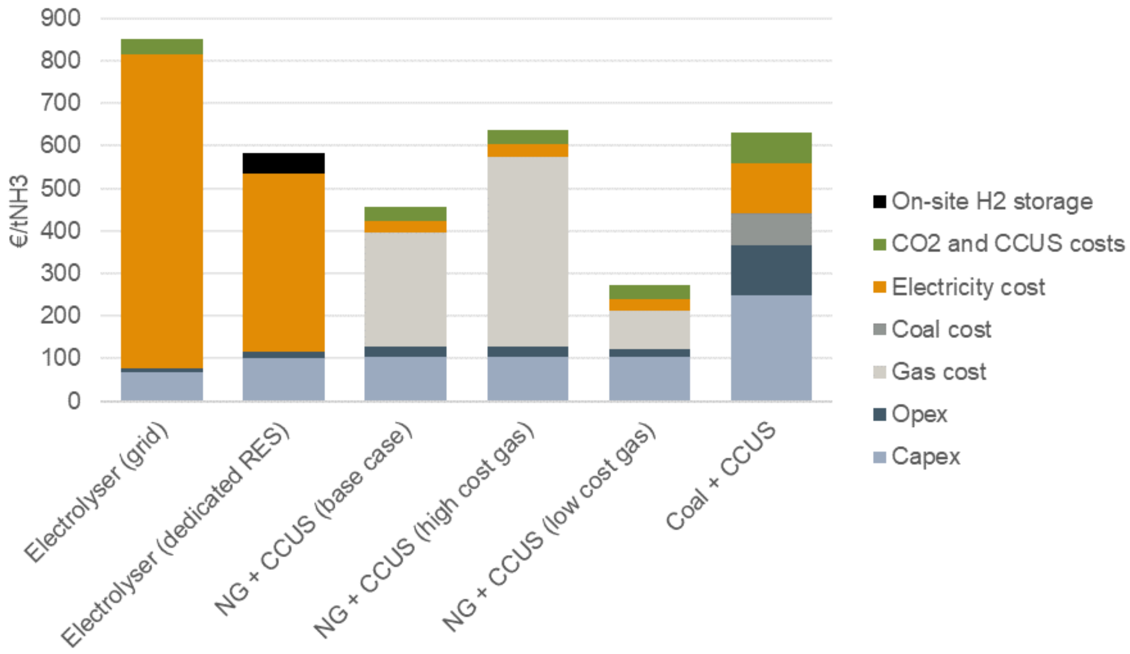
- A 50% uplift to capex and opex to account for an oversized Haber-Bosch[37] plant and the cost of dedicated RES facilities;
- A variable electricity cost of €0.04/kWh from the dedicated RES plus a "firm-up" electricity option (such as an on-site battery) that is relied upon for 5% of electricity needs at a cost of €0.15/kWh; and

[36] Armijo J. and C. Philibert, 2020, 'Flexible production of green hydrogen and ammonia from variable solar and wind energy: Case study of Chile and Argentina', *International Journal of Hydrogen Energy*, 45 (3), 1541-1558.
[37] The Haber-Bosch process, which converts hydrogen and nitrogen to ammonia, is the main industrial procedure for producing ammonia.

- We assume that the requirement for on-site hydrogen storage adds €50/t of ammonia (NH_3) to production costs.[38]

This scenario brings electrolyser-based production within cost competitiveness of coal-based and high-price natural gas-based production (with CCUS). However, we see that if a CP has less costly gas available (€0.01-0.03/kWh), RES-based hydrogen will still struggle to be economically competitive (assuming CCUS for fossil fuel-based production can reach scale).

Figure 6 Ammonia production cost sensitivities (2050)



Source: Consultant analysis. High-cost gas is €0.05/kWh, low-cost gas is €0.01/kWh.

Carbon price

Given the assumption that CCUS technology achieves scale and is 90% effective, the results are not materially sensitive to different carbon price levels. However, if we were to compare the projection of electrolyser-based production costs in 2050 to natural gas- or coal-based production with unabated CO_2 emissions for our base case in Figure 5:

- A €245/tCO_2 carbon price would be required for electrolyser-based production to be competitive with natural gas-based ammonia production or €115/tCO_2 if low-variable cost dedicated RES electrolyser-based production is an option; and

- A €95/tCO_2 carbon price would be required for electrolyser-based production to be competitive with coal-based production or €40/tCO_2, i.e. our base case carbon price, if low variable cost dedicated RES electrolyser-based production is an option.

[38] Armijo and Philibert (2020)'s modelling suggests this additional cost could range from €10-200/tNH_3 depending on the achievable level of production flexibility, the required sizing of the hydrogen storage, and if low-cost geological storage is available or not.

These contrast with the IEA's 'Sustainable Development' carbon price projection of €106-119/tCO_2 by 2040 or the EU's 'Stated Policies' carbon price of €44/tCO_2 by 2040, or BP's 'Rapid' carbon price projection of €148-212/ tCO_2 or its 'business-as-usual' projection of €33-56/tCO_2 (see Annex A3).

3.1.3 Key inferences

In general, it is apparent that electrolyser-based production is higher cost than production from fossil fuels, even after accounting for the costs of CCUS. The sensitivity analysis in Figure 6 highlights that even if low-cost RES electricity can be utilised to lower costs, CPs with existing low-medium cost gas supply, such as Ukraine (which is currently an ammonia exporter), are still unlikely to find electrolyser-based ammonia production to be economically competitive.

This is dependent on CCUS technology effectively scaling up for low carbon hydrogen production, but it would still require very high carbon prices of over €200/tCO_2 for electrolyser-based production to be economically competitive with unabated natural gas-based production. However, for CPs currently engaging in coal-based ammonia production (if any) and without access to natural gas supply, a combination of electrolysers with dedicated RES and/or carbon prices could make electrolyser-based ammonia production economically competitive in the coming decades.

3.2 Iron and steel

The two main primary production routes for iron and steel are:[39]

- **Blast furnace-basic oxygen furnace (BF-BOF)**, where hydrogen is a by-product of coal use, and accounts for 90% of global primary steel production; and
- **Direct reduction iron-electric arc furnace (DRI-EAF)**, which uses hydrogen and carbon monoxide as a reducing agent, with the hydrogen produced from dedicated facilities, mostly using SMR, rather than as a by-product. DRI-EAF is particularly prominent in regions with low natural gas prices or low coal prices.

Given the need for dedicated hydrogen production in the DRI-EAF primary production route, it is a major potential source for scaling up hydrogen production in the future, as well as reducing the carbon intensity of the steel industry if renewable or low carbon hydrogen can be utilised.

[39] IEA, 2019, The Future of Hydrogen, 108-109. 'Secondary' iron and steel production involves the re-melting of steel scrap in an EAF.

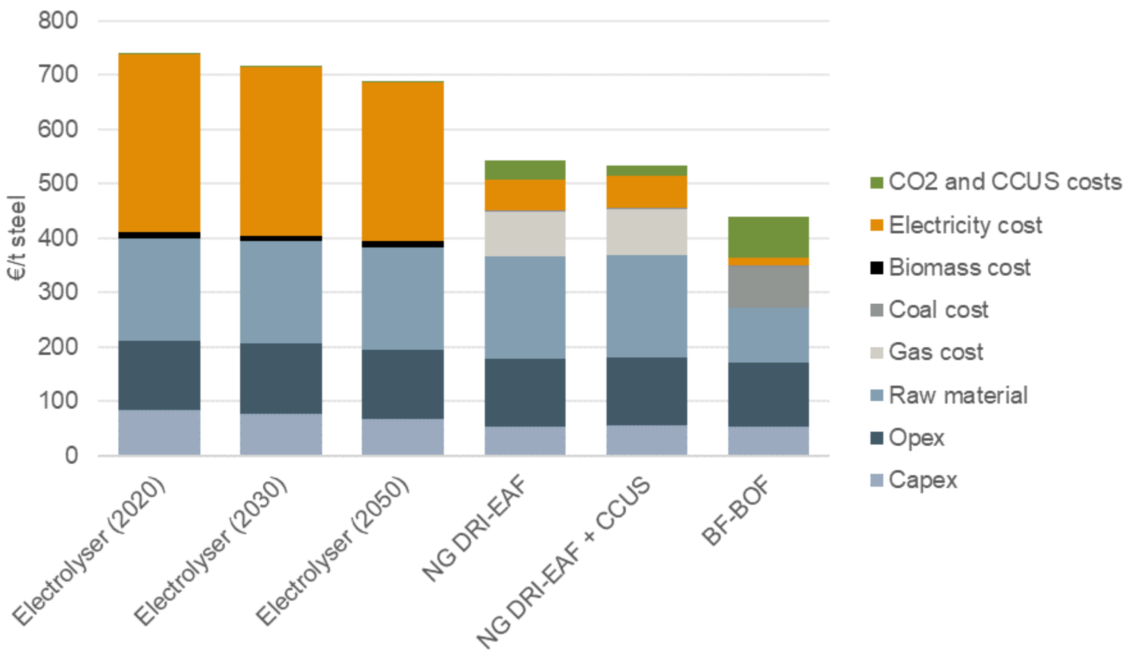
Across the CPs, steel making is most prominent in Ukraine, where coal-based production is most common[40]. In Albania[41], Kosovo*, North Macedonia[42], Montenegro[43], Serbia[44], and Bosnia and Herzegovina[45], steel production is also largely dependent on highly carbon-intensive coal-based production., although this could change with ongoing gas network developments.

3.2.1 Base case costs

We compare the projected costs of electrolyser-based DRI-EAF (with biomass also replacing coking coal) with the cost of natural gas-based DRI-EAF production and coal-based BF-BOF in Figure 7. Lower capital expenditure (capex) and improved efficiency are projected to lower electrolyser-based production costs by only 7% by 2050, which is not sufficient to bridge the gap with natural gas or coal-based production. It is apparent that electricity costs comprise a lower share of iron and steel production costs relative to the ammonia case as operating expenditure (opex) and raw material costs are significant cost components. BF-BOF has the lowest production costs, but it is also highly emitting at 1.9 tCO_2 per tonne of steel, which adds €76 per tonne of steel when applying a €40/tCO_2 carbon price.

[40] Ukraine's most prominent producer is global steel producer ArcelorMittal's Kryvyi Rih plant, which produced 4.8 million tonnes of steel in 2018. Despite Ukraine's significant natural gas supply, natural gas-fired electric arc furnaces only make up 7% of Ukrainian steel due to low domestic demand for the semi-finished production of EAF and a shortage of scrap. The largest EAF plant is Interpipe Steel (Dniprosteel), with a capacity of 1.3 million tonnes.
[41] Albania's primary steel producer is the Kurum Iron-Steel Plant.
[42] Our understanding is the steel industries in Kosovo* and North Macedonia are more centred around steel processing and fabrication rather than raw steel production. See: https://www.see-industry.com/en/metal-processing-industry-in-kosovo/2/812/ and https://www.see-industry.com/en/macedonian-steel-and-metal-manufacturing/2/1493/
[43] Seethe Tosçelik Nikšić steel plant, recently purchased by the Turkish Tosyali Holding company.
[44] Almost all steel production in Serbia is by HBIS Serbia, which has the capacity to produce up to 2.2 million tonnes of finished products per year and includes a plant in Smederevo with two blast furnaces.
[45] Global steel producer ArcelorMittal has a BOF steel plant in Zenica: https://barsandrods.arcelormittal.com/mills/zenica

Figure 7 Electrolyser-based iron and steel production cost projection (2020-50) compared to prevailing technologies and CCUS



Source: Consultant analysis

3.2.2 Sensitivities

Electrolysers with dedicated RES

Combining an electrolyser with intermittent RES can take advantage of recent RES cost declines and ensure that the hydrogen is produced carbon-free. However, this also implies flexible operation is required to manage RES intermittency, which will raise investment costs. For example, recent modelling of a hydrogen-based DRI-EAF process assumed a capacity cost of €574 per tonne of capacity,[46] while that study refers to another study that assumes the electrolyser mainly operates during times of inexpensive electricity prices, meaning fewer operating hours and the need for hydrogen storage, raising capex to €874 per tonne of capacity.[47] A 50% increase in associated capex is significant but given electricity costs are the dominant factor in hydrogen-based production costs, this cost increase may be outweighed by any resulting decline in electricity costs.

Modelling by the IEA of hydrogen-based steel production in India via dedicated RES suggests this can reduce overall costs.[48] Lower utilisation, plant oversizing, curtailed electricity, and the requirement for hydrogen storage increase capex, but this is more than offset by reduced fuel costs if hydrogen can be supplied at a levelised cost of €1.4-1.8/kg. The cost of hydrogen-

[46] Vogl, V. et al., 2018, 'Assessment of hydrogen direct reduction for fossil-free steelmaking', *Journal of Cleaner Production*, 203, December, 736-745.
[47] Fischedick, M. et al., Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change.
[48] IEA, Iron and Steel Technology Roadmap 2020, Box 3.2.

based steel production from the grid ranges from €425-730 per tonne at a grid electricity cost range of €25-90/MWh. This compares to an approximate range of €425-470 per tonne for 100% variable renewable energy (VRE)-supplied iron and steel production. Costs can be further reduced to €400-425 per tonne if low-cost geological storage is available.[49]

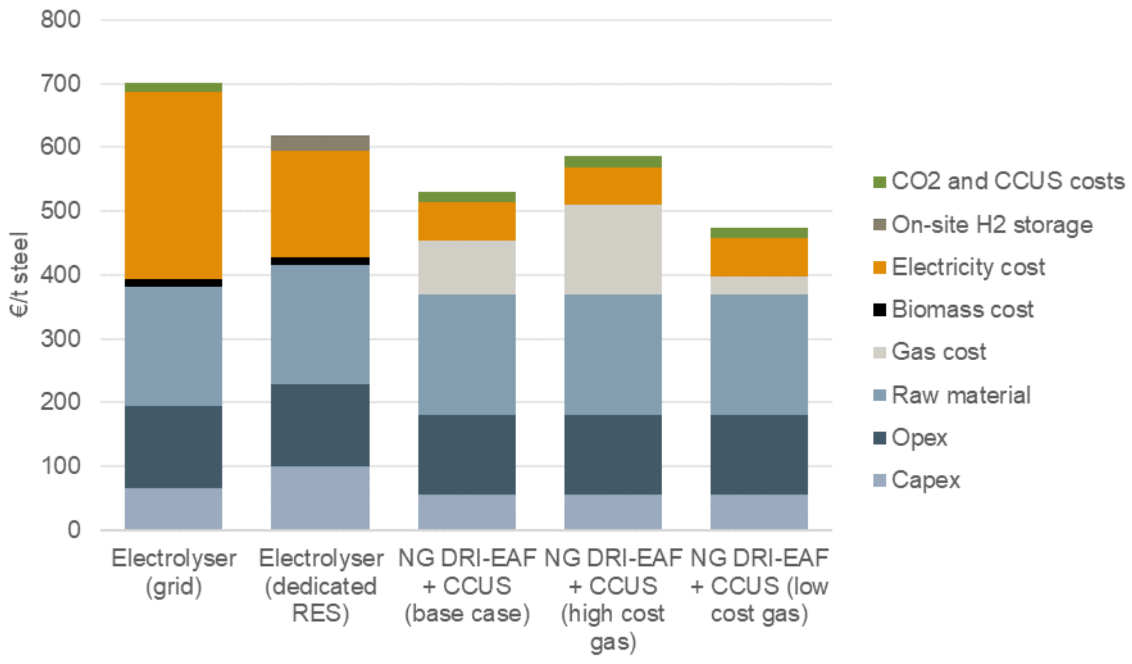
As an illustrative exercise, we follow the methodology of the IEA (2020) and Armijo and Philibert (2020) to compare the flexible, dedicated RES production case to natural gas DRI-EAF with CCUS at high and low gas prices in Figure 6. For the 'hydrogen (dedicated RES)' case, we assume:

- A 50% uplift to capex to account for plant oversizing and the cost of dedicated RES facilities;
- A variable electricity cost of €0.04/kWh from the dedicated RES plus a firm-up electricity option (such as an on-site battery) that is relied upon for 5% of electricity needs and costs €0.15/kWh; and
- That the requirement for on-site hydrogen storage adds €25/t to production costs.[50]

These factors combine to reduce production costs relative to the grid electricity case by 12%, nearly bringing the cost into line with the high-cost natural gas DRI-EAF CCUS case. However, it remains significantly higher cost than the low and base case natural gas cost scenarios. This modelling suggests that the exploitation of low variable cost RES can lower costs for electrolyser-based iron and steel production, but given capex, opex, and raw materials make up a significant share of steel production costs, lowering energy input costs has a smaller impact relative to the case of ammonia production.

[49] The IEA assumes an RES supply mix of $20/MWh solar and $30/MWh wind. At the high-cost end, tank-based hydrogen storage is assumed with a capex of $15/kWh versus $0.4/kWh for lower-cost geological storage.
[50] IEA (2020) modelling suggests this additional cost could be minimal if low-cost geological storage is available.

Figure 8 Iron and steel production cost sensitivities (2050)



Source: Consultant analysis.

Carbon price

Given the assumption that CCUS technology achieves scale and is 90% effective, the results are not materially sensitive to different carbon price levels. However, if we were to compare the base case projection of electrolyser-based production costs in 2050 to natural gas- or coal-based production with unabated CO_2 emissions:

- A €210/tCO_2 carbon price would be required for electrolyser-based production to be competitive with unabated natural gas-based iron and steel production or €125/tCO_2 if low-variable cost dedicated RES electrolyser-based production is an option; and

- A €160/tCO_2 carbon price would be required for electrolyser-based production to be competitive with unabated coal-based iron and steel production or €135/tCO_2 if low-variable cost dedicated RES electrolyser-based production is an option.

These contrast with the IEA's 'Sustainable Development' carbon price projection of €106-119/tCO_2 by 2040 or the EU's 'Stated Policies' carbon price of €44/tCO_2 by 2040, or BP's 'Rapid' carbon price projection of €148-212/ tCO_2 or its 'business-as-usual' projection of €33-56/tCO_2 (see Annex A3).

3.2.3 Key inferences

Iron and steel production is prominent across the CPs, particularly in Ukraine, but there is currently no coordinated planning for developing renewable or low carbon hydrogen production for DRI-EAF steel production. The analysis shows that electrolyser-based production will be higher cost than natural gas-based production. Significant carbon prices would be required to make electrolyser-based production equal cost to unabated fossil fuel-based production. The exploitation of low-cost variable RES may further reduce the cost of electrolyser-based production, but the analysis suggests this will still not bridge the gap with carbon-emitting steel production. However, there are numerous ongoing studies for producing low-emissions steel. The IEA details nine different pilot projects and feasibility studies looking into processes for CO_2 avoidance or management in the steel industry.[51] CPs with steel industries should monitor these developments, particularly as they seek to align their economies with EU environmental regulations, which are likely to drive continued interest in low-emissions steel production.

3.3 Methanol

Methanol (CH_3OH, often abbreviated as MeOH) is the world's third-largest source of hydrogen demand today and its production requires a significant feedstock of dedicated hydrogen. The majority of the hydrogen produced for methanol comes from natural gas, except in Asia where coal-based production is more prominent due to high gas prices.[52]

Methanol is widely used in the chemical industry as a starting material, reactant, or as a fuel itself. The main products obtained from methanol are formaldehyde (the end use of 1/3 of global methanol production), methyl methacrylate and acetic acid. Increased attention is also being paid to the development of methanol-to-olefins and methanol-to-aromatics, which open a route to producing high-value chemicals from methanol, and thus plastics.

Within the CPs, 190,000 tonnes per year of methanol is currently produced by the Severodonetsk Azot Association PRJSC[53], under the Ostchem Holding company in Ukraine, which is a holding group for a number of Ukrainian chemical producers, and MSK a.d. Kikinda in Serbia, which can produce up to 200,000 tonnes per year.[54]

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[51] See IEA, 2019, The Future of Hydrogen, Box 10:
1) the HYBRIT joint venture in Sweden is exploring the feasibility of hydrogen-based steelmaking using a modified DRI-EAF process design.
2) the SALCOS project is looking to partially implement hydrogen-based iron reduction, gradually increasing the proportion of hydrogen.
3) the GrInHy and H_2FUTURE initiatives to scale-up electrolyser designs for steel production, in collaboration with the Austrian utility VERBUND.
4) the Σiderwin and Boston Metal projects look to use electricity directly for reduction, *avoiding* the need for hydrogen.
5) Japanese researchers are looking into ammonia-based steel production.
6) HIsarna is a project looking into equipping CCUS and upgrading the smelt reduction process to negate the need for coke ovens and the agglomeration process.
7) Al Reyadah in Abu Dhabi is developing a commercial-scale DRI-EAF plant with CCUS.
8) Projects such as Carbon2Chem and Steelanol are looking to utilise the H2, CO, and CO2 from Works-Arising Gas (WAG) in the BF-BOF process.
9) the COURSE 50 project in Japan is looking to raise the proportion of hydrogen used as the reduction agent in the BF-BOF process.

[52] IEA, 2019, The Future of Hydrogen, Figure 38.

[53] PrJSC "Severodonetsk Azot Association".

[54] MSK a.d. Kikinda.

Electrolyser-based methanol production has the added benefit that it can serve as the utilisation endpoint for captured CO_2 as methanol also requires CO_2 as a feedstock for its production in the absence of fossil fuel-based production.[55]

3.3.1 Base case

Improved electrolyser efficiency and reduced capex see the production cost of electrolyser-based methanol fall by 18% by 2050. However, cost reductions are also expected across fossil fuel-based production methods due to increased energy efficiency and lower CCUS capex, limiting how much electrolyser-based production may actually “catch up”. The calculated cost of electrolyser-based production is also well above current market prices for methanol of €390/t of methanol (MeOH).[56] The modelled costs for natural gas-based production with CCUS are only marginally higher than unabated natural gas-based production. This aligns with Collodi et al. (2017), which found that upgrading a methanol plant with a CCUS unit would only increase capex by 20% and operational costs by 5%.[57] Coal-based production is well below market costs if the €40/tCO_2 carbon price is not applied, while adding a CCUS unit increases costs by 10-15%.

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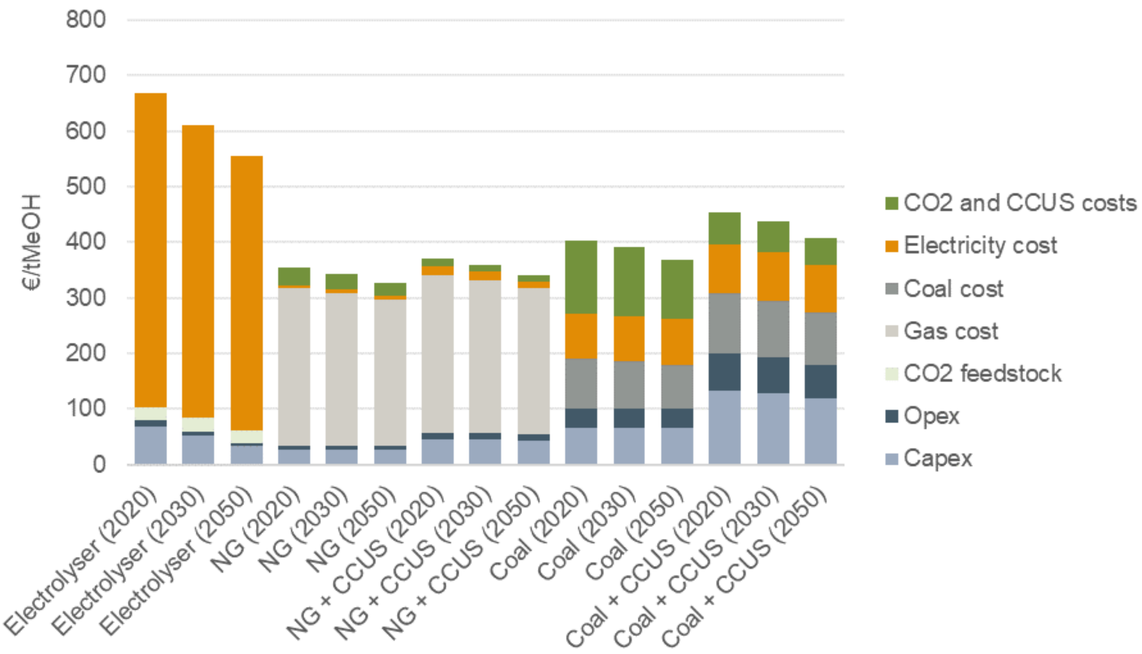
[55] For methanol to be carbon-free, it will need to subsequently sequester its embedded CO_2 or source CO_2 from direct air capture (DAC). We assume in our calculations that electrolyser-based methanol’s CO_2 feedstock is supplied at the same cost as our assumed cost of CCUS: €17/tCO_2. Other modelling has suggested that at a base case CO_2 price of €300/t, when sourced from DAC, and an electricity price of €0.07/kWh, methanol’s production cost would rise above €1,100/t. (Bos, M.J., et al, 2020, ‘Wind power to methanol: Renewable methanol production using electricity, electrolysis of water and CO_2 air capture’, *Applied Energy*, 264, 111672).

[56] https://www.methanex.com/our-business/pricing Value for 1 Jan – 31 Mar 2021 contracts.

[57] Collodi, G. et al, 2017, ‘Demonstrating large scale industrial CCS through CCU – a case study for methanol production’, *Energy Procedia*, 114, 122-138.

Figure 9 Methanol production cost projections by technology, 2020-50



Source: Consultant analysis. The cost of CO_2 feedstock is set at the same cost as CCUS (€17/tCO_2) and an assumed CO_2 input rate of 1.41 tCO_2/tMeOH.[58]

Across the different technologies, it is apparent that methanol's production costs are highly dependent on underlying fuel costs: 89% of the cost of electrolyser-based production is attributed to electricity costs; 81% of the cost of natural gas with CCUS production is attributed to natural gas and electricity costs.

3.3.2 Sensitivities

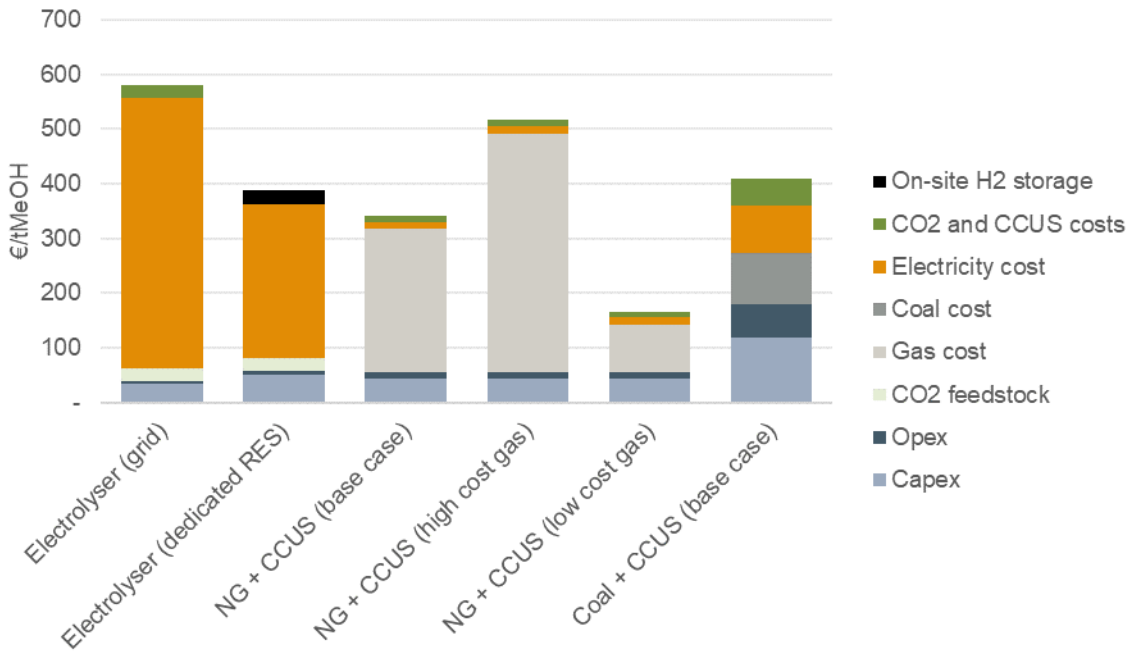
Electrolysers with dedicated RES

Given the production cost of every methanol production technology is highly dependent on input fuel costs, the electricity input price will determine the competitiveness of electrolyser-based production. As an illustrative exercise, we consider what electrolyser-based production could cost if supplied by 100% intermittent RES. We scale up capex and opex by 50%, assume an electricity input price of €0.04/kWh, as well as a "firm-up" electricity option, such as an on-site battery, providing 5% of electricity needs at a cost of €0.15/kWh, and we assume that the need for on-site hydrogen storage adds €25/tMeOH to production costs.

We compare this to our high (€0.05/kWh) and low (€0.01/kWh) natural gas price scenarios and our previous base case scenario for electrolyser-based production, which now includes the costs of a carbon-emitting grid, in Figure 10.

[58] Szima S. and C-C Cormos, 2018, 'Improving methanol synthesis from carbon-free H_2 and captured CO_2: A techno-economic and environmental evaluation', *Journal of CO_2 Utilization*, 24, 555-563, Table 5.

Figure 10 Methanol cost sensitivities (2050)



Source: Consultant analysis.

By lowering the assumed input electricity price, electrolyser-based production is now within the cost range of coal-based production with CCUS and well below the high gas price case. However, it is still 15% higher than natural gas-based production at the base case gas price. Natural gas-based production is similarly highly sensitive to its fuel price, with the low gas price case being less than half the cost of the electrolyser with dedicated RES scenario.

Carbon price

Given the assumption that CCUS technology achieves scale and is 90% effective, the results are not materially sensitive to different carbon price levels. However, if we were to compare the projection of electrolyser-based production costs in 2050 to natural gas or coal-based production with unabated CO_2 emissions:

- A €420/tCO_2 carbon price would be required for electrolyser-based production to be competitive with unabated natural gas-based methanol production or €145/tCO_2 if low-variable cost dedicated RES electrolyser-based production is an option; and

- A €110/tCO_2 carbon price would be required for electrolyser-based production to be competitive with unabated coal-based methanol production or €50/tCO_2 if low-variable cost dedicated RES electrolyser-based production is an option.

These contrast with the IEA's 'Sustainable Development' carbon price projection of €106-119/tCO_2 by 2040 or the EU's 'Stated Policies' carbon price of €44/tCO_2 by 2040, or BP's 'Rapid' carbon price projection of €148-212/ tCO_2 or its 'business-as-usual' projection of €33-56/tCO_2 (see Annex A3).

3.3.3 Key inferences

For CPs with low-medium natural gas prices, electrolyser-based production is unlikely to be economically competitive in the near term. While the efficiency of the electrolysis-based method is expected to improve with time, its high energy consumption led a recent technology review to conclude that electrolysis-based methanol synthesis is "*not attractive because of the energy consumption needed for hydrogen manufacturing*".[59] There may be more potential for electrolysis-based production to displace coal-based methanol production through low variable cost RES and moderately high carbon prices, but, as far as we are aware, no such production exists across the CPs as coal-based methanol production almost exclusively occurs in Asia.

Electrolysis-based production is therefore only likely to be attractive in CPs with an abundance of low-cost RES, or, taking a longer view of the need for a decarbonised economy, if low carbon hydrogen production fails to sufficiently scale up.

3.4 High heat applications

Hydrogen has been proposed as a decarbonisation solution for high-temperature heat industrial applications. While electricity is already used to generate high-temperature heat, either directly (electric arc and induction furnaces for steel) or indirectly (driving electro-chemical reactions in aluminium smelting), there are larger-scale processes, such as steam crackers and cement kilns, where electrification will be more challenging.

However, even when assuming a hydrogen delivery cost of \$2.3-2.7/kg (€1.9-2.2/kg), modelling by the IEA suggests carbon prices of \$200/tCO_2 (€162) would likely still be needed for hydrogen to be cost competitive for providing high heat and that sustainable bioenergy may be the more cost effective decarbonisation option.[60]

Hydrogen may still have potential for "hard to reach" industries where CCUS proves impractical and retrofitted pipelines or small-scale on-site electrolysers are possible, or where sustainable bioenergy supply is limited. However, if hydrogen remains a "niche" fuel option, this will also undermine the need for scale to lower costs to make it viable across the economy.

3.4.1 Cement

While cement may be a potential high heat application for hydrogen, and there are cement factories across the CPs, such as Albania, there are several technical challenges to overcome before pilot projects can begin. The IEA summarises:[61]

- Hydrogen has high combustion velocity relative to carbon-containing fuels, and a non-luminous flame, making it difficult to optically monitor;

[59] Bozzano, G. and F. Manenti, 2016, 'Efficient methanol synthesis: Perspectives, technologies, and optimization strategies', *Progress in Energy and Combustion Science*, 56, 71-105.
[60] IEA, 2019, The Future of Hydrogen, Figure 49.
[61] IEA, 2019, The Future of Hydrogen, Box 11.

- Hydrogen flames achieve relatively low radiation heat transfer, so require other (carbon-free) "media" (such as clinker dust) to be introduced into the fuel stream:
    - There may be a need to redesign current burners to deal with the new media (clinker dust has abrasive properties);
- Hydrogen causes corrosion and brittleness for some metals, requiring new coatings and other protective measures;
- Intermittent hydrogen sources could impact users with "on-demand" processes, potentially requiring on-site storage; and
- Explosive properties make handling hydrogen on-site more difficult than traditional fuels - it may be safer to store as ammonia.

Recent modelling in the UK suggested that a carbon-free process that combines hydrogen and biomass would increase production costs per tonne of cement by £21.7 (€24).[62] With cement prices averaging around €60 per tonne,[63] this implies a 40% increase in prices. Hence, if hydrogen-based, zero carbon cement production is to be realised, it will likely require a significant combination of public funding/subsidy and carbon prices to be competitive with fossil fuel-based production. It is therefore unlikely that any of the CPs would be the appropriate location for pilot zero carbon cement projects.

Alternatively, modelling by the IEA suggests CCUS for cement production could become cost competitive at a CO_2 price of €65-105/tCO_2.[64] The IEA notes that multiple CCUS technologies for cement are in the demonstration/early adoption phase, while electrolyser-based cement is still at the conceptual stage.[65] This may then be a case where, if CCUS is proven at scale, it would be the more cost-effective decarbonisation pathway rather than adapting cement production to using hydrogen.

From the perspective of the CPs, the best option is likely to be to observe the success of hydrogen-based high heat pilot studies in other countries against the progress of achieving CCUS at scale. Simultaneously, CPs could also start to evaluate their supplies of sustainable biomass as a decarbonisation pathway for high heat purposes given there is some general pessimism about the economics of hydrogen-based cement production.

62 MPA, Cinar, and VDZ, 2019, 'Options for switching UK cement production sites to near zero CO_2 emission fuel: Technical and financial feasibility', Feasibility Study for BEIS.
63 European Commission, 2018, Competitiveness of the European Cement and Lime Sectors.
64 IEA, Energy Technology Perspectives 2020, 228-229.
65 IEA, Energy Technology Perspectives 2020, Table 4.3.

4 Power storage

Substantial cost reductions and a supportive policy environment have contributed to rapid growth in the deployment levels of VRE technologies (principally wind and solar PV) globally. Such growth is expected to continue as governments pursue national and international decarbonisation and renewable energy objectives. Furthermore, the increased electrification of heat and transport will add demand, requiring yet more renewable generation capacity.

As with variance in demand, VRE needs balancing capacity able to provide power at times of low generation. At present this is predominantly provided by fossil fuel or hydro power stations. However, to achieve long-term decarbonisation objectives, low or zero carbon options for balancing capacity are necessary. Advances in battery energy storage systems (BESS) have helped them become increasingly competitive at providing rapid short-term balancing, particularly in ancillary service markets. This is of particular importance as wind and solar PV are non-synchronously connected generation sources, meaning they do not contribute to inertia in the system, resulting in more rapid changes in system frequency levels following a fault. Through their ability to respond more rapidly than traditional primary reserve technology, BESS help mitigate this effect by arresting the fall in frequency at an earlier stage.

BESS are also being increasingly considered for intra-day arbitrage, storing excess generation at times of lower demand and/or higher RES output for use at times of scarce supply. Nevertheless, the economics of BESS deteriorate with longer duration storage (see results in Section 4.2 below), and hence current use is limited to intra-day storage cycles. There are also concerns regarding the ability of the supply chain for BESS, including the mining of raw materials necessary for production, to scale at the pace required for growing demand.

Hydrogen presents an alternative form of electricity storage. The technology has been proposed over multiple timeframes, from short-term ancillary services, up to longer-term seasonal storage[66]. In this section, we compare estimates for the cost of using hydrogen as a storage of power with other low and zero carbon technology options. We look at the levelised cost of energy (LCOE); a measure of the present value of the total cost, including all capital and operational costs, including carbon costs, of producing a unit of energy over the lifetime of a project.

LCOE is dependent on the amount of energy generated (related to the system's capacity factor) and will be strongly influenced by the generator's position in the merit order. Storage units seek to store energy at times of excess supply for discharge at times of scarce supply. They are therefore natural providers of peak supply. Traditionally, such plant would operate at annual capacity factors of no more than 10-15% by supplying during periods of peak demand (usually the evening and particularly in winter). With the increase in VRE, this pattern is changing. Low wind or solar generation during "shoulder" periods will require compensating through additional dispatch of peak and/or mid-merit flexible generators.

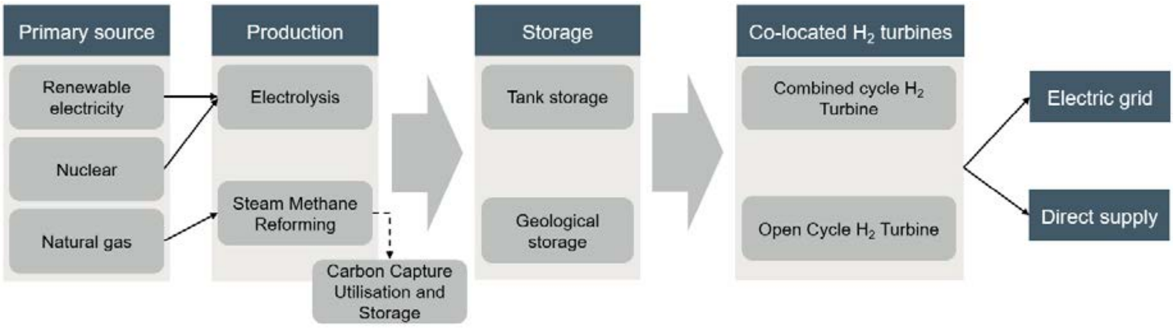
Furthermore, with higher shares of VRE, power systems become increasingly vulnerable to prolonged periods of low renewable output that often coincide with winter high pressures giving low wind, cold and dark conditions when demand is also high (aka "dunkelflaute" or "dark doldrum"). This will have an impact on the duration of output needed from peaking and mid-merit plant to compensate for the lack of supply. Full chronological load time-series and resource pattern computational models of power systems are necessary to assess the optimal

[66] IRENA, 2019, 'Hydrogen: A Renewable Energy Perspective'.

dispatch profile of each technology type. In absence of such modelling, here we compare how the cost competitiveness of hydrogen varies by capacity factor and then look at competitiveness by duration of discharge capability under a given capacity factor to draw general conclusions on hydrogen's potential role in a decarbonised power system in Energy Community CPs.

This section focuses on renewable hydrogen (i.e. generated through electrolysis from renewable electricity) for conversation back to electricity. This is illustrated in Figure 11 below.

Figure 11 Hydrogen supply chain for power storage



Source: ECA

4.1 Levelised cost of energy by capacity factor

4.1.1 Comparison technologies

Hydrogen would be in competition with other forms of storage and low or zero carbon flexible generation. For this analysis we are looking to compare the "mature" LCOE of low or zero carbon flexibility options. This represents the point year-to-year changes in costs become more marginal due to greater maturity following rapid cost reductions as the technologies commercialise (approximately by 2035). We compare hydrogen-powered combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT) plant with:

- **BESS of 1-hour and 4-hour discharge duration capability**. These durations have been chosen to reflect what is commonly deployed for ancillary service provision and intra-day arbitrage, respectively.
- **OCGT with CCUS:** Reflecting a typical peaking plant with a capacity factor of 10-15%.
- **CCGT with CCUS:** Reflecting a typical mid-merit plant with a capacity factor of 25-40%.
- **Pumped hydro:** A proven technology for peak period provision but highly constrained by available resources. Exact potential and costs are also dependent on local geological conditions, but we include the costs of pumped hydro with some baseline parameters for broad comparison.

In all cases it should be stressed that there is also substantial uncertainty over the future costs and capability of CCUS technology. Should these transpire to be higher, or more problematic, than envisaged then the relative attractiveness of renewable hydrogen storage and generation will improve.

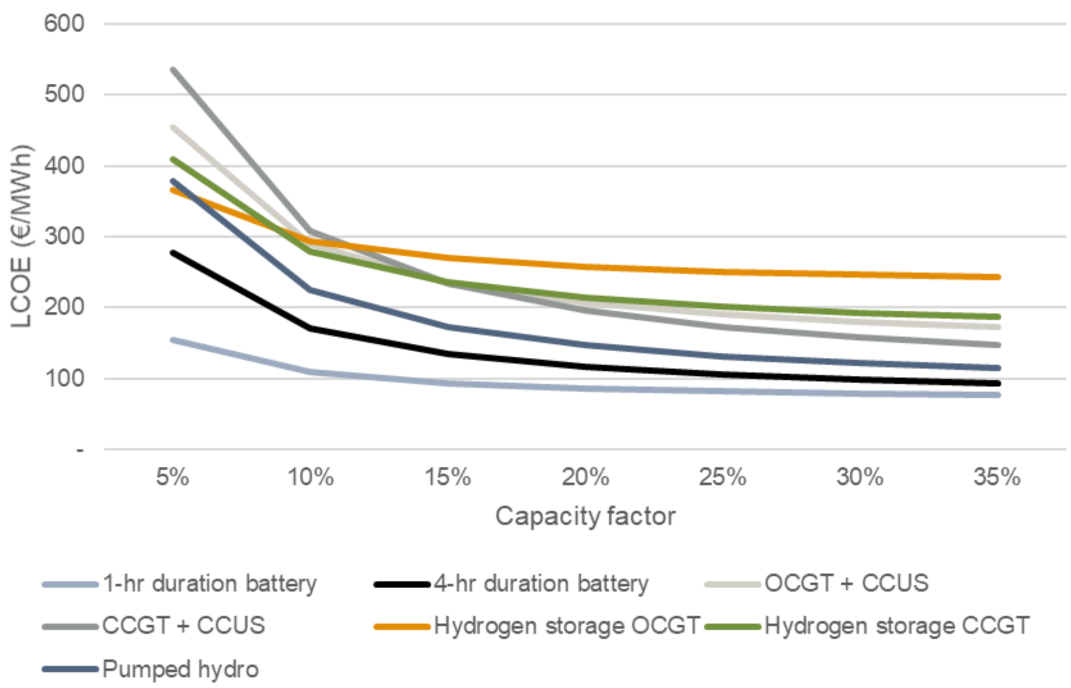
4.1.2 Results

Figure 12 to Figure 14 below compare the mature technology LCOE (given in 2020 Euros) by capacity factor, respectively at delivered hydrogen costs of:

- €1.7/MWh (base);
- €1.0/MWh (Low); and
- €2.4/MWh (High).

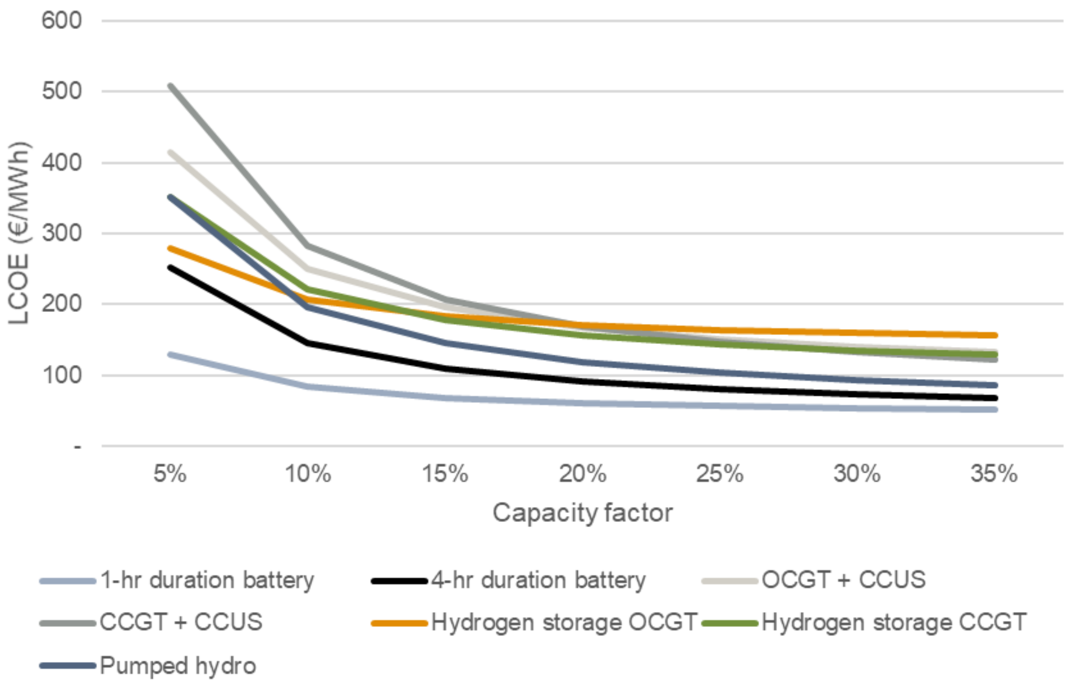
In each case, geological storage is assumed to be available for hydrogen. Costs for other technology costs remain unchanged through the three cases, with gas-fired units based on a delivered gas price of €23/MWh.

Figure 12 Competitiveness of mature renewable hydrogen power generation by capacity factor (Base-cost case)



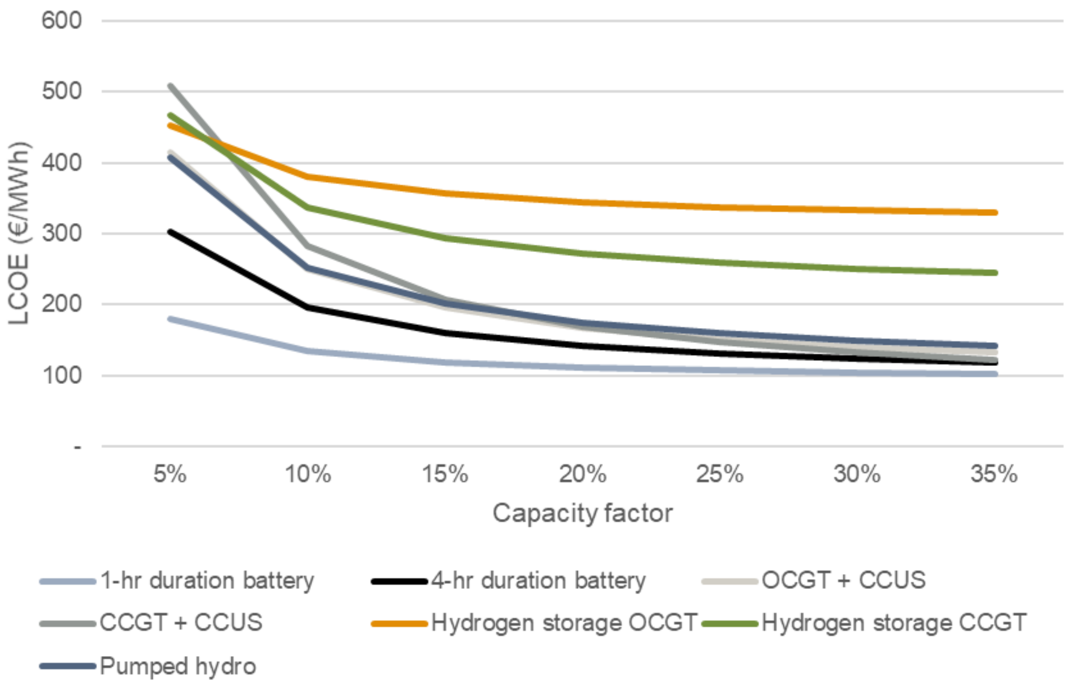
Source: Consultant calculations based on input data provided in Annex A5.

Figure 13 Competitiveness of mature renewable hydrogen power generation by capacity factor (Low-cost case)



Source: Consultant calculations based on input data provided in Annex A5.

Figure 14 Competitiveness of mature renewable hydrogen power generation by capacity factor (High-cost case)



Source: Consultant calculations based on input data provided in Annex A5.

In all cases, the cheapest generation option is a BESS. Nevertheless, availability of such units will frequently be constrained both by their limited discharge duration capability and their inability to recharge during intervals if output from VRE plant is low. The implications of discharge duration capability are evaluated further in the following sub-section.

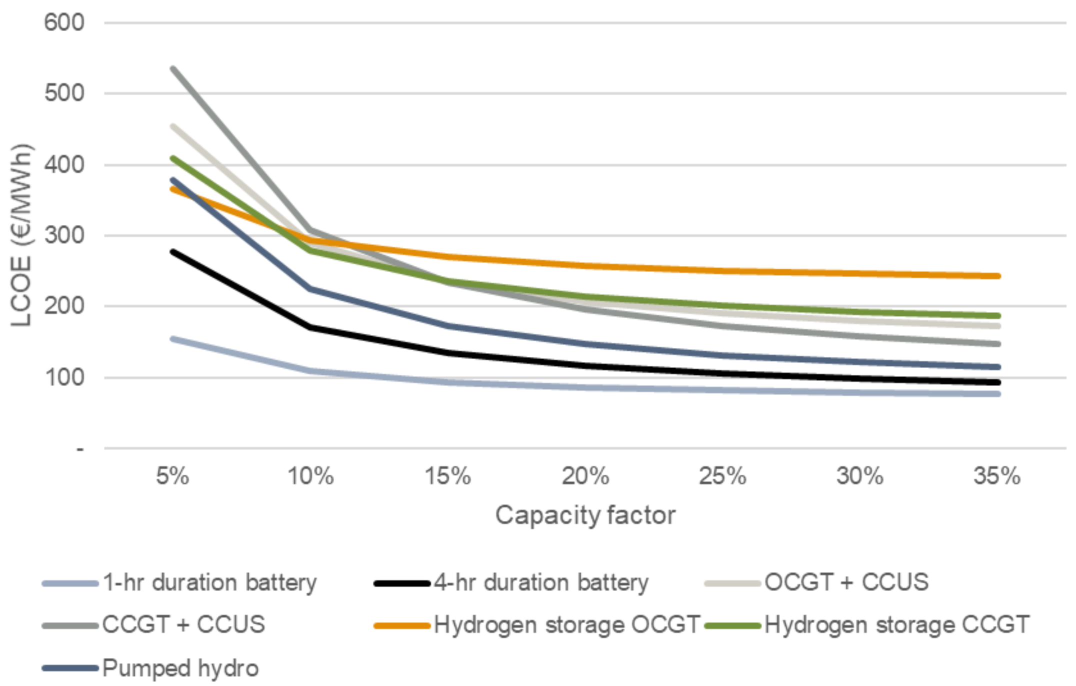
Similarly, pumped hydro is seen to be cheaper than renewable hydrogen options for all cases and capacity factors other than capacity factors under 10% in the Low-cost case where a renewable hydrogen-fired OCGT may prove more competitive. However, pumped hydro is highly constrained by suitable locations for development.

In the Low-cost case, a renewable hydrogen-fired OCGT is modelled to be cheaper than the equivalent OCGT plus CCUS up to a capacity factor of around 20% (at which point a CCGT would anyhow be preferred). However, under the Base-cost case a hydrogen-fired unit is only cheaper for the 5% capacity factor band, indicating a role reduced to that of a pure peaking plant. A hydrogen OCGT is not preferred under the High-cost case.

In the Low-cost case, a renewable hydrogen-fired CCGT is preferred to a gas plant with CCUS for capacity factors of around 15% up to 25%, with the CCGT plus CCUS being preferred for capacity factors of 30% and upwards. A hydrogen CCGT is not preferred for any capacity factor levels under the Base or High-cost cases.

Increasing the delivered cost of gas to €35/MWh and comparing to the Base-cost case for hydrogen production yields the results shown in Figure 15. Here the hydrogen OCGT is the preferred option (excluding BESS) at a capacity factor of 5%, and hydrogen CCGT the preferred option up to a capacity factor of around 15%.

Figure 15 Competitiveness of mature hydrogen storage by capacity factor (High delivered gas price)



Source: Consultant calculations based on input data provided in Annex A5.

The competitiveness of hydrogen in all the above cases is dependent on geological storage[67] with the use of pipes or tank storage limiting hydrogen's competitiveness to only OCGT peaking plant with a capacity factor of less than 10%.

Carbon price

As an alternative to assessing purely low carbon options, we have also estimated that a carbon price of around €190/tCO_2 would be necessary for renewable hydrogen storage to be competitive with an unabated OCGT or CCGT plant at capacity factors of 5% and 15% respectively.

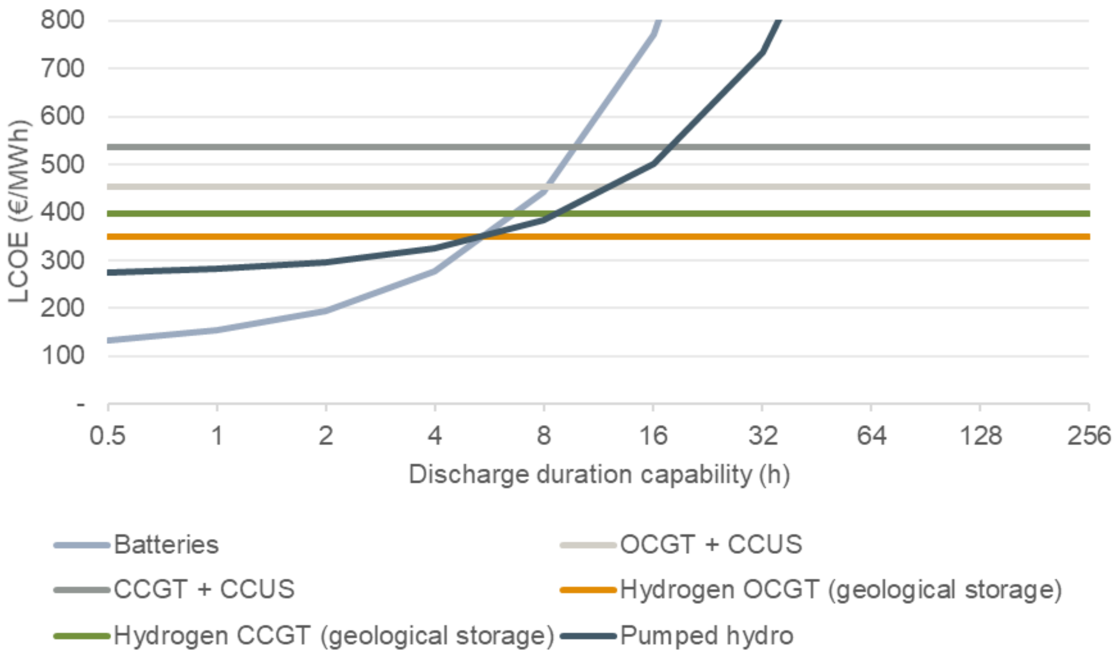
This contrasts with the IEA's 'Sustainable Development' carbon price projection of €106-119/tCO_2 by 2040 or the EU's 'Stated Policies' carbon price of €44/tCO_2 by 2040, or BP's 'Rapid' carbon price projection of €148-212/ tCO_2 or its 'business-as-usual' projection of €33-56/tCO_2 (see Annex A3).

4.2 Levelised cost of energy by dispatch duration

The cost of BESS is highly dependent on its discharge duration capability. We have therefore also modelled the relative competitiveness of hydrogen and CCUS units against BESS for different discharge duration capabilities under a given capacity factor. Figure 16 and Figure 17 provide the results using base case hydrogen production costs for capacity factors of 5% and 15% respectively.

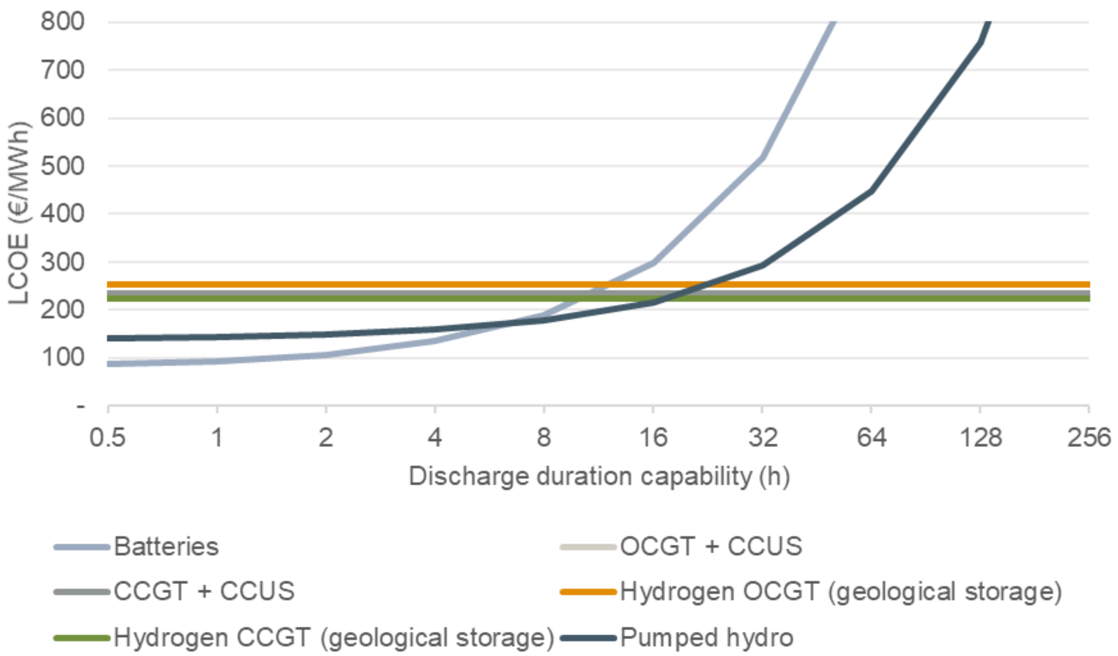
[67] Briefly reviewing the state of storage potential across the CPs (see the accompanying *CP assessment report* for more detail): Underground salt formations near Dumre are being considered for gas storage as part of Albania's gas masterplan, with potential relevance for Montenegro and Kosovo* too, subject to proposed gas pipelines. Old salt mines in the Tuzla region are a possibility for storage in Bosnia and Herzegovina, but this has not been explored in depth. In Georgia, feasibility studies have been completed for an underground gas storage facility in a depleted oil field, but its potential utilisation for hydrogen has not yet been assessed. The Moldovan government is considering two sites for underground gas storage, which could in principle be part of a strategic scheme for regional or national hydrogen development. There is no gas storage in North Macedonia but a prefeasibility study for a gas storage site is underway. Ukraine has some of the largest gas storage sites in Europe, including salt caverns. These storage sites could potentially be used for long term seasonal storage for Ukraine or serve as a transit hub for storage for European customers. The technical suitability and adaptability of these sites for storing hydrogen blends would need to be studied.

Figure 16 Competitiveness of mature technology costs for different dispatch duration capabilities with 5% capacity factor



Source: Consultant calculations based on input data provided in Annex A5.

Figure 17 Competitiveness of mature technology costs for different dispatch duration capabilities with 15% capacity factor



Source: Consultant calculations based on input data provided in Annex A5

For the 5% capacity factor case, hydrogen OCGT plant are estimated to be the cheapest form of supply at discharge durations of 8 hours or longer. For the 15% capacity factor case, BESS remain the lowest cost option up to and including durations of 8 hours. Both OCGT plus CCUS and hydrogen OCGT have lower costs than BESS for longer durations. However, hydrogen OCGT/CCGT plant are now higher cost than gas-fired plants with CCUS. Furthermore, these results assume low-cost geological storage is available for hydrogen OCGT/CCGT. If tank storage were the only option, it would increase hydrogen OCGT/CCGT costs by about €50/MWh, which would not change the result at a 5% capacity factor, but it would further push up hydrogen costs above OCGT/CCGT plus CCUS costs at a 15% capacity factor and increase the cross-over point for hydrogen and BESS to 16 hours duration and above.

4.3 Hydrogen as a "third way"?

In the context of the CPs, and the Western Balkans in particular, wider introduction of gas to the energy system has been a long-term policy goal that has struggled to be realised due to a variety of political, environmental, and economic reasons. This is now changing with gas finally to enter Albania with the newly operative Trans Adriatic Pipeline (TAP) as well as advanced developments to connect North Macedonia with Greece and Bosnia & Herzegovina with Croatia. These developments will bring the opportunity at least for gas-fired power station development and in some areas for distribution of gas for spatial heating. Nevertheless, significant population centres and some CPs will remain detached from the gas network for the foreseeable future.

Our analysis suggests that hydrogen will struggle to be economically competitive compared to batteries at short dispatch durations or gas with CCUS for longer dispatch durations and at higher capacity factors. However, if gas supply is not available to a CP (or parts of a CP), gas-to-power may not be an appropriate counterfactual. Furthermore, there are also significant uncertainties regarding the future cost trajectory and capability of CCUS to scale-up to the extent envisaged.

Where gas is not available or CCUS is deemed impractical, hydrogen could serve as a 'third way' to help achieve decarbonisation relative to building new coal plants (with effective, large-scale CCUS) or greenfield gas pipelines. Building nuclear plants could be another long-term decarbonisation option, but this may be an unrealistic prospect in the Western Balkans. Hydrogen power may offer the only practical low carbon option for enabling very high levels of RES penetration onto electricity grids, particularly in CPs without access to natural gas, such as Kosovo* and Montenegro. This is because having the electrolyser, storage and hydrogen turbine co-located there is no requirement for an extensive transmission network for the hydrogen. Furthermore, there is potential to leverage hydrogen storage to serve other applications such as transport or industry in addition to power storage.

4.4 Conclusions

For short-duration discharge requirements, BESS are considered highly likely to remain the most cost-efficient option. Even under the most optimistic cost case for hydrogen production (illustrated by the low-cost case with geological storage in the above discussion), hydrogen only offers a lower LCOE than BESS at discharge durations above eight hours.

Nevertheless, such requirements may be more frequent than initially assumed. This is because the discharge duration relates to any cumulative period of discharge without a possibility for recharge in the interim. In an electricity system with a high share of VRE there may be prolonged periods of scarce supply (high-pressure driven cold, stable winter conditions often coincide with periods of elevated demand). This could limit recharge opportunities and therefore require units with effective dispatch duration capabilities substantially beyond each individual period of dispatch. To ascertain the overall usage profile of such units requires full power system dispatch modelling. Our analysis suggests that for lower capacity factors (under 15%), hydrogen storage is expected to be cost competitive with CCUS-fitted units following full commercialisation. More favourable conditions (higher natural gas prices and lower hydrogen production costs) could see hydrogen competitive for capacity factors up to around 30%.

Natural gas is not a readily available option for some Energy Community CPs. Where hydro power is abundant this will anyhow likely prove favourable. Where it is not, and the alternatives are running CCUS-fitted lignite or coal at low load factors, or building new natural gas networks, the competitiveness of hydrogen will be significantly enhanced. A co-located hydrogen electrolyser with storage and turbine presents the potential for a self-contained project detached from a wider hydrogen or gas network.

5 Domestic heating

We consider the case of using hydrogen for domestic heating purposes. Particularly in countries with existing natural gas networks, hydrogen has been considered a decarbonisation option for heating.[68, 69] The cost implications go beyond boiler installation and network infrastructure costs as home appliances would also need to be converted and retrofitted to run on hydrogen.[70] This would require buy-in from households who would need to be assured of hydrogen's safety and that it is of equivalent utility.

5.1 Variable cost analysis

We concentrate on a variable cost calculation - if hydrogen cannot compete on a variable cost basis, it is particularly unlikely that it will be competitive once all investment costs are considered, except perhaps in cases where hydrogen heating is available on the back of hydrogen produced at nearby industrial sites (see the illustration of a local heating network developing around an established industrial hydrogen cluster in Figure 4 on p. 18). We also add on installation costs for reference, but these do not account for wider network costs, and may be highly variable by property (heat pump installation costs are particularly high for older, poorly insulated housing stock).

We calculate the implied variable costs of hydrogen heating relative to other heating options (gas boilers, electric heating, heat pumps, hybrid heat pumps, and biomass boilers) in Figure 18 using the assumptions in Table 14 of Annex A6.

Despite our assumption of a relatively low electricity input price of €0.05/kWh and long-run electrolyser efficiency improving to 74%, translating to a delivered hydrogen variable input cost of €1.7/kg, and assuming that the hydrogen is produced from carbon-free electricity, it is apparent that hydrogen has significantly higher variable costs compared to other heating options. This is largely due to the combined efficiency losses incurred by the electrolyser, through transmission and distribution, and the boiler itself, which give hydrogen heating an overall energy efficiency of only 62%. This compares to final assumed efficiency rates of 84% for gas boilers, 92% for electric heating, 77% for biomass boilers, and 322% for heat pumps.

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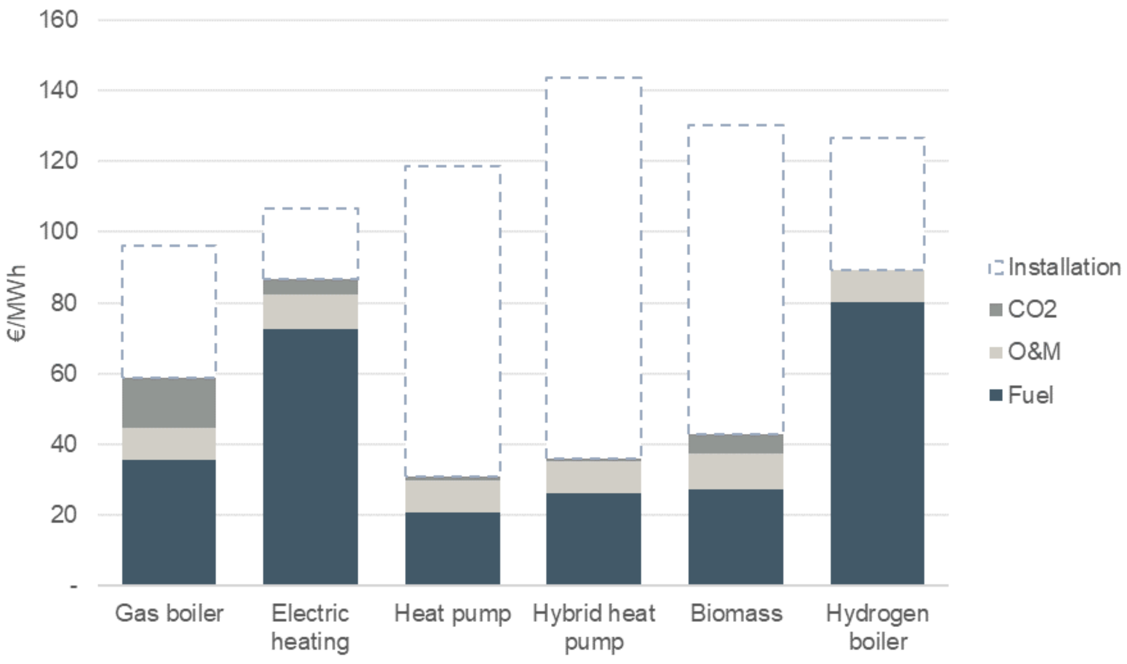
68 Perhaps the most advanced pilot project being the H21 Leeds City Gate project in the United Kingdom, a suite of gas projects led by Northern Gas Networks focused on demonstrating how the UK's existing gas grid can be repurposed to carry 100% hydrogen.
69 Hydrogen for off-grid heating, similar to LPG, could in principle be an option for CPs without gas networks, but the cost of transporting and storing the hydrogen likely make this uneconomic. Hence, it is generally only considered as a feasible option if a gas network is already present.
70 Northern Gas Networks estimates for the H21 Leeds City Gate project a total per property conversion cost of £3,078 (€3,470), which is consistent with a £3,500 (€3,950) per property estimate for converting the Isle of Man from town gas to natural gas in 2010 (https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf Table 5.6).

Figure 18 Variable and installation cost comparison of domestic heating options



Source: Consultant analysis

Heat pumps have low running costs given their high thermal efficiency, but also have substantial installation costs, particularly for older buildings. For hybrid heat pumps, greater differences between baseload and peak-load electricity prices and lower cost hydrogen than assumed in Figure 18[71] are required for it to be economically preferable to standard heat pumps given even higher installation costs. Similarly, biomass boilers have low running costs, but installing new, modern biomass boilers is costly. Many households across the CPs currently rely on old biomass boilers for heating, which will have low running costs today. However, these boilers will need to be replaced in future and given the high installation costs for modern biomass boilers, other low carbon options at lower cost may need to be considered.

District heating is another competing heating option for some CPs. We report a selection of recent district heating tariff rates across the CPs in Table 5 and compare to our base case estimate of hydrogen heating's variable cost in Figure 18. Some of these tariffs likely treat capital costs as sunk, but they are still a useful point of comparison, highlighting that hydrogen boilers will also struggle to compete with existing district heating setups on a variable cost basis. Including the *total* capex costs of hydrogen, i.e., new/retrofitted pipelines and appliances, would render hydrogen even less competitive.

Table 5 Contracting Party district heating tariffs

Contracting Party	Unit	Tariff rate/cost (€/MWh)
Bosnia & Herzegovina	€/MWh	40
Kosovo*	€/MWh	59
Moldova	€/MWh	64

[71] Plus, the potential ancillary benefit of hybrid heat pumps reducing stress on electricity distribution grids during peak hours.

Contracting Party	Unit	Tariff rate/cost (€/MWh)
Serbia	€/MWh	59
Ukraine	€/MWh	57
Hydrogen heating variable cost	**€/MWh**	**89**

Sources: ANRE Activity Report; IFC, 2015, Unlocking the Potential for Private Sector Participation in District Heating; DH Thermokos JSC and DH Gjakova JSC tariff rates for 2016; NERC, 2018, Annual Report of the National Energy and Utilities Regulatory Commission.

The IEA estimates that the delivered cost of hydrogen for heating would likely need to be in the range of €1.3-2.5/kg to be competitive with gas or electric heating in buildings in Western Europe and Russia,[72] but that estimate does *not* include the capital costs of equipment, which may mean hydrogen is only competitive for large commercial buildings. Given the multitude of potential factors at play, hydrogen's exact suitability will ultimately vary on a case-by-case basis.

5.2 Sensitivities

Exact variable heating costs will vary across the CPs. To cross-check our analysis, we consider sensitivities to the price of gas and electricity (Table 6).

Table 6 Domestic heating option sensitivities

Input	Unit	Assumption
Low gas price	€/kWh	0.01
High gas price	€/kWh	0.05
Low baseload electricity price	€/kWh	0.03
Low peak-load electricity price	€/kWh	0.10
High baseload electricity price	€/kWh	0.07
High peak-load electricity price	€/kWh	0.20

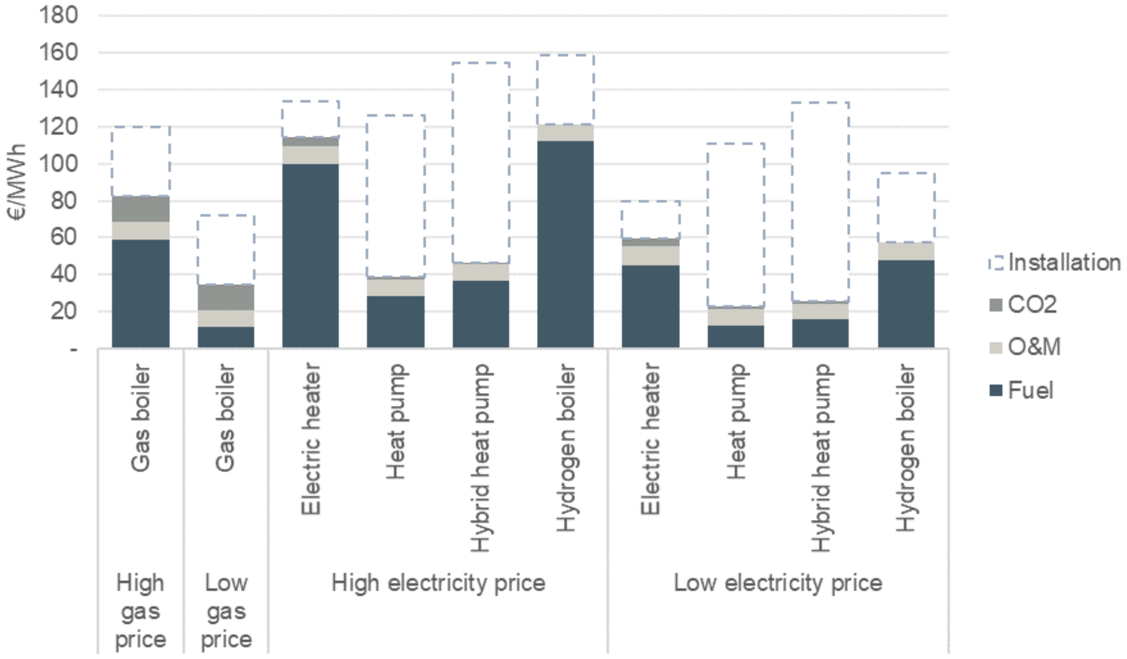
Source: Consultant assumptions.

Figure 19 shows that hydrogen boilers are only competitive with gas boilers under a combination of high gas prices and low electricity prices allowing for a hydrogen production cost of only €1/kg. However, factors that would make hydrogen heating cheaper, such as an existing gas grid that can be converted to hydrogen, would also imply that gas prices would be cheaper in a respective CP. Low electricity prices may also imply low gas prices.

If the electricity input cost for hydrogen production rises to €0.07/kWh, it is clearly less competitive than the other heating options. Hydrogen boilers may be competitive with electric heaters on a variable cost basis, but not after including boiler installation costs (and setting aside the costs of converting gas grids to hydrogen and appliance conversions).

[72] IEA, 2019, The Future of Hydrogen, Table 8.

Figure 19 Domestic heating option cost sensitivities



Source: Consultant analysis.

5.2.1 Carbon price

If a policymaker was looking to make hydrogen economically competitive solely through a carbon price, in our base case analysis (and assuming that the hydrogen itself is produced carbon-free):

- A carbon price of €130/tCO_2 would be required for hydrogen to be competitive with gas boilers on a variable cost basis:
  - For CPs that currently have gas heating, this illustrates that significant carbon prices would be needed to make zero carbon hydrogen heating economically competitive with gas boilers, outside of enforcing a zero carbon heating mandate.
- Assuming an average electricity grid emissions intensity of 100 kgCO_2/MWh, which, as an example, is the current nominal target for the UK electricity grid by 2030:
  - A carbon price of €225/tCO_2 would be required for hydrogen to be competitive with electric heating on a variable cost basis;
  - A carbon price of €300/tCO_2 would be required for hydrogen to be competitive with heat pumps on a variable cost basis.
- Assuming an average electricity grid emissions intensity of 350 tCO_2/MWh, i.e., roughly equivalent to that of a high-efficiency CCGT:

- A carbon price of €65/tCO_2 would be required for hydrogen to be competitive with electric heating on a variable cost basis;

- A carbon price of €85/tCO_2 would be required for hydrogen to be competitive with heat pumps on a variable cost basis.

These estimates contrast with the IEA's 'Sustainable Development' carbon price projection of €106-119/tCO_2 by 2040 or the EU's 'Stated Policies' carbon price of €44/tCO_2 by 2040, or BP's 'Rapid' carbon price projection of €148-212/ tCO_2 or its 'business-as-usual' projection of €33-56/tCO_2 (see Annex A3).

At low electricity grid emission levels, unrealistically high carbon prices are required given electrifying heat becomes inherently low carbon and the added inefficiency of using electrolysers. For CPs like Albania, with nearly 100% hydro-based electricity grids, the applicable carbon price practically becomes irrelevant.

For CPs that still expect to have relatively high-carbon electricity grids in the future, this may imply that hydrogen could be competitive on a variable cost basis with electric heating and heat pumps at carbon prices less than €100 tCO_2/MWh. However, it must then be assumed that the hydrogen is purely produced by electrolysers supplied by zero carbon electricity (dedicated RES facilities or nuclear power), which may have implications for electrolyser capital costs due to reduced utilisation rates.

5.3 Key inferences

The analysis in Section 5.1 demonstrates that hydrogen will struggle to compete on a *variable cost basis* with other heating options. Given that hydrogen heating will also require other significant investment costs, whether through building/retrofitting pipelines and converting appliances, it is unlikely that hydrogen can be an economically competitive heating option unless a few conditions play out:

- An existing gas grid can be cost effectively retrofitted;

- A carbon price of over €100/tCO_2 is applied;

- Electricity distribution grid limitations prevent the installation of heat pumps (which also face significant installation costs, particularly in older buildings); and

- Accelerated and aggressive decarbonisation policies include requirements for zero carbon heating, i.e., gas heating only incurring a carbon price is not considered sufficient.

Hydrogen heating may also have wider system benefits if sufficient geological storage is available to respond to seasonality, which will depend on CPs' geologies and perhaps in the long-term the potential for cross-border hydrogen trade from CPs or EU neighbours with storage potential, such as Ukraine, Serbia, Romania, Hungary, or Austria, to those without sufficient storage.

While a 100% switch to hydrogen heating may not be feasible in the near term, blending hydrogen in existing natural gas networks could be a transitional option. Such a strategy is currently under consideration in Ukraine, but it is not explicitly mentioned in any CP's energy plans or strategies. It has been estimated that up to 20% hydrogen blending by volume could be feasible without significant infrastructure modifications, subject to location and current system usage.[73] The percentage could be even higher (30-50%) at the distribution level and for existing boilers and gas cookstoves.[74] The exact potential for blending across Europe is currently being studied from technological, safety, and market aspects by different stakeholders in the EU and the CPs. This could lower the carbon intensity of current natural gas grids[75] and provide an initial "anchor load" to support the scale up of hydrogen production.

[73] GRTgaz, 'Technical and economic conditions for injecting hydrogen into natural gas networks', Final report, June 2019.
[74] IEA, 2019, The Future of Hydrogen, Figure 25.
[75] Depending on the source of the hydrogen, and this benefit will also be limited by hydrogen's lower volumetric energy density relative to methane.

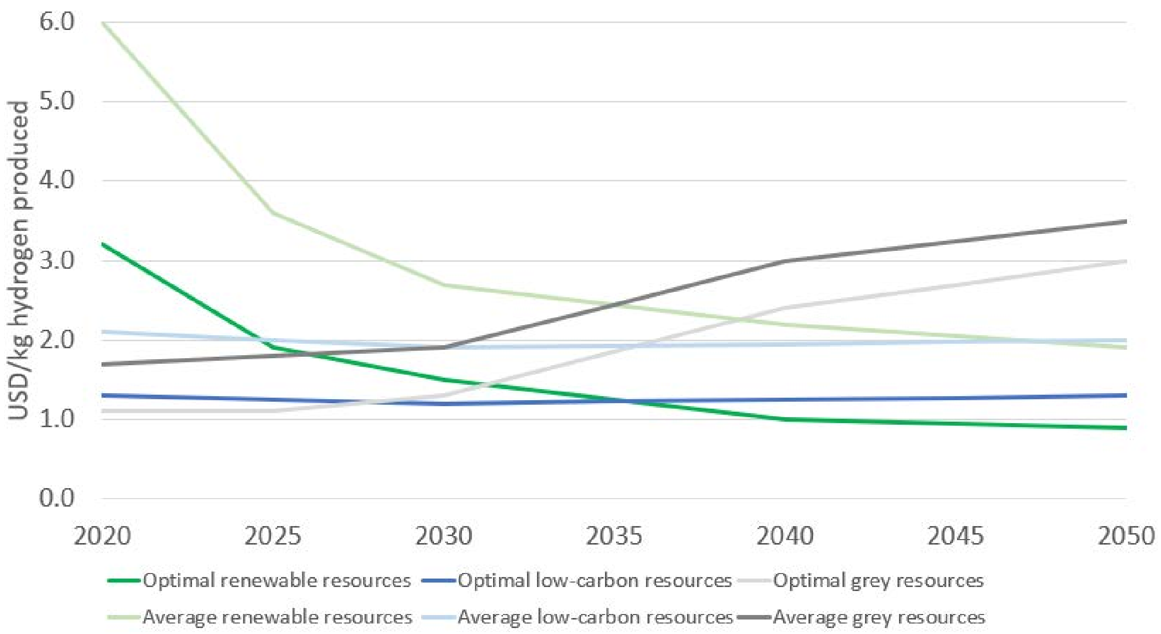
Annexes

A1 Hydrogen production costs and cost evolution

To provide context to the produced hydrogen netback results for transport in Section 2, we reproduce Section 3.2.4 from the *International review* report below.

Hydrogen production costs are critically dependent on the production method and production location, as estimates of future costs vary significantly. However, indicative production costs (reported in USD/kg by the Hydrogen Council[76]) are provided in Figure 20.

Figure 20 Indicative costs of hydrogen production across different types of location



Source: Hydrogen Council, Path to hydrogen competitiveness: A cost perspective, 20 January 2020.

The cost comparisons shown in Figure 20 across the different production methods and in varying locations are subject to high levels of uncertainty due to the immaturity of low carbon and renewable production routes, the lack of large-scale production examples and currently no developed hydrogen markets. It is also hard to speculate on regional differences and so these values should only be taken as estimates as in reality there will inevitably be a large range of production costs. Recognising this uncertainty, it is perhaps more instructive to focus on the factors driving the costs, qualitatively how the routes compare to each other and how they are likely to change in the future. The lowest hydrogen production cost will vary both by time and location, for example electrolysis costs will have a different trajectory depending on the use case and region and the cost of CCS depends on availability, distance, and scale.

'Optimal renewable' refers to places with good solar and wind resources such as the Middle East, Chile, or Australia. Leveraging this low production cost provides the incentive for global

[76] This report applies an assumed exchange rate of $/€: 1.18 throughout.

hydrogen trading to benefit geographies with lower renewable capacity such as the EU. ‘Optimal low carbon’ refers to areas with particularly low-cost natural gas and available CCS such as Russia and this will be one of the lowest cost options for hydrogen production, especially in the short term as renewable hydrogen production develops and scales up. ‘Grey resources’ refer to conventional fossil-based hydrogen production and becomes increasingly uncompetitive everywhere because of the rising cost of CO_2. A carbon price of USD50/tCO_2 in 2030 rising to USD300/tCO_2 in 2050 has been assumed.

The less mature technologies such as CCS and electrolysis in principle offer greater potential for cost reductions (compared to mature fossil-based routes such as SMR) as hydrogen systems are scaled up. Costs will inevitably fall in time as technologies, manufacturing, and operations mature.

A2 Transport

A2.1 Netback calculation description

Netback pricing can be used to determine the maximum feasible price of a fuel, in this case hydrogen, on a per-unit basis. It is used to ensure a new fuel on the market can compete with existing options in a particular sector, such as the fuelling of trucks and trains in the transport sector.

For a given sector, hydrogen can only compete with an incumbent fuel if the annualised costs following a switch to hydrogen are lower than current annualised costs. Equivalently, the following condition must hold:

$$TC_H \leq TC_I$$

$$TC_H = F_H + O_H + C_H$$

$$TC_I = F_I + O_I + C_I$$

Where:

- TC_H is the total annualised sectoral unit cost (EUR/MWh) under the hypothetical scenario of hydrogen adoption, which is equal to the sum of:
  - the unit fuel cost of hydrogen, F_H (€/MWh-equivalent[77]);
  - the annual operating and maintenance (O&M) unit cost in the sector, O_H (€/MWh);
  - the annualised capital unit cost in the sector, C_H (€/MWh);
- TC_I is the present total annualised sectoral unit cost with the incumbent fuel and is the equivalent summation of fuel unit costs (F_I)[78], current annualised O&M (O_I), and annualised capital costs (C_I) in the sector.

The above condition can equivalently be expressed as follows:

$$F_H + O_H + C_H \leq F_I + O_I + C_I$$

$$F_H \leq F_I + (O_I - O_H) + (C_I - C_H)$$

$$= F_I + \Delta O + \Delta C$$

That is, for a given sector, the hydrogen unit fuel cost must be no greater than the sum of the incumbent unit fuel cost, the change in annual O&M unit costs and the change in annualised

[77] Hydrogen production cost is typically expressed per kilogram, so we convert all energy-related calculations to a per kg of hydrogen basis for the final netback number.
[78] Fossil-fuel costs would be inclusive of carbon or emissions costs. For hydrogen, zero carbon hydrogen is generally assumed, but this will depend on other lifecycle costs and the carbon intensity of the actual electricity supplied to the electrolyser.

capital unit costs. Due to uncertainties in estimating the above costs, it is standard practice to conduct netback pricing under different scenarios representing a low-cost, high-cost and intermediate case.

In Box 1, we provide an example calculation of netback pricing for a switch from an incumbent diesel fuel to liquified natural gas (LNG) in the trucking sector of a country.

Box 1 Netback pricing in the trucking sector

Suppose that a country is considering switching from diesel to LNG in its trucking sector, due to reported low costs and environmental benefits. The country conducts a netback pricing analysis to see if the new fuel can compete with diesel. For this to occur, the following condition must hold:

$$F_L \leq F_D + (C_D - C_L) + (O_D - O_L)$$

where subscript D represents diesel and L represents LNG.

First, the diesel fuel unit cost (€/km) is calculated as the diesel cost per litre (€/l) divided by the litre consumption of diesel per km travelled (l/km).

Second, the increase in capital costs is calculated. The diesel capital unit cost (€/km) is calculated as the cost of each diesel truck (€) divided by the product of the annual distance driven by each truck (km) and the truck's expected life (years). The LNG capital unit cost (€/km) is calculated through an equivalent calculation.

Third, the O&M increase of a switch to LNG is calculated. For the purposes of this example, it is assumed that there would be a 20% increase in costs relative to the status quo.

Finally, the maximum LNG fuel cost per km is calculated based on the above cost. This is then converted into a unit cost of euros per MWh, which is more comparable across sectors.

	Diesel fuel cost per km (F_D)		
(1)	Diesel fuel consumption	*l / km*	0.35
(2)	Diesel cost	*€ / l*	0.84
(3) = (2) / (1)	Diesel cost per km	*€ / km*	**0.29**
	Capital cost diesel truck per km (C_D)		
(4)	Cost of diesel truck vehicle	*€*	145,000
(5)	Annual distance driven by truck	*km*	200,000
(6)	Truck life	*years*	4
(7) = (4) / [(5) * (6)]	Cost of diesel truck per km	*€ / km*	**0.18**
	Capital cost LNG truck per km (C_L)		
(8)	Cost of LNG truck vehicle	*€*	210,000
(9)	Annual distance driven by truck	*km*	200,000
(10)	Truck life	*years*	4
(11) = (8) / [(9) * (10)]	Cost of LNG truck per km	*€/ km*	**0.26**
	O&M cost diesel truck per km (O_D)		
(12)	O&M cost per km	*€ / km*	**0.11**
	O&M cost LNG truck per km (O_L)		
(13)	O&M increase percentage	*%*	20%
(14) = (12) * [1 + (13)]	O&M cost per km	*€ / km*	**0.13**

	Max LNG fuel cost (F_L)		
(15) = (3) + [(12) - (14)] + [(7) - (11)]	Max LNG fuel cost per km	*€ / km*	0.19
(16)	LNG to drive 1 km	*kg*	0.25
(17) = (15) / (16)	Max LNG fuel cost per kg LNG	*€ / kg*	0.76
(18)	MWh per kg of LNG	*MWh / kg*	0.015
(19) = (17) / (18)	Max LNG fuel cost	*€ / MWh*	**50.3**

Source: ECA

A2.2 Assumptions

Table 7 contains the latest reported diesel prices across the CPs used in the transport netback analysis.

Table 7 Current reported diesel prices across the CPs

Contracting Party	Reported diesel price (€/litre)
Albania	1.134
Bosnia & Herzegovina	0.938
Georgia	0.589
Kosovo*	1.000
Moldova	0.697
Montenegro	1.020
North Macedonia	0.884
Serbia	1.237
Ukraine	0.726

Source: 26 Jan 2021 data from https://www.globalpetrolprices.com/. The diesel price for Kosovo* was collected from https://www.mylpg.eu/stations/kosovo/prices/, which only reports a price from 2015.

Technical parameters for FCEVs, BEVs, and diesel vehicles are presented in Table 8.

Table 8 Transport netback assumptions

Trucking assumptions				
	Unit	**Hydrogen**	**Battery**	**Diesel**
Vehicle cost, 2020	€	238,000	223,000	173,000
Vehicle cost, 2030		200,000	185,000	185,000
O&M cost	€/km	0.09	0.09	0.13
CO_2 emissions, 2020	gCO_2/km	750	450	1,250
CO_2 emissions, 2030		400	200	900

	Trucking assumptions			
Fuel consumption, 2020	Hydrogen/Battery: kWh/km Diesel: l/km	2.44	1.47	0.34
Fuel consumption, 2030		2.11	1.25	0.24
	Buses assumptions			
	Unit	**Hydrogen**	**Battery**	**Diesel**
Vehicle cost, 2020	€	450,000	343,000	218,000
Vehicle cost, 2030		350,000	263,000	
O&M cost, 2020	€/km	0.34	0.21	0.34
O&M cost, 2030	€/km	0.28	0.21	0.34
CO_2 emissions, 2020	gCO_2/km	225	525	1,500
CO_2 emissions, 2030		165	138	1,100
Air pollution cost	€/km	-	-	0.018
Excess noise cost	€/km	-	-	0.087
Fuel consumption, 2020	Hydrogen: kg/km Battery: kWh/km Diesel: l/km	0.09	1.75	0.409
Fuel consumption, 2030		0.08	1.38	0.389

Sources: Diesel/FCEV/BEV truck parameters: Moultak, et al., 2017, 'Transitioning to Zero-Emission Heavy-Duty Freight Vehicles', ICCT White Paper; Hall, D. and N. Lutsey, 2019, 'Estimating the Infrastructure Needs and Costs for the Launch of Zero-Emission Trucks', ICCT White Paper; and Transport & Environment, 2020, 'Comparison of hydrogen and battery electric trucks'. Overhead catenary infrastructure: Mareev, I. and D. Uwe Sauer, 2018, 'Energy Consumption and Life Cycle Costs of Overhead Catenary Heavy-Duty Trucks for Long-Haul Transportation', Energies, 11, 3446 (adapted to a low-volume case). Diesel/FCEV/BEV urban bus parameters: Hydrogen Europe: Hydrogen Buses; Transport & Environment, 2018, 'Electric buses arrive on time'; Quarles, N. et al, 2020, 'Costs and Benefits of Electrifying and Automating Bus Transit Fleets', Sustainability, 12, 3977; FCHJU, 2016, 'Clean Hydrogen in European Cities'; and Aber, J., 2016, 'Electric Bus Analysis for New York City Transit'. EV charging cost: TNO, 2018, 'Assessments with respect to EU HDV CO_2 Legislation'. General parameters for CO_2 emissions associated with hydrogen/BEV vehicles, including lifecycle emissions (will depend on the emissions intensity of each CP's electrical grid in practice): ICCT Briefing, 2018, 'CO_2 emissions and fuel consumption standards for heavy-duty vehicles in the EU' and Embarq, 'Exhaust Emissions of Transit Buses'. Air pollution and excess noise costs: Transport & Environment, 2018, 'Electric buses arrive on time'. A CO_2 price of €40/tCO_2 is assumed.

A3 Carbon pricing

As a benchmark reference for the carbon prices required for hydrogen to "breakeven" calculated throughout this report, Table 9 below reports the carbon price projections contained within the latest energy outlooks from BP[79] and the IEA[80].

Table 9 Projected carbon prices (€/tCO_2)

BP Energy Outlook 2020 edition				
Scenario	**Country**	**2025**	**2040**	**2050**
Rapid	Developed	32.6	169.5	211.9
	Emerging	2.6	84.7	148.3
Business-as-usual	Developed	22.6	42.5	55.5
	Emerging	2.3	19.6	32.8
IEA World Energy Outlook 2020				
Scenario	**Country**	**2025**	**2040**	**2050**
Stated Policies	Canada	28.8	32.2	-
	Chile	6.8	16.9	-
	China	14.4	29.7	-
	EU	28.8	44.1	-
	South Africa	8.5	20.3	-
Sustainable Development	Advanced economies	53.4	118.6	-
	Developing economies	36.4	105.9	-

Source: BP, Energy Outlook 2020 edition, p 14. IEA, World Energy Outlook 2020, Table 2.3. All values converted to €/tCO_2 using an exchange rate of $/€: 1.18.

[79] BP, Energy Outlook 2020 edition.
[80] IEA, World Energy Outlook 2020.

A4 Industrial applications

A4.1 Ammonia

Table 10 Ammonia production cost assumptions

	Unit	2020	2030	2050
Electrolysis				
Capex	€/tNH_3	800	725	645
Opex	% of capex		1.5%	
Electricity consumption	kWh/tNH_3	10,500	9,800	9,200
Emissions factor	tCO_2/tNH_3		-	
Natural gas				
Capex	€/tNH_3		770	
Opex	% of capex		2.5%	
Gas consumption	kWh/tNH_3	11,700	10,650	8,950
Electricity consumption	kWh/tNH_3		85	
Emissions factor	tCO_2/tNH_3	2.35	2.14	1.80
Natural gas + CCUS				
Capex	€/tNH_3	1,110	1,070	990
Opex	% of capex		2.5%	
Gas consumption	kWh/tNH_3	11,700	10,650	8,950
Electricity consumption	kWh/tNH_3		360	
Emissions factor	tCO_2/tNH_3	0.12	0.11	0.09
Coal				
Capex	€/tNH_3		1,845	
Opex	% of capex		5.0%	
Coal consumption	t/tNH_3		1.5	
Electricity consumption	kWh/tNH_3		1,030	
Emissions factor	tCO_2/tNH_3		3.90	
Coal + CCUS				
Capex	€/tNH_3		2,385	
Opex	% of capex		5.0%	
Coal consumption	t/tNH_3		1.5	
Electricity consumption	kWh/tNH_3		1,470	
Emissions factor	tCO_2/tNH_3		0.20	

Source: IEA, 2019, The Future of Hydrogen, Assumptions Annex. USD values converted to € at a rate of 1.18. Electrolysis includes the cost of both the ammonia plant and an on-site electrolyser.

A4.2 Iron and steel

Table 11 Iron and steel production cost assumptions

		Electrolyser DRI-EAF			Natural gas DRI-EAF	Natural gas DRI-EAF + CCUS	BF-BOF
	Unit	2020	2030	2050			
Capex	€/t steel	800	725	640	500	545	510
Opex	% of capex	16%	18%	20%	25%	23%	23%
Biomass consumption	GJ/t steel		1.9		-	-	-
Gas consumption	kWh/t steel		-		2,810	2,810	-
Coal consumption	t/t steel		-		0.02	0.02	0.64
Electricity consumption	kWh/t steel	4,080	3,860	3,667	695	750	195
Iron ore consumption	t/t steel		0.586		0.586	0.586	1.370
Steel scrap consumption	t/t steel		0.710		0.710	0.710	0.125
Limestone consumption	t/t steel		0.088		0.088	0.088	0.270
Emissions factor	tCO_2/t steel	0.025	0.024	0.022	0.890	0.089	1.900

Sources: IEA, 2019, The Future of Hydrogen, Assumptions Annex; Raw materials: World Steel Association, Steel Facts 2018; Electrolyser DRI-EAF CO_2 emissions: Toktarova, et al., 2020, 'Pathways for Low Carbon Transition of the Steel Industry', Energies, 13 (15), 3840; USD values converted to € at a rate of 1.18. Electrolysis includes the cost of both the iron and steel plant and an on-site electrolyser.

A4.3 Methanol

Table 12 Methanol production cost assumptions

	Unit	2020	2030	2050
Electrolysis				
Capex	€/tMeOH	670	505	325
Opex	% of capex		1.5%	
Electricity consumption	kWh/tMeOH	7,055	6,585	6,167
CO_2 feedstock	tCO_2/tMeOH		1.41	
Emissions factor	tCO_2/tMeOH		-	
Natural gas				

	Unit	2020	2030	2050
Capex	€/tMeOH		310	
Opex	% of capex		2.5%	
Gas consumption	kWh/tMeOH	9,420	9,167	8,750
Electricity consumption	kWh/tMeOH		85	
Emissions factor	tCO_2/tMeOH	0.80	0.70	0.60
Natural gas + CCUS				
Capex	€/tMeOH	445	430	415
Opex	% of capex		2.5%	
Gas consumption	kWh/tMeOH	9,420	9,167	8,750
Electricity consumption	kWh/tMeOH	195	195	167
Emissions factor	tCO_2/tMeOH	0.04	0.04	0.03
Coal				
Capex	€/tMeOH		635	
Opex	% of capex		5.0%	
Coal consumption	t/tMeOH	1.8	1.7	1.6
Electricity consumption	kWh/tMeOH		1,030	
Emissions factor	tCO_2/tMeOH	3.30	3.10	2.70
Coal + CCUS				
Capex	€/tMeOH	1,275	1,230	1,145
Opex	% of capex		5.0%	
Coal consumption	t/tMeOH	2.1	2.0	1.9
Electricity consumption	kWh/tMeOH		1,080	
Emissions factor	tCO_2/tMeOH	0.17	0.15	0.14

Source: IEA, 2019, The Future of Hydrogen, Assumptions Annex; CO_2 feedstock: Szima, S. and C-C Cormos, 2018, ‘Improving methanol synthesis from carbon-free H_2 and captured CO_2: A techno-economic and environmental evaluation’, Journal of CO_2 Utilization, 24, 555-563. USD values converted to € at a rate of 1.18. Electrolysis includes the cost of both the methanol plant and an on-site electrolyser.

A5 Power storage

Table 13 Power storage input assumptions

Input	Unit	Assumption
Rate of return	%	8%
OCGT efficiency (LHV[81])	%	40%
CCGT efficiency (LHV)	%	60%
Hydrogen storage life	Years	25
OCGT/CCGT project life	Years	25
BESS life	Years	10
CO_2 cost	€/tCO_2	40
CO_2 transport and storage cost	€/tCO_2	17
Depth of BESS discharge	%	90%
BESS roundtrip efficiency	%	86%
Electrolyser carbon emissions (RES)	tCO_2/MWh	0.008
Electrolyser efficiency	%	74%
Hydrogen OCGT costs		
Capex	€/kW	455
Opex	€/kW/year	20.3
OCGT efficiency (HHV[82])	%	33.8%
Hydrogen CCGT costs		
Capex	€/kW	909
Opex	€/kWh	28.2
CCGT efficiency (HHV)	%	50.7%
Hydrogen storage		
Tank storage	€/kg	2.2
Geological storage	€/kg	0.2
Gas-fired OCGT with CCUS		
Capex	€/kW	1,245
Opex	€/kW/year	27.8
OCGT efficiency (HHV)	%	31%
Unabated CO_2 emissions	tCO_2/MWh	0.536
CCUS effectiveness	%	90%
Abated CO_2 emissions	tCO_2/MWh	0.054
Gas-fired CCGT with CCUS		
Capex	€/kW	1,700
Opex	€/kW/year	38.6
CCGT efficiency (HHV)	%	46%

[81] Lower heating value.
[82] Higher heating value.

Input	Unit	Assumption
Unabated CO_2 emissions	tCO_2/MWh	0.354
CCUS effectiveness	%	90%
Abated CO_2	tCO_2/MWh	0.035
BESS		
Capex (power-related)	€/kW	81
Capex (energy-related)	€/kWh	93
Opex (power-related)	€/kW	8.5
Opex (energy-related)	€/kWh	2.5

Sources: Battery costs: IEA, 2019, The Future of Hydrogen; CCGT/OCGT CO_2 emissions: Committee on Climate Change, 2019, 'Net Zero: The UK's contribution to stopping global warming'; CCGT/OCGT CCUS efficiency: Energy Technologies Institute, 2017, 'Potential Role of Combined Cycle Gas Turbines with Carbon Capture Storage', Low Carbon Technologies for the UK Energy System; CCGT/OCGT CCUS opex: Aurora Energy Research, 2020, 'Hydrogen for a Net Zero GB: An integrated energy market perspective'; Hydrogen storage costs: Ahluwalia, R.K., et al., 'System Level Analysis of Hydrogen Storage Options', U.S. DOE Hydrogen and Fuel Cells Program, 2019 Annual Merit Review and Peer Evaluation Meeting.

A6 Domestic heating

Table 14 Heating costs base case input assumptions

Input	Unit	Assumption
Rate of return	%	8%
Heating option lifetime	Years	15
Annual heating energy requirement	MWh	10
Installation cost		
Gas or hydrogen boiler	€	3,200
Electric resistive heater	€	1,695
Heat pump	€	7,500
Hybrid heat pump	€	9,200
Biomass boiler	€	7,500
Fuel cost assumptions		
Gas price	€/kWh	0.03
Baseload electricity price	€/kWh	0.05
Peak-load electricity price	€/kWh	0.15
Biomass cost	€/kWh	0.02
O&M costs		
Gas or hydrogen boiler	€/year	92
Electric resistive heater	€/year	100
Heat pump	€/year	90
Hybrid heat pump	€/year	88
Biomass	€/year	100
Boiler efficiency		
Electrolyser	%	74%
Gas / hydrogen boiler	%	87%
Heat pump	%	350%
Biomass	%	77%
Transmission and Distribution losses		
Gas / hydrogen grid	%	3%
Electric grid	%	8%
CO_2 emissions		
Gas	tCO_2/MWh	0.295
Electricity	tCO_2/MWh	0.100
Biomass	tCO_2/MWh	0.103
Applied carbon price	€/tCO_2	40

Sources: Costs and efficiencies: Imperial College London, 2018, Analysis of Alternative UK Heat Decarbonisation Pathways, For the Committee on Climate Change and Committee on Climate Change, 2018, 'Hydrogen in a low carbon economy'; Cost of biomass: Mandova, H. et al, 2018, 'Achieving carbon-neutral iron and steelmaking in Europe through the deployment of bioenergy with carbon capture and storage', Journal of Cleaner Production, 218 (1), 118-129; O&M costs: Popovski, E. et al, 2018, 'Technical and economic feasibility of sustainable heating and cooling supply options in southern European municipalities - A case study for Matosinhos, Portugal', Energy, 153 (C), 311-323; CO_2 emissions: Houses of Parliament: Parliamentary Office of Science & Technology, 2016, 'Carbon Footprint of Heat Generation', POSTnote 523.