

# IEA G20 Hydrogen report: Assumptions

This annex collects the various assumptions that underpin the analyses throughout *The Future of Hydrogen*. For technologies, global averages are presented. However, several analyses in the report present regional examples, for which costs will vary with material and labour inputs and differ from the global average.

These input parameters reflect choices made by the IEA in light of the limited space to present multiple sensitivity analyses. However, there is no doubt that many of the quantitative aspects of hydrogen-related technologies face uncertainties that are compounded when only one case is shown per chart or one illustrative example described. For that reason, the IEA website is home to a growing number of interactive graphics that allow the user to explore variations on the assumptions listed below.

## General inputs

### General

- All costs in USD (2017)
- Discount rate: 8%.
- CO<sub>2</sub> transport and storage cost for CCUS: USD 20/tCO<sub>2</sub> (all regions)
- Water costs are not considered.

### Commodity prices

Region	Gas price (USD/MBtu)			Lignite price (USD/tonne)		
	Today	2030	Long term	Today	2030	Long term
China	8.5	9.3	9.2	30.1	20.6	20.3
European Union	7.3	8.0	7.9	30.1	20.6	20.3
Japan	10.9	10.6	10.2	-	-	-
Australia	5.4	6.1	6.0			
United States	3.3	3.8	4.0	36.6	24.7	24.3
Minimum	2.9	3.5	3.4	30.1	10.6	10.4
Maximum	11	10.7	10.3	40.1	30.6	20.3

Notes: Notes: MBtu = million British thermal units. Natural gas prices are weighted averages expressed on a gross calorific-value basis. The US natural gas price reflects the wholesale price prevailing on the domestic market. The European Union and China gas prices reflect a balance of pipeline and liquefied natural gas (LNG) imports, while the Japan gas price is solely LNG imports; the LNG prices used are those at the customs border, prior to regasification. Lignite prices are weighted averages adjusted to 6 000 kilocalories per kilogramme.

### CO<sub>2</sub> prices

Region	CO <sub>2</sub> price (USD/tCO <sub>2</sub> )		
	Today	2030	Long term
Advanced economies	5-16	100	160
Emerging economies	0-5	75	145

# Production pathways

## Hydrogen

Technology	Parameter	Units	Today	2030	Long term
Water electrolysis	CAPEX	USD/kW <sub>e</sub>	900	700	450
	Efficiency (LHV)	%	64	69	74
	Annual OPEX	% of CAPEX	1.5	1.5	1.5
	Stack lifetime (operating hours)	hours	95 000	95 000	100 000
Natural gas reforming	CAPEX	USD/kW <sub>H<sub>2</sub></sub>	910	910	910
	Efficiency (LHV)	%	76	76	76
	Annual OPEX	% of CAPEX	4.7	4.7	4.7
	Emission factor	kgCO <sub>2</sub> /kgH <sub>2</sub>	8.9	8.9	8.9
Natural gas reforming with carbon capture	CAPEX	USD/kW <sub>H<sub>2</sub></sub>	1 680	1 360	1 280
	Efficiency (LHV)	%	69	69	69
	Annual OPEX	% of CAPEX	3	3	3
	CO <sub>2</sub> capture rate	%	90	90	90
	Emission factor	kgCO <sub>2</sub> /kgH <sub>2</sub>	1.0	1.0	1.0
Coal gasification	CAPEX	USD/kW <sub>H<sub>2</sub></sub>	2 670	2 670	2 670
	Efficiency (LHV)	%	60	60	60
	Annual OPEX	% of CAPEX	5	5	5
	Emission factor	kgCO <sub>2</sub> /kgH <sub>2</sub>	20.2	20.2	20.2
Coal gasification with carbon capture	CAPEX	USD/kW <sub>H<sub>2</sub></sub>	2 780	2 780	2 780
	Efficiency (LHV)	%	58	58	58
	Annual OPEX	% of CAPEX	5	5	5
	CO <sub>2</sub> capture rate	%	90	90	90
	Emission factor	kgCO <sub>2</sub> /kgH <sub>2</sub>	2.1	2.1	2.1

Notes: 25-year lifetime and a 95% availability factor assumed for hydrogen production from natural gas and coal. Availability factors for electrolysis are based on the full load hours of electricity shown in following table. For water electrolysis, possible revenues from oxygen sales have not been considered in the cost analysis.

Sources: References in Table 1 of Chapter 2 for electrolysis IEAGHG (2014), "CO<sub>2</sub> capture at coal based power and hydrogen plants", IEAGHG (2017), "Techno-economic evaluation of SMR based standalone (merchant) hydrogen plant with CCS".

## Electricity prices and full load hours

Region	Grid			Full load hours	Variable renewable electricity	
	Electricity price (USD/MWh)		Long term		Electricity price (USD <sub>2017</sub> /MWh)	Optimised full load hours
	Today	2030			Long term	Long term
Australia	86	156	163	5 000	31	2 321
Chile	-	-	-	5 000	23	2 758
China	113	140	137	5 000	18	2 822
European Union	98	114	123	5 000	47	2 054
India	-	-	-	5 000	19	2 598
Japan	156	177	158	5 000	63	1 675
Middle East	-	-	-	5 000	25	2 563
North Africa	-	-	-	5 000	23	2 547
United States	70	100	108	5 000	31	2 425
Minimum	19	52	55	5 000	18	2 822
Maximum	171	177	178	5 000	63	1 675

## Methanation

Parameter	Units	Today	2030	Long term
CAPEX	USD/kW <sub>prod</sub>	845	735	565
Efficiency (LHV)	%	77	77	77
Annual OPEX	% of CAPEX	4	4	4
Lifetime	years	30	30	30
Electricity consumption	GJ <sub>e</sub> /GJ <sub>prod</sub>	0.013	0.013	0.013

## Fischer-Tropsch

Parameter	Units	Today	2030	Long term
CAPEX	USD/kW <sub>liquid</sub>	890	760	565
Efficiency (LHV)	%	73	73	73
Annual OPEX	% of CAPEX	4	4	4
Lifetime	years	30	30	30
Electricity consumption	GJ <sub>e</sub> /GJ <sub>liquid</sub>	0.018	0.018	0.018

## Ammonia (NH<sub>3</sub>)

Feedstock	Parameter	Units	Today	2030	Long term
Natural gas	CAPEX	USD/tNH <sub>3</sub>	905	905	905
	Annual OPEX	% of CAPEX	2.5	2.5	2.5
	Gas consumption	GJ/tNH <sub>3</sub>	42.0	38.3	32.2
	Electricity consumption	GJ/tNH <sub>3</sub>	0.3	0.3	0.3
	Emission factor	kgCO <sub>2</sub> /kgNH <sub>3</sub>	2.35	2.14	1.8
Natural gas w/CCUS	CAPEX	USD/tNH <sub>3</sub>	1 315	1 260	1 165
	Annual OPEX	% of CAPEX	2.5	2.5	2.5
	Gas consumption	GJ/tNH <sub>3</sub>	42.0	38.3	32.2

	Electricity consumption	GJ/t <sub>NH<sub>3</sub></sub>	1.3	1.3	1.3
	Emission factor	kgCO <sub>2</sub> /kgNH <sub>3</sub>	0.12	0.11	0.09
Coal	CAPEX	USD/tNH <sub>3</sub>	2 175	2 175	2 175
	Annual OPEX	% of CAPEX	5	5	5
	Coal consumption	GJ/tNH <sub>3</sub>	38.4	38.4	38.3
	Electricity consumption	GJ/tNH <sub>3</sub>	3.7	3.7	3.7
	Emission factor	kgCO <sub>2</sub> /kgNH <sub>3</sub>	3.9	3.9	3.9
Coal w/CCUS	CAPEX	USD/tNH <sub>3</sub>	2 810	2 810	2 810
	Annual OPEX	% of CAPEX	5	5	5
	Coal consumption	GJ/tNH <sub>3</sub>	38.4	38.4	38.3
	Electricity consumption	GJ/tNH <sub>3</sub>	5.3	5.3	5.3
	Emission factor	kgCO <sub>2</sub> /kgNH <sub>3</sub>	0.2	0.2	0.2
Biomass	CAPEX	USD/tNH <sub>3</sub>	6 320	6 320	6 320
	Annual OPEX	% of CAPEX	5	5	5
	Biomass consumption	GJ/tNH <sub>3</sub>	45.0	45.0	45.0
	Electricity consumption	GJ/tNH <sub>3</sub>	5.0	5.0	5.0
	Emission factor	kgCO <sub>2</sub> /kgNH <sub>3</sub>	0.0	0.0	0.0
Electrolysis	CAPEX	USD/tNH <sub>3</sub>	945	855	760
	Annual OPEX	% of CAPEX	1.5 %	1.5%	1.5%
	Electricity consumption	GJ/tNH <sub>3</sub>	37.8	35.3	33.2
	Emission factor	kgCO <sub>2</sub> /kgNH <sub>3</sub>	0.0	0.0	0.0

Notes: 25-year lifetime and 95% availability assumed for all equipment. CCUS options correspond to those capturing all emissions streams, and consider a 95% capture rate. The electrolysis route parameters include the electrolyser costs (see Hydrogen table). For major routes deployed, average energy performance is assumed today, tending towards best practice technology by 2050. Declining CAPEX/OPEX for CCUS options reflects the size of capture capacity required as the energy intensity improves. Emission factors correspond to net direct CO<sub>2</sub> emissions in the industrial sector.

## Methanol (MeOH)

Feedstock	Parameter	Units	Today	2030	Long term
Natural gas	CAPEX	USD/t <sub>MeOH</sub>	310	310	310
	Annual OPEX	% of CAPEX	2.5	2.5	2.5
	Gas consumption	GJ/t <sub>MeOH</sub>	33.9	33.0	31.5
	Electricity consumption	GJ/t <sub>MeOH</sub>	0.3	0.3	0.3
	Emission factor	kgCO <sub>2</sub> /kgMeOH	0.8	0.7	0.6
Natural gas w/CCUS	CAPEX	USD/t <sub>MeOH</sub>	525	510	490
	Annual OPEX	% of CAPEX	2.5	2.5	2.5
	Gas consumption	GJ/t <sub>MeOH</sub>	33.9	33.0	31.5
	Electricity consumption	GJ/t <sub>MeOH</sub>	0.7	0.7	0.6
	Emission factor	kgCO <sub>2</sub> /kgMeOH	0.04	0.04	0.03
Coal	CAPEX	USD/ t <sub>MeOH</sub>	750	750	750
	Annual OPEX	% of CAPEX	5	5	5
	Coal consumption	GJ/t <sub>MeOH</sub>	46.3	44.2	40.7
	Electricity consumption	GJ/t <sub>MeOH</sub>	3.7	3.7	3.7
	Emission factor	kgCO <sub>2</sub> /kg MeOH	3.3	3.1	2.7
Coal w/CCUS	CAPEX	USD/t <sub>MeOH</sub>	1 505	1 450	1 350
	Annual OPEX	% of CAPEX	5	5	5
	Coal consumption	GJ/t <sub>NH<sub>3</sub></sub>	55.3	52.5	47.8
	Electricity consumption	GJ/t <sub>NH<sub>3</sub></sub>	3.9	3.9	3.9
	Lifetime	years	25	25	25
	CO <sub>2</sub> capture rate	%	95	95	95

	Emission factor	kgCO <sub>2</sub> /kg MeOH	0.17	0.15	0.14
Biomass	CAPEX	USD/t <sub>MeOH</sub>	5 165	5 165	5 165
	Annual OPEX	% of CAPEX	5	5	5
	Biomass consumption	GJ/t <sub>NH<sub>3</sub></sub>	47.9	47.9	47.9
	Electricity consumption	GJ/t <sub>NH<sub>3</sub></sub>	5.0	5.0	5.0
Electrolysis	Emission factor	kgCO <sub>2</sub> /kgNH <sub>3</sub>	0.0	0.0	0.0
	CAPEX	USD/t <sub>MeOH</sub>	790	595	380
	Annual OPEX	% of CAPEX	1.5	1.5	1.5
	Electricity consumption	GJ/t <sub>MeOH</sub>	25.4	23.7	22.2
	Emission factor	kgCO <sub>2</sub> /kgNH <sub>3</sub>	0.0	0.0	0.0

Notes: 25-year lifetime and 95% availability assumed for all equipment. CCUS options correspond to those capturing all emissions streams, and consider a 95% capture rate. The electrolysis route parameters include the electrolyser costs (see Hydrogen table). For major routes deployed, average energy performance is assumed today, tending towards best practice technology by 2050. Declining CAPEX/OPEX for CCUS options reflects the size of capture capacity required as the energy intensity improves. Emission factors correspond to net direct CO<sub>2</sub> emissions in the industrial sector. CO<sub>2</sub> feedstock for the electrolysis route is assumed to be available at zero cost.

# Transmission, distribution and storage

## Transmission

Technology	Parameter	Units	Hydrogen	LOHC	Ammonia	
Pipelines <sup>1</sup>	Lifetime	years	40	-	40	
	Distance	km	Function of supply route			
	Design throughput	ktH <sub>2</sub> /y	GH <sub>2</sub> : 340	800	240	
	Gas density	kg/m <sup>3</sup>	7.9	-	-	
	Gas velocity	m/s	15	-	-	
	CAPEX/km	USD million/km	1.21	2.32	0.55	
	Utilisation	%	75%	75%	75%	
	Liquefaction	Installed capacity	ktH <sub>2</sub> /y	260	-	-
		Capacity CAPEX	USD million	1 400	-	-
		Annual OPEX	% of CAPEX	4%	-	-
Electricity use		kWh/kgH <sub>2</sub>	6.1	-	-	
Conversion <sup>2</sup>	Installed capacity	kt <sub>Tol</sub> /y	-	4 200	-	
	Plant CAPEX	USD million	-	230	-	
	Annual OPEX	% of CAPEX	-	4%	-	
	Electricity use	kWh/kgH <sub>2</sub>	-	1.5	-	
	Natural gas use	kWh/kgH <sub>2</sub>	-	0.2	-	
	Start-up toluene	kt	-	260	-	
	Toluene cost	USD/t <sub>Tol</sub>	-	400	-	
Export terminal	Toluene markup	kt <sub>Tol</sub> /y	-	100	-	
	Capacity/tank	tH <sub>2</sub> or t <sub>Tol</sub> or t <sub>NH<sub>3</sub></sub>	3 190	51 750	34 100	
	No. of tanks		Based on days of storage needed for a given ship loading frequency			
	CAPEX/tank	USD million	290	42	68	
	Annual OPEX	% of CAPEX	4%	4%	4%	
	Electricity use	kWh/kgH <sub>2</sub>	0.61	0.01	0.005	
	Boil off rate	%/day	0.1%	-	-	
	Flash rate	%	0.1%	-	-	
	Seaborne transport <sup>3</sup>	Capacity/ship	tH <sub>2</sub> or t <sub>Tol</sub> or t <sub>NH<sub>3</sub></sub>	11 000	110 000	53 000
		CAPEX/ship	USD million	412	76	85
		Ship speed	km/h	30	30	30
		No. of ships used		Function of distance		
		Annual OPEX	% of CAPEX	4	4	4
Fuel use		MJ/km	1 487 <sup>4</sup>	3 300	2 500	
Import terminal	Boil-off rate	%/day	0.2%	-	-	
	Flash rate	%	1.3%	-	-	
	Capacity/tank	tH <sub>2</sub> or t <sub>Tol</sub> or t <sub>NH<sub>3</sub></sub>	3 550	61 600	56 700	
	No. of tanks	#	Based on 20 days of storage capacity			
	CAPEX/tank	USD million	320	35	97	
	Electricity use	kWh/kgH <sub>2</sub>	0.2	0.01	0.02	
	Boil-off rate	%/day	0.1	-	-	
Reconversion <sup>4</sup>	Capacity	kt <sub>Tol</sub> /y or kt <sub>NH<sub>3</sub></sub> /y	-	4 200	1 500	

Capacity CAPEX	USD million	-	670	460
Annual OPEX	% of CAPEX	-	4%	4%
Heat required	kWh/kgH <sub>2</sub>	-	13.6	9.7
Plant power	kWh/kgH <sub>2</sub>	-	0.4	-
H <sub>2</sub> purification (PSA) power	kWh/kgH <sub>2</sub>	-	1.1	1.5
H <sub>2</sub> recovery rate	%	-	90%	99%
PSA H <sub>2</sub> recovery rate	%	-	98%	85%

Notes: GH<sub>2</sub> = gaseous hydrogen. PSA = Pressure swing adsorption. System lifetime assumed to be 30 years, unless stated otherwise; discount rate = 8%; utilisation of production, conversion and reconversion capacity = 90%.

<sup>1</sup> Transmission pipeline for hydrogen gas based on Baufumé (2013): Pipeline CAPEX (USD/km) = 4 000 000D<sup>2</sup> + 598 600D + 329 000; where D (internal diameter in cm) =  $\sqrt{(F/v)/\pi \cdot 2 \cdot 100}$ ; v = gas velocity (m/s); F (volumetric flow in m<sup>3</sup>/s) = Q/ρ; Q = gas throughput (kg/s); ρ = gas density (kg/m<sup>3</sup>). Based on real gas law (pressure = 100 bar).

<sup>2</sup> Conversion: LOHC = Toluene + H<sub>2</sub> → MCH. Toluene mark-up is the quantity of new toluene required reach year. Data for ammonia conversion are included in the table on ammonia above.

<sup>3</sup> Ship carrying liquid hydrogen uses boil-off gas for propulsion; LOHC and ammonia ship uses heavy fuel oil. It is assumed that fuel consumption can be obtained from boil-off losses in the storage tank, so the fuel for the ship would not incur an additional energy penalty.

<sup>4</sup> Reconversion: LOHC = MCH → Toluene + H<sub>2</sub>; Ammonia = NH<sub>3</sub> → N<sub>2</sub> + H<sub>2</sub>.

Sources: Baufumé et al. (2013), "GIS-based scenario calculations for a nationwide German hydrogen pipeline infrastructure"; IAE (2019), "Institute of Applied Energy (Japan) data based on revisions from Economical Evaluation and Characteristic Analyses for Energy Carrier Systems (FY 2014–FY 2015) Final Report"; ETSAP (2011), *LOHC Ship Cost from: Oil and Natural Gas Logistics*; IMO (2014), *Third IMO Greenhouse Gas Study 2014*.

## Distribution

Technology	Parameter	Units	Hydrogen	LOHC	Ammonia
Pipelines	Lifetime	years	40	40	40
Pipelines (high pressure) <sup>1</sup>	Inlet pressure	bar	80	-	-
	Distance	km	End use case dependent		
	Design throughput (Q)	ktH <sub>2</sub> /y	38	-	-
	Gas density (ρ)	kg/m <sup>3</sup>	6.4	-	-
	Gas velocity (v)	m/s	15	-	-
	CAPEX	USD million/km	0.5	1	0.25
	Pipelines (low pressure) <sup>2</sup>	Distance	km	3	3
Design throughput (Q)		t/y	GH <sub>2</sub> : 365	-	-
Gas density (ρ)		kg/m <sup>3</sup>	0.55	-	-
Gas velocity (v)		m/s	15	-	-
CAPEX/km		USD million/km	0.3	-	-
Trucks <sup>3</sup>	Depreciation period	years	12	12	12
	CAPEX	USD thousand	185	185	185
	Annual OPEX	% of CAPEX	12	12	12
	Speed	km/h	50	50	50
	Driver cost	USD/h	23	23	23
Trailers	Depreciation period	years	12	12	20
	CAPEX	USD thousand	LH <sub>2</sub> : 1 000 GH <sub>2</sub> : 650	170	220
	Annual OPEX	% of CAPEX	2%	2%	2%
	Net capacity	kgH <sub>2</sub>	LH <sub>2</sub> : 4300 GH <sub>2</sub> : 670	1 800	2 600



	Loading/unloading time	hrs	LH <sub>2</sub> : 3 GH <sub>2</sub> : 1.5	1.5	1.5
H <sub>2</sub> refuelling stations <sup>4</sup>	Station lifetime	yrs	10	10	10
	Station size	kg/day	1 000	1 000	1 000
	CAPEX	USD million	See road transport	3.5	2.2
	OPEX as % of CAPEX	%	5%	5%	5%
	Electricity demand	kWh/kgH <sub>2</sub>	LH <sub>2</sub> : 0.6 GH <sub>2</sub> : 1.6	4.4	10.8
	Heat demand	kWh/kgH <sub>2</sub>	0	13.6	0
	Boil off	% of total weight	LH <sub>2</sub> : 3% GH <sub>2</sub> : 0.5%	0.5%	1.5%
	Utilisation	%	50%	50%	50%

Note: LH<sub>2</sub> = liquid hydrogen.

<sup>1</sup> Distribution pipeline for hydrogen gas based on Baufumé (2013): Pipeline CAPEX (USD/km) = 3 400 000D<sup>2</sup> + 598 600D + 329 000 (Baufumé, 2013); where D (internal diameter in cm) =  $\sqrt{(F/v)/\pi \cdot 2 \cdot 100}$ ; v = gas velocity (m/s); F (volumetric flow in m<sup>3</sup>/s) = Q/ρ; Q = gas throughput (kg/s); ρ = gas density (kg/m<sup>3</sup>) (high-pressure pipeline = 80 bar; low-pressure pipeline = 7 bar).

<sup>2</sup> Pipeline with lower throughput to hydrogen refuelling stations, taking partial flow from high-pressure distribution pipe.

<sup>3</sup> Journey distance doubled to account for journey time and fuel cost calculations, and loading time for LOHC should be doubled for toluene being returned to site of origin.

<sup>4</sup> H<sub>2</sub> refuelling station in the case of LOHC and ammonia includes costs for LOHC and ammonia reconversion technology, electricity and natural gas for heat. CAPEX for large fuel cell station (1 000 kg/day) scaled up from small size reference station receiving compressed hydrogen gas according to CAPEX = X\*Y\*γ(Z/α)<sup>β</sup>. X = reference station cost (EUR 600 000); Y = installation factor (1.3); γ = station multiplier (LH<sub>2</sub> = 0.9, GH<sub>2</sub> = 0.6, LOHC = 1.4, ammonia = 1.4); α = reference station size (210 kg/day); and β = scaling factor (LH<sub>2</sub> = 0.6, GH<sub>2</sub> = 0.7, LOHC = 0.66, ammonia = 0.6).

Sources: Baufumé et al. (2013), "GIS-based scenario calculations for a nationwide German hydrogen pipeline infrastructure"; Reuß et al. (2017), "Seasonal storage and alternative carriers: A flexible hydrogen supply chain model"; Reuß et al. (2019), "A hydrogen supply chain with spatial resolution: Comparative analysis of infrastructure technologies in Germany".

## Industrial applications

### Steel

Route	Parameter	Units	Today	2030	Long term
BF-BOF	CAPEX	USD/t <sub>crude steel</sub>	600	600	600
	Annual OPEX	% of CAPEX	23	23	23
	Electricity consumption	GJ/t <sub>crude steel</sub>	0.7	0.7	0.7
	Coal consumption	GJ/t <sub>crude steel</sub>	18.0	18.0	18.0
Natural gas-based DRI-EAF	Natural gas consumption	GJ/t <sub>crude steel</sub>	1.0	1.0	1.0
	CAPEX	USD/t <sub>crude steel</sub>	590	590	590
	Annual OPEX	% of CAPEX	25	25	25
	Electricity consumption	GJ/t <sub>crude steel</sub>	2.5	2.5	2.5
Natural gas-based DRI-EAF w/CCUS	Coal consumption	GJ/t <sub>crude steel</sub>	0.5	0.5	0.5
	Natural gas consumption	GJ/t <sub>crude steel</sub>	10.1	10.1	10.1
	CAPEX	USD/t <sub>crude steel</sub>	640	640	640
	Annual OPEX	% of CAPEX	23	23	23
Hydrogen-based DRI-EAF	Electricity consumption	GJ/t <sub>crude steel</sub>	2.7	2.7	2.7
	Coal consumption	GJ/t <sub>crude steel</sub>	0.5	0.5	0.5
	Natural gas consumption	GJ/t <sub>crude steel</sub>	10.1	10.1	10.1
	CAPEX	USD/t <sub>crude steel</sub>	945	855	755
Oxygen-rich smelt reduction w/CCUS	Annual OPEX	% of CAPEX	16	18	20
	Electricity consumption	GJ/t <sub>crude steel</sub>	14.7	13.9	13.2
	Biomass consumption	GJ/t <sub>crude steel</sub>	1.9	1.9	1.9
	CAPEX	USD/t <sub>crude steel</sub>	530	530	530
Oxygen-rich smelt reduction w/CCUS	Annual OPEX	% of CAPEX	17	17	17
	Electricity consumption	GJ/t <sub>crude steel</sub>	3.5	3.5	3.5
	Coal consumption	GJ/t <sub>crude steel</sub>	12.1	12.1	12.1

Notes: 25-year lifetime and 95% availability assumed for all equipment. Capture rate of 95% assumed for CCUS routes. Hydrogen-based DRI-EAF parameters include the electrolyser costs (see Hydrogen table). The hydrogen requirement for this route is estimated to lie in the range of 47-68 kg/t of DRI, with the mid-point of this range used for the cost calculations. For the DRI-EAF routes, a 95% charge of DRI to the EAF is considered. An iron ore (58% Fe content) cost of USD 60/t and a scrap cost of USD 260/t is assumed for all process routes, regions and time periods. Costs of electrodes, alloys and other wearing components are considered as a part of the fixed OPEX.

### Transport vehicles

Powertrain	Parameter	Units	Cars	Trucks	Ships
-	Mileage	km/yr	15 000	100 000	100 000
-	Lifetime	years	5	5	15
-	Discount rate	%	10	10	10
-	Glider	USD thousand	23	117.5	35 000
-	Salvage value	% <sup>1</sup>	43	41.8	0
-	Power	kW	95	350	10 989
FCEV	Fuel cell cost	USD/kW	200 / 50 <sup>2</sup>	250 / 95	2 000 / 1 000
	Hydrogen tank	USD/kWh	15 / 9	15 / 9	18 / 9

	Battery	kWh	2	3.3	-
	Fuel consumption	MJ/km	1.36	7.8	1 487 / 1 770
	Electric motor	USD/kW	14	39	70
	O&M	USD/km	0.0776	0.106	-
	Delivered H <sub>2</sub> price	USD/kg	9.2 / 5	7.3 / 5	3.6 / 3.8 <sup>3</sup>
Hydrogen refuelling station <sup>4</sup>	Size	kg/day	200 / 1 000	500 / 1 300	Based on LNG <sup>5</sup>
	CAPEX	USD million	0.9 / 1.8	1.2 / 2.1	
	Utilisation	%	10 / 33	10 / 40	-
BEV <sup>6</sup>	Battery cost	USD/kWh	200 / 100	200 / 100	
	Battery size <sup>7</sup>	kWh	100	850	-
	Fuel consumption	MJ/km	0.75	5.1	-
	O&M	USD/km	0.065	0.106	-
	Base electricity price <sup>8</sup>	USD/kWh	0.12	0.12	-
ICE <sup>9</sup>	Fuel consumption	MJ/km	2.7	11.7	1 715
	Motor	USD/kW	30	118	216 / 650 <sup>10</sup>
	Fuel tank	USD/kWh			
	O&M	USD/km	0.08	0.16	-
ICE - Hybrid	Fuel consumption	MJ/km	1.6	10.9	-
	O&M	USD/km	0.078	0.16	-

Note: O&M = operation and maintenance. For ships, engine efficiency is assumed to be 50% for ICEs, 60% for fuel cells, and 95% for electric motors. A 20% margin (between costs and prices) is assumed for all vehicle components on all powertrains, including the glider. Current ammonia price (using SMR with CCS) is USD 460/tonne; the future price (using electrolysis) is USD 355/tonne. The synthetic fuel cost is USD 260/tonne today and USD 140/tonne in the future. Bulk carriers come in a wide range of sizes, from small ships of only a few hundred tonnes deadweight (the total weight that a ship can carry) to over 360 000 tonnes. The bulk carrier considered here is comparable to a Panamax ship with a length of 200–230 metres, a draft of 13–15 metres and a beam close to 30 metres. For all vehicle types, depreciation is set at representative values, and is assumed to be the same for all powertrains.

<sup>1</sup> Percentage of total vehicle cost (CAPEX) equivalent to the glider and powertrain-specific components.

<sup>2</sup> Where there are two values in a single cell they refer to current and long-term values respectively.

<sup>3</sup> The current hydrogen price for ships is USD 3.6/kgH<sub>2</sub> (assuming low-cost gas with CCUS) and the long term price is USD 3.8/kgH<sub>2</sub> (assuming the it is produced via electrolysis, in the regions with the lowest production costs)

<sup>4</sup> HRS and charging infrastructure (including catenary lines) are assumed to have an economic lifetime of 30 years.

<sup>5</sup> LNG figures from (Danish Maritime Authority, 2012) and (Faber 2017) with the ratio between hydrogen and LNG from (Taljegard et al., 2014)

<sup>6</sup> Slow charger (4 kW) cost is USD 650, fast public charger (47 kW) cost is USD 33 000. Cars assume a 50/50 split between these two. Tesla mega charger (1 600 kW), with a cost of USD 220 000, is used for trucks.

<sup>7</sup> Battery size is proportional to vehicle range. Values shown are for 500 km.

<sup>8</sup> Base electricity price does not include additional costs of installing and operating dedicated charging infrastructure

<sup>9</sup> ICE technologies refer to gasoline for cars, diesel for trucks and very low sulphur fuel oil for ships.

<sup>10</sup> The first value refers to very low sulphur fuel oil, the second value to hydrogen and ammonia.

Sources: US DOE (2019), "Fuel Cell R&D Overview"; IEA (2019a), *Global EV Outlook 2019: Overcoming The Challenges Of Transport Electrification*; IEA (2019b). *Mobility Model*; sources for hydrogen refuelling station as per Figure 4 in Chapter 5.

## Large-scale and long-term storage

Parameter	Units	Long-term characterisation of storage technology options				
		PHES	CAES	Li-Ion battery	Compressed hydrogen	Ammonia
CAPEX – power-related	USD/kW <sub>e</sub>	1 130	870	95	1 820	2 840
CAPEX – energy-related	USD/kWh	80	39	110	0.25	0.3
OPEX power-related	USD/kW <sub>e</sub>	8	4	10	73	43
OPEX energy-related	USD/kWh	1	4	3	0	0
Round-trip efficiency	%	78	44	86	37	22
Lifetime	years	55	30	13	20	20

Sources: Element Energy (2018), "Hydrogen supply chain evidence base"; ETI (2018), "Salt cavern appraisal for hydrogen and gas storage"; Northern Gas Networks (2018), *H21 North of England*; Kruck et al. (2013), "Overview on all known underground storage technologies for hydrogen"; Roberts, Dolan and Harris (2018), "Role of carbon resources in emerging hydrogen energy systems"; Schmidt et al. (2019), "Projecting the future levelized cost of electricity storage technologies"; Tzimas et al. (2003), "Hydrogen storage: State-of-the-art and future perspective".

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