



# Feasibility and potential of e-methane in the future energy mix

Appendix

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# Contents

This document serves as an appendix to the main report *Feasibility and potential of e-methane in the future energy mix*. The document details all the assumptions made and additional analysis carried out during the study

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## A. Assumptions

# In this section, assumptions used in the model have been detailed, including their source and comfort level

Explanation of the layout of the assumption section



Category	Parameter	Units	Liquefied Methane			Ammonia			Methanol		
			Value	Source	Comfort level	Value	Source	Comfort level	Value	Source	Comfort level
Stoichiometry	Fuel Consumption	MJ/ton/km	0 <sup>1)</sup>	Agora <sup>XXIII</sup>	●	0.05	IEA <sup>XLIV</sup>	●	0.03 <sup>2)</sup>	Assumed	●
	Losses	%	<0.5%	Assumed	●	0.02%	IEA <sup>XLIV</sup>	●	0%	HyDelta <sup>XLVI</sup>	●
	Boiloff Losses	%/day	0.2%	Agora <sup>XXIII</sup>	●	0.02%	IEA <sup>XLIV</sup>	●	0%	HyDelta <sup>XLVI</sup>	●
Asset specifics	CAPEX	EUR/ton	2,834	Agora <sup>XXIII</sup>	●	1,351	IEA <sup>XLIV</sup>	●	515	HyDelta <sup>XXXIII</sup>	●
	OPEX	% of total CAPEX	4 <sup>3)</sup>	Agora <sup>XXIII</sup>	●	4 <sup>3)</sup>	Agora <sup>XXIII</sup>	●	5 <sup>3)</sup>	HyDelta <sup>XXXIII</sup>	●
	Fuel type	-	LNG <sup>4)</sup>	Agora <sup>XXIII</sup>	●	e-NH3	IEA <sup>XLIV</sup>	●	e-MeOH	Assumed	●
	Storage tank cap.	kt of carrier	76	Agora <sup>XXIII</sup>	●	52	IEA <sup>XLIV</sup>	●	95	HyDelta <sup>XXXIII</sup>	●
	Lifetime	years	30	Assumed	●	30	HyDelta <sup>XLVI</sup>	●	30	HyDelta <sup>XLVI</sup>	●
	Utilization	% of usage/year	91%	Agora <sup>XXIII</sup>	●	91%	Agora <sup>XXIII</sup>	●	91%	Agora <sup>XXIII</sup>	●
	Speed	km/h	30	Agora <sup>XXIII</sup>	●	32	IEA <sup>XLIV</sup>	●	33	HyDelta <sup>XXXIII</sup>	●
	Suez Canal fee <sup>5)</sup>	EUR m	0.9	Assumed	●	0.7	IRENA <sup>XLVII</sup>	●	1.1	Assumed	●
Port fees <sup>6)</sup>	EUR k	<215	Ports <sup>XLVIII)(XLIX)(L)(LI)</sup>	●	<200	Ports <sup>XLVIII)(XLIX)(L)(LI)</sup>	●	<225	Ports <sup>XLVIII)(XLIX)(L)(LI)</sup>	●	
Scope 1 Emissions	CO <sub>2</sub> , NO <sub>x</sub> , N <sub>2</sub> O	kg of CO <sub>2</sub> e/MWh	Corresponding to combustion of LNG/unloading losses			Corresponding to combustion of NH <sub>3</sub>			Corresponding to MeOH combustion		
	CH <sub>4</sub>	kg of CO <sub>2</sub> e/MWh	not applicable			not applicable			not applicable		
	H <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable			not applicable			not applicable		

**High** Applicable to the values of technologies that are currently mature, with substantial supporting data available in public literature

**Medium** Applicable to the values of technologies with moderate maturity where uncertainty exists about future advancements. In this study, 2040 values are based on optimistic advancements in technology. In some cases, also applicable for values of mature technologies for which sufficient public data is unavailable

**Low** Applicable to the values of technologies in the early stages of development, where higher uncertainties exist about future advancements and cost estimates

Parameters are categorized based on the vector's stoichiometry, asset-specific characteristics, and associated emissions

Units for each parameter and associated values based on 2040 technology status

Source for each assumption (Latin numerals correspond to exact sources listed at end of the section)

Comfort level on the assumption

# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: General

Parameter	Units	Methane [Natural gas]		Hydrogen		Ammonia		Methanol		LOHC	
		Value	Source	Value	Source	Value	Source	Value	Source	Value	Source
kg to ton	[t/kg]	1,000	-	1,000	-	1,000	-	1,000	-	1,000	-
GJ to kWh	[kWh/GJ]	277.77	-	277.77	-	277.77	-	277.77	-	277.77	-
MJ to kWh	[kWh/MJ]	0.278	-	0.278	-	0.278	-	0.278	-	0.278	-
kWh to MJ	[MJ/kWh]	3.6	-	3.6	-	3.6	-	3.6	-	3.6	-
mmBTU to MWh	[-]	0.29	-	0.29	-	0.29	-	0.29	-	0.29	-
42-gallon barrel to liter	[liter/42-gallon barrel]	159	-	159	-	159	-	159	-	159	-
mcf to MWh	[MWh/mcf]	0.29	NRG <sup>1)</sup>	0.29	NRG <sup>1)</sup>	0.29	NRG <sup>1)</sup>	0.29	NRG <sup>1)</sup>	0.29	NRG <sup>1)</sup>
m <sup>3</sup> to ton	[ton /m <sup>3</sup> ]	0.4	Cetiner <sup>II)</sup>	-	-	-	-	-	-	-	-
Lower heating value (LHV)	[MJ/m <sup>3</sup> ]	35.8 [31.7 <sup>1)</sup>	Engineering toolbox <sup>III)</sup> TU Delft <sup>IV)</sup>	-	-	-	-	-	-	-	-
Lower heating value (LHV)	[kWh/kg]	13.9 [10.6 <sup>1)</sup>	Engineering toolbox <sup>III)</sup> TU Delft <sup>IV)</sup>	33.33	Engineering toolbox <sup>III)</sup>	5.2	Engineering toolbox <sup>III)</sup>	5.5	Engineering toolbox <sup>III)</sup>	2.0	Deutscher Bundestag <sup>V)</sup>

Comfort level of the assumption: ● High ● Medium ● Low

1) Based on Groningen/ North-sea gas

# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: Emissions

Parameter	Units	CO <sub>2</sub>		CH <sub>4</sub>		N <sub>2</sub> O		NO <sub>x</sub>		H <sub>2</sub>	
		Value	Source	Value	Source	Value	Source	Value	Source	Value	Source
Global Warming Potential for 100 years	[kg of CO <sub>2e</sub> /kg]	1	-	27	IPCC <sup>(vi)</sup>	273	IPCC <sup>(vi)</sup>	8.5	Lammel & Graßl <sup>(vii)</sup>	11.6	Sand et al. <sup>(viii)</sup>
Emissions from natural gas/methane combustion	[kg/kg]	2.69	US NETL <sup>(ix)</sup>	<0.1	US NETL <sup>(ix)</sup>	<0.1	US NETL <sup>(ix)</sup>	0	US NETL <sup>(ix)</sup>	0	US NETL <sup>(ix)</sup>
Emissions from ammonia combustion	[g/kWh]	0	Zero Carbon Shipping <sup>(x)</sup>	0	Zero Carbon Shipping <sup>(x)</sup>	0.1	Zero Carbon Shipping <sup>(x)</sup>	2.0	Zero Carbon Shipping <sup>(x)</sup>	0.0	Zero Carbon Shipping <sup>(x)</sup>
Emissions from methanol combustion	[g/MJ]	69.0	DNV <sup>(xi)</sup>	0.0	DNV <sup>(xi)</sup>	0.0	DNV <sup>(xi)</sup>	0.4	DNV <sup>(xi)</sup>	0.0	DNV <sup>(xi)</sup>
Emissions from hydrogen combustion	[g/kg]	0.0	EU LCA <sup>(xii)</sup>	0.0	EU LCA <sup>(xii)</sup>	0.0	EU LCA <sup>(xii)</sup>	6.8	EU LCA <sup>(xii)</sup>	0.0	EU LCA <sup>(xii)</sup>

Comfort level of the assumption: ● High ● Medium ● Low

# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: Feedstock

Parameter	Units	US		Middle East		Southern Europe		Northern Europe	
		Value	Source	Value	Source	Value	Source	Value	Source
Grid electricity price	[EUR/MWh]	71	EIA <sup>xiii</sup>	41	Assumed	73	VBW <sup>xiv</sup>	58 [NL:92]	VBW <sup>xiv</sup> , E-bridge <sup>xv</sup>
Grid intensity	[ton of CO <sub>2</sub> /MWh]	0.05	IEA <sup>xvi</sup>	0.21	Enerdata <sup>xvii</sup>	0.03	IEA <sup>xvi</sup>	0.03	IEA <sup>xvi</sup>
Digestion feedstock price	[EUR/ton]	60	CE Delft <sup>xviii</sup>	60	CE Delft <sup>xviii</sup>	60	CE Delft <sup>xviii</sup>	60	CE Delft <sup>xviii</sup>
CO <sub>2</sub> price from DAC	[EUR/ton]	136	Natuur & Milieu <sup>xix</sup>	106	Natuur & Milieu <sup>xix</sup>	138	Natuur & Milieu <sup>xix</sup>	123	Natuur & Milieu <sup>xix</sup>
CO <sub>2</sub> price from biogenic byproduct	[EUR/ton]	29	US NETL <sup>xx</sup>	26	US NETL <sup>xx</sup>	30	US NETL <sup>xx</sup>	28	US NETL <sup>xx</sup>
CO <sub>2</sub> price from fossil/biogenic point source	[EUR/ton]	59	US NETL <sup>xx</sup>	49	US NETL <sup>xx</sup>	59	US NETL <sup>xx</sup>	54	US NETL <sup>xx</sup>
Green Hydrogen production efficiency	[%]	76%	IEA <sup>xxi</sup>	76%	IEA <sup>xxi</sup>	76%	IEA <sup>xxi</sup>	76%	IEA <sup>xxi</sup>
Levelized cost of renewable Hydrogen	[EUR/kg]	2.5	IEA <sup>xxi</sup>	2.5	IEA <sup>xxi</sup>	2.8	IEA <sup>xxi</sup>	3	IEA <sup>xxi</sup>
LOHC (DBT) price	[EUR/kg]	1.6	HySTOC <sup>xxii</sup>	1.6	HySTOC <sup>xxii</sup>	1.6	HySTOC <sup>xxii</sup>	1.6	HySTOC <sup>xxii</sup>

Comfort level of the assumption: ● High ● Medium ● Low

1) We assume the same CO<sub>2</sub> tax for US and Middle East, as CBAM will ensure the carbon price of imports is equivalent to the carbon price of domestic production

# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: Conversion/extraction (1/2)



Primary energy production

Category	Parameter	Units	Natural Gas		E-Methane		Biomethane via Anaerobic Digestion	
			Value	Source	Value	Source	Value	Source
Stoichiometry	H <sub>2</sub>	ton/ton			0.50	Agora <sup>xxiii)</sup>		
	CO <sub>2</sub>	ton/ton			2.69	Agora <sup>xxiii)</sup>		not applicable
	N <sub>2</sub>	ton/ton		not applicable				
	Digestion input	ton/ton				not applicable	4.12	CE Delft <sup>xviii)</sup>
	Electricity	MWh/ton			0.05	Agora <sup>xxiii)</sup>	0.69	CE Delft <sup>xviii)</sup>
	Fuel <sup>1)</sup>	MWh/ton	0.07	US NETL <sup>(x)</sup>		not applicable	0.70	CE Delft <sup>xviii)</sup>
Asset specifics	CAPEX	EUR m/MW	6.4 <sup>2)</sup>	EUR/MWh, Canadian Energy Center <sup>xxiv)</sup>	0.5	IEA <sup>xxv)</sup>	1.5	BIP <sup>xxvi)</sup>
	OPEX	% of total CAPEX			4% <sup>3)</sup>	IEA <sup>xxv)</sup>	10%	BIP <sup>xxvi)</sup>
	Lifetime	years	30	Assumed	30	IEA <sup>xxvii)</sup>	25	Navigant <sup>xxviii)</sup>
	Utilization	% of 8,760 FLH	95%	Assumed	95%	IEA <sup>xxv)</sup>	95%	Assumed
	Capacity	MW		not needed	500	S&P Global <sup>xxix)</sup>	8	Engie <sup>xxx)</sup>
Scope 1 Emissions	CO <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	12.5	US NETL <sup>(x)</sup>	0	Assumed	0	Assumed
	CH <sub>4</sub>	kg of CO <sub>2</sub> e/MWh	29.2	US NETL <sup>(x)</sup>	0	EU LCA <sup>xii)</sup>	10	IEA Bioenergy <sup>xxxi)</sup>
	N <sub>2</sub> O	kg of CO <sub>2</sub> e/MWh	<0.01	US NETL <sup>(x)</sup>		not applicable	0	Assumed
	NO <sub>x</sub>	kg of CO <sub>2</sub> e/MWh		not applicable				not applicable
	H <sub>2</sub>	kg of CO <sub>2</sub> e/MWh		not applicable	7.5	Navajas et al. <sup>xxxi)</sup>		not applicable

1) Figure depicts combustion of the respective energy vector in the production step; 2) Number incorporate producing, under development and discovery phases of natural gas production; 3) Figure only covers fixed OPEX, excl. feedstock prices;

Source: US NETL, Canadian Energy Center, Exxon Mobile, IEA, CE Delft

Comfort level of the assumption: ● High ● Medium ● Low

# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: Conversion/extraction (2/2)



Category	Parameter	Units	Ammonia		Methanol		LOHC (DBT)	
			Value	Source	Value	Source	Value	Source
Stoichiometry	H <sub>2</sub>	ton/ton	0.18	Agora <sup>xxxiii)</sup>	0.20	HyDelta <sup>xxxiii)</sup>	0.06	HySTOC <sup>xxii)</sup>
	CO <sub>2</sub>	ton/ton	not applicable		0.07	HyDelta <sup>xxxiii)</sup>	not applicable	
	N <sub>2</sub>	ton/ton	0.82	Agora <sup>xxxiii)</sup>	not applicable		not applicable	
	DBT-HO	ton/ton	not applicable		not applicable		0.94	EU LCA <sup>xii)</sup>
	Electricity	MWh/ton	0.65 <sup>1)</sup>	IRENA <sup>xxxiv)</sup>	0.20	HyDelta <sup>xxxiii)</sup>	0.02	EU LCA <sup>xii)</sup>
	Fuel <sup>2)</sup>	MWh/ton	not applicable		not applicable		not applicable	
Asset specifics	CAPEX	EUR/ton	283	IRENA <sup>xxxiv)</sup>	158	HyDelta <sup>xxxiii)</sup>	21	IRENA <sup>xxxiv)</sup>
	OPEX <sup>3)</sup>	% of total CAPEX	3%	IRENA <sup>xxxiv)</sup>	2.7%	HyDelta <sup>xxxiii)</sup>	1.5%	HySTOC <sup>xxii)</sup>
	Lifetime	years	30	Assumed	30	Assumed	30	Assumed
	Utilization	% of 8,760 FLH	95 %	Assumed	95%	Assumed	95%	Assumed
	Capacity	kt/year	1,825	IRENA <sup>xxxiv)</sup>	475	HyDelta <sup>xxxiii)</sup>	329	IRENA <sup>xxxiv)</sup>
Scope 1 Emissions	CO <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		0	Assumed	not applicable	
	CH <sub>4</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		not applicable		not applicable	
	N <sub>2</sub> O	kg of CO <sub>2</sub> e/MWh	not applicable		not applicable		not applicable	
	NO <sub>x</sub>	kg of CO <sub>2</sub> e/MWh	1.6	EU LCA <sup>xii)</sup>	not applicable		not applicable	
	H <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	1.7	EU LCA <sup>xii)</sup>	0.4	EU LCA <sup>xii)</sup>	0.36	EU LCA <sup>xii)</sup>

1) Electricity consumption includes nitrogen separation from air; 2) Figure depicts combustion of the respective energy vector in the production step; 3) Figure only covers fixed OPEX, excl. feedstock prices

# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: Preparing for transport



Category	Parameter	Units	E-Methane <sup>1)</sup> compression		E-Methane <sup>1)</sup> liquefaction		Hydrogen compression		Hydrogen liquefaction	
			Value	Source	Value	Source	Value	Source	Value	Source
Stoichiometry	Electricity input	MWh/ton	0.28	Sterner et al. <sup>xxxv)</sup>	0.48	Agora <sup>xxiii)</sup>	0.52	HyDelta <sup>xxxiii)</sup>	6.0	IRENA <sup>xxxiv)</sup>
	Losses	%	0.15%	US NETL <sup>ix)</sup>	0.1%	Agora <sup>xxiii)</sup>	0.5%	HyDelta <sup>xxxiii)</sup>	2%	EU LCA <sup>xii)</sup>
Asset specifics	CAPEX	EUR/ton	0.1	EUR/MWh, Oxford Inst. <sup>xxxvi)</sup>	750	Zhang et al. <sup>xxxvii)</sup>	180	HyDelta <sup>xxxiii)</sup>	2,915	IRENA <sup>xxxiv)</sup>
	OPEX	% of total CAPEX			2.5% <sup>2)</sup>	Oxford Inst. <sup>xxxvi)</sup>	4% <sup>2)</sup>	HyDelta <sup>xxxiii)</sup>	4% <sup>2)</sup>	Agora <sup>xxiii)</sup>
	Lifetime	years	15	Assumed	30	Appea <sup>xxxviii)</sup>	15	HyDelta <sup>xxxiii)</sup>	30	Assumed
	Utilization	% of 8,760 FLH	85%	Assumed	95%	Assumed	85%	HyDelta <sup>xxxiii)</sup>	95%	HyDelta <sup>xxxiii)</sup>
	Capacity	kt	not needed		32,000	Zhang et al. <sup>xxxvii)</sup>	14	HyDelta <sup>xxxiii)</sup>	73	IRENA <sup>xxxiv)</sup>
Scope 1 Emissions	CO <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable <sup>3)</sup>		not applicable <sup>3)</sup>		not applicable		not applicable	
	CH <sub>4</sub>	kg of CO <sub>2</sub> e/MWh	Corresponding to losses		Corresponding to losses		not applicable		not applicable	
	N <sub>2</sub> O	kg of CO <sub>2</sub> e/MWh	not applicable		not applicable		not applicable		not applicable	
	NO <sub>x</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		not applicable		not applicable		not applicable	
	H <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		not applicable		Corresponding to losses		Corresponding to losses	

1) Input also valid for biomethane and fossil natural gas; 2) Value only comprises fixed OPEX, excl. feedstock costs; 3) Conversion process step is electrified and therefore only scope 2 emissions are considered

# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: Local Storage (1/2)



Category	Parameter	Units	Liquefied Methane <sup>1)</sup>		Ammonia		Methanol	
			Value	Source	Value	Source	Value	Source
Stoichiometry	Electricity input	MWh/ton	1.21	MWh/kg of boiloff, Li & Wen <sup>xxxix)</sup>	0.03	Llyod' s Register <sup>xL)</sup>	0	EU LCA <sup>xii)</sup>
	Losses	%	0% <sup>2)</sup>	EU LCA <sup>xii)</sup>	0.02%	EU LCA <sup>xii)</sup>	0%	EU LCA <sup>xii)</sup>
Asset specifics	CAPEX	EUR/ton	0.05	EUR/MWh/day, Fluxys <sup>xLi)</sup>	909	HyDelta <sup>xxxiii)</sup>	473	HyDelta <sup>xxxiii)</sup>
	OPEX	% of total CAPEX			2.0% <sup>3)</sup>	HyDelta <sup>xxxiii)</sup>	0.7% <sup>3)</sup>	HyDelta <sup>xxxiii)</sup>
	Lifetime	years	40	Fluxys <sup>xLii)</sup>	30	Assumed	30	HyDelta <sup>xxxiii)</sup>
	Utilization	% of 8,760 FLH	98%	Assumed	98%	Assumed	98%	Assumed
	Capacity	kt	265	Fluxys <sup>xLiii)</sup>	55	HyDelta <sup>xxxiii)</sup>	32	HyDelta <sup>xxxiii)</sup>
	Storage Length	days	Duration of sea transport one-way		Duration of sea transport one-way		Duration of sea transport one-way	
Scope 1 Emissions	CO <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable					
	CH <sub>4</sub>	kg of CO <sub>2</sub> e/MWh	0	EU LCA <sup>xii)</sup>				
	N <sub>2</sub> O	kg of CO <sub>2</sub> e/MWh			not applicable		not applicable	
	NO <sub>x</sub>	kg of CO <sub>2</sub> e/MWh						
	H <sub>2</sub>	kg of CO <sub>2</sub> e/MWh						

1) Input also valid for biomethane and fossil natural gas; 2) Boiloff losses (-0.07 %/day) are assumed to be reliquefied; 3) Figures only comprises fixed OPEX excl. feedstock costs

# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: Local Storage (2/2)



Category	Parameter	Units	LOHC		Liquid H <sub>2</sub>	
			Value	Source	Value	Source
Stoichiometry	Electricity input	MWh/ton	0	EU LCA <sup>XII)</sup>	0.15	HyDelta <sup>XXXIII)</sup> , IEA <sup>XLIV)</sup>
	Losses	%/day	0%	EU LCA <sup>XII)</sup>	0% <sup>1)</sup>	IRENA <sup>XXXIV)</sup>
Plant specifics	CAPEX	EUR/ton	322	Ortiz Cebolla et al. <sup>XLV)</sup>	13,650	IRENA <sup>XXXIV)</sup>
	OPEX	% of total CAPEX	1.0% <sup>2)</sup>	Ortiz Cebolla et al. <sup>XLV)</sup>	2.0% <sup>2)</sup>	HyDelta <sup>XXXIII)</sup>
	Lifetime	years	30	HyDelta <sup>XXXIII)</sup>	30	HyDelta <sup>XXXIII)</sup>
	Utilization	% of 8,760 FLH	98%	HyDelta <sup>XXXIII)</sup>	98%	Assumed
	Capacity	kt	30	Ortiz Cebolla et al. <sup>XLV)</sup>	7	HyDelta <sup>XXXIII)</sup>
	Storage Length	days	Duration of sea transport one-way		Duration of sea transport one-way	
Scope 1 Emissions	CO <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		not applicable	
	CH <sub>4</sub>	kg of CO <sub>2</sub> e/MWh				
	N <sub>2</sub> O	kg of CO <sub>2</sub> e/MWh				
	NO <sub>x</sub>	kg of CO <sub>2</sub> e/MWh				
	H <sub>2</sub>	kg of CO <sub>2</sub> e/MWh				

1) Boiloff losses (-0.1%/day) is assumed to be reliquefied, requiring 0.15 kWh per kg of boiloff gas; 2) Value only comprises fixed OPEX, excl. feedstock costs

# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: Maritime transport (1/2)



Category	Parameter	Units	Liquefied Methane			Ammonia			Methanol		
			Value	Source	Comfort	Value	Source	Comfort	Value	Source	Comfort
Stoichiometry	Fuel Consumption	MJ/ton/km	0 <sup>1)</sup>	Agora <sup>XXIII</sup>	High	0.05	IEA <sup>XLIV</sup>	High	0.03 <sup>2)</sup>	Assumed	High
	Losses	%	<0.5%	Assumed	Medium	0.02%	IEA <sup>XLIV</sup>	High	0%	HyDelta <sup>XLVI</sup>	High
	Boiloff Losses	%/day	0.2%	Agora <sup>XXIII</sup>	High	0.02%	IEA <sup>XLIV</sup>	High	0%	HyDelta <sup>XLVI</sup>	High
Asset specifics	CAPEX	EUR/ton	2,834	Agora <sup>XXIII</sup>	High	1,351	IEA <sup>XLIV</sup>	High	515	HyDelta <sup>XXXIII</sup>	High
	OPEX	% of total CAPEX	4% <sup>3)</sup>	Agora <sup>XXIII</sup>	High	4% <sup>3)</sup>	Agora <sup>XXIII</sup>	High	5% <sup>3)</sup>	HyDelta <sup>XXXIII</sup>	High
	Fuel type	-	LNG <sup>4)</sup>	Agora <sup>XXIII</sup>	High	e-NH3	IEA <sup>XLIV</sup>	High	e-MeOH	Assumed	High
	Storage tank cap.	kt of vector	76	Agora <sup>XXIII</sup>	High	52	IEA <sup>XLIV</sup>	High	95	HyDelta <sup>XXXIII</sup>	High
	Lifetime	years	30	Assumed	High	30	HyDelta <sup>XLVI</sup>	High	30	HyDelta <sup>XLVI</sup>	High
	Utilization	% of usage/year	91%	Agora <sup>XXIII</sup>	High	91%	Agora <sup>XXIII</sup>	High	91%	Agora <sup>XXIII</sup>	High
	Speed	km/h	30	Agora <sup>XXIII</sup>	High	32	IEA <sup>XLIV</sup>	High	33	HyDelta <sup>XXXIII</sup>	High
	Suez Canal fee <sup>5)</sup>	EUR m	0.9	Assumed	High	0.7	IRENA <sup>XLVII</sup>	High	1.1	Assumed	High
	Port fees <sup>6)</sup>	EUR k	<215	Ports <sup>XLVIII)(XLIX)(L)(LI)(LII)</sup>	Medium	<200	Ports <sup>XLVIII)(XLIX)(L)(LI)(LII)</sup>	Medium	<225	Ports <sup>XLVIII)(XLIX)(L)(LI)(LII)</sup>	Medium
Scope 1 Emissions	CO <sub>2</sub> , NO <sub>x</sub> , N <sub>2</sub> O	kg of CO <sub>2</sub> e/MWh	Corresponding to combustion of LNG/unloading losses			Corresponding to combustion of NH <sub>3</sub>			Corresponding to MeOH combustion		
	CH <sub>4</sub>	kg of CO <sub>2</sub> e/MWh				not applicable			not applicable		
	H <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable								

1) LNG carrier runs on boiloff losses; 2) Methanol vessels assumed to have identical fuel consumption in MJ/ton as ammonia vessels; 3) Value only comprises fixed OPEX, excl. feedstock costs; 4) CO<sub>2</sub> emissions only accounted for natural gas, as emissions from e-methane or biomethane are net zero; 5) Tariff for roundtrip through Suez canal on MENA route scales by weight of cargo; 6) Port fees of import (Rotterdam) and export port (US: Corpus Christi, MENA: Abu Dhabi, ESP: Huelva, NOR: Greenland)  
 Source: Oxford Institute for Energy Studies, HyDelta, EU LCA, DNV, ZeroCarbon Shipping  
 Comfort level of the assumption: ● High ● Medium ● Low  
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# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: Maritime transport (2/2)



Category	Parameter	Units	LOHC		Liquid H <sub>2</sub>	
			Value	Source	Value	Source
Stoichiometry	Fuel Consumption	MJ/ton/km	0.03 <sup>1)</sup>	Assumed	0 <sup>2)</sup>	IEA <sup>XLIV)</sup>
	Losses	%	0%	HyDelta <sup>XLVI)</sup>	1%	IEA <sup>XLIV)</sup>
	Boiloff Losses	%/day	0%	HyDelta <sup>XLVI)</sup>	0.6%	IEA <sup>XLIV)</sup>
Asset specifics	CAPEX	EUR/ton	471	HyDelta <sup>XXXIII)</sup>	40,196	IEA <sup>XLIV)</sup>
	OPEX	% of total CAPEX	6% <sup>3)</sup>	HyDelta <sup>XXXIII)</sup>	4% <sup>3)</sup>	Agora <sup>XXIII)</sup>
	Fuel type	-	e-MeOH	Assumed	Liquid H <sub>2</sub>	IEA <sup>XLIV)</sup>
	Storage tank cap.	kt of vector	104	HyDelta <sup>XXXIII)</sup>	10	IEA <sup>XLIV)</sup>
	Lifetime	years	30	HyDelta <sup>XLVI)</sup>	30	HyDelta <sup>XLVI)</sup>
	Utilization	% of usage/year	91%	Agora <sup>XXIII)</sup>	91%	Agora <sup>XXIII)</sup>
	Speed	km/h	33	HyDelta <sup>XXXIII)</sup>	30	IEA <sup>XLIV)</sup>
	Suez Canal fee <sup>4)</sup>	EUR m	1.2	Assumed	0.1	Assumed
Port fees <sup>5)</sup>	EUR k	<230	Ports <sup>XLVIII)(XLIX)(L)(LI)(LII)</sup>	<190	Ports <sup>XLVIII)(XLIX)(L)(LI)(LII)</sup>	
Scope 1 Emissions	CO <sub>2</sub> , NO <sub>x</sub> , N <sub>2</sub> O	kg of CO <sub>2</sub> e/MWh	Corresponding to MeOH combustion <sup>1)</sup>		Corresponding to combustion of LH <sub>2</sub>	
	CH <sub>4</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		not applicable	
	H <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		Corresponding to losses of loading	

1) LOHC vessels assumed to use methanol as fuel and have identical fuel consumption in MJ/ton as ammonia vessels; 2) Liquid H<sub>2</sub> carrier runs entirely on boiloff losses; 3) Value only comprises fixed OPEX, excl. feedstock costs; 4) Tariff for a roundtrip through the Suez canal on the MENA route scales by weight of cargo; 5) Port fees of import (Rotterdam) and export port (US: Corpus Christi, MENA: Abu Dhabi, ESP: Huelva, NOR: Greenland)

# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: Pipeline Transportation



Category	Parameter	Units	Compressed methane		Compressed hydrogen	
			Value	Source	Value	Source
Stoichiometry	Electricity input	kWh/ton/km	0.08	EU LCA <sup>xii)</sup>	0.6	Agora <sup>xxiii)</sup>
	Losses	%/1,000 km	0.02%	EU LCA <sup>xii)</sup>	0.40% <sup>1)</sup>	EU LCA <sup>xii)</sup>
Plant specifics	Existing tariff [NOR]	EUR/MWh	10 <sup>2)</sup>	Bottom-up calculation	not applicable	
	Existing tariff [ESP]	EUR/MWh	10 <sup>3)</sup>	Bottom-up calculation	not applicable	
	New tariff	EUR/MWh/1000 km	3.9 <sup>4)</sup>	Assumed	6.0	IEA <sup>Liii)</sup>
	Lifetime	years	55	Assumed	55	Assumed
	Utilization	%	70% <sup>5)</sup>	Calculated	90% <sup>5)</sup>	Calculated
	Pipeline length [NOR]	km	~2,300	Assumed	~ 2,300	Assumed
	Pipeline length [ESP]	km	~2,300	Assumed	~ 2,300	Assumed
	Max. capacity	GW	18.8	Assumed	16.9	IEA <sup>Liii)</sup>
Scope 1 Emissions	CO <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		not applicable	
	CH <sub>4</sub>	kg of CO <sub>2</sub> e/MWh	Corresponding to losses in pipeline		not applicable	
	N <sub>2</sub> O	kg of CO <sub>2</sub> e/MWh	not applicable		not applicable	
	NO <sub>x</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		not applicable	
	H <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		Corresponding to losses in pipeline	

1) Considering total loss of 1% and then dividing by 2.5 to get the loss in %/1,000 km; 2) Pipeline length from NOR and ESP is similar; 3) Tariff assumes transmission from Spain via France and Belgium; 4) NG pipeline cost are assumed by scaling hydrogen pipeline LCOH by 65% to account for fact that CAPEX of NG pipeline is 30-40% cheaper and can carry 10% more volume; 5) Utilization is scaled for the total expected demand by 2040

# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: Gasification



Category	Parameter	Units	Liquified Methane to Gas		Liquified Hydrogen to Gas	
			Value	Source	Value	Source
Stoichiometry	Electricity	MWh/ton	0.06	EU LCA <sup>XII)</sup>	0.2	IRENA <sup>XXXIV)</sup>
	Electricity price	EUR/MWh	92	E-bridge <sup>XV)</sup>	92	E-bridge <sup>XV)</sup>
	Losses	%	0.01%	EU LCA <sup>XII)</sup>	0.01%	Assumed
Asset specifics	CAPEX	EUR/ton	200	Frontier <sup>LIV)</sup>	441	IRENA <sup>XXXIV)</sup>
	OPEX	% of total CAPEX.	2.5%	Assumed	4% <sup>1)</sup>	Brändle et al. <sup>LV)</sup>
	Lifetime	years	30	Assumed	30	Assumed
	Utilization	% of 8,760 FLH	95%	Assumed	95%	Assumed
	Capacity	kt/year	174	TWh, Fluxys <sup>XLIII)</sup>	912	IRENA <sup>XXXIV)</sup>
Scope 1 Emissions	CO <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		not applicable	
	CH <sub>4</sub>	kg of CO <sub>2</sub> e/MWh	Corresponding to losses in pipeline			
	N <sub>2</sub> O	kg of CO <sub>2</sub> e/MWh	not applicable			
	NO <sub>x</sub>	kg of CO <sub>2</sub> e/MWh	not applicable			
	H <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		Corresponding to losses in pipeline	

1) Value only comprises fixed OPEX, excl. feedstock costs

# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: Reconversion



Category	Parameter	Units	Methane to H2 (SMR)		Ammonia to Hydrogen		Methanol to Hydrogen		LOHC (DBT to H <sub>2</sub> )	
			Value	Source	Value	Source	Value	Source	Value	Source
Stoichiometry	Energy vector	ton/ton	1.32	IEA <sup>XLIV</sup>	7.2	HyDelta <sup>XLVI</sup>	7.1	EU LCA <sup>XII</sup>	22.4 <sup>1)</sup>	Assumed
	Electricity	MWh/ton	0 <sup>2)</sup>	EU LCA <sup>XII</sup>	0.99 <sup>3)</sup>	HyDelta <sup>XLVI</sup>	1.3 <sup>2,3)</sup>	EU LCA <sup>XII</sup>	1.9 <sup>3)</sup>	EU LCA <sup>XII</sup>
	Electricity price	EUR/MWh	95	E-bridge <sup>XV</sup>	95	E-bridge <sup>XV</sup>	95	E-bridge <sup>XV</sup>	95	E-bridge <sup>XV</sup>
Asset specifics	CAPEX	EUR/ton	655	EUR/kW, IEA <sup>XLIV</sup>	1,041	HyDelta <sup>XLVI</sup>	455	Agora <sup>XXIII</sup>	769	IRENA <sup>XXXIV</sup>
	OPEX	% of total CAPEX.	5% <sup>4)</sup>	IEA <sup>XLIV</sup>	3% <sup>4)</sup>	IEA <sup>XLIV</sup>	3% <sup>4)</sup>	HyDelta <sup>XXXIII</sup>	2.5% <sup>4)</sup>	HySTOC <sup>XXII</sup>
	Lifetime	years	25	Assumed	25	IEA <sup>XXVII</sup>	25	Assumed	25	Assumed
	Utilization	% of 8,760 FLH	90%	Assumed	90%	Assumed	90%	HyDelta <sup>XXXIII</sup>	90%	Assumed
	Capacity	kt/year	75	HyDelta <sup>XLVI</sup>	270	HyDelta <sup>XLVI</sup>	183	Agora <sup>XXII</sup>	225	IRENA <sup>XXXIV</sup>
Scope 1 Emissions	CO <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	270 <sup>5)</sup>	EU LCA <sup>XII</sup>	not applicable		0 <sup>6)</sup>	EU LCA <sup>XII</sup>	not applicable	
	CH <sub>4</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		not applicable		not applicable		not applicable	
	N <sub>2</sub> O	kg of CO <sub>2</sub> e/MWh	not applicable		<0.01	EU LCA <sup>XII</sup>	not applicable		not applicable	
	NO <sub>x</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		0.5	EU LCA <sup>XII</sup>	not applicable		1.1	EU LCA <sup>XII</sup>
	H <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		0	EU LCA <sup>XII</sup>	0.04	EU LCA <sup>XII</sup>	<0.01	EU LCA <sup>XII</sup>

1) In addition to the required input of DBT (16.3 ton/ton of H<sub>2</sub>), DBT is combusted to provide heat for the reconversion; 2) Methane is combusted for the process heat and therefore no additional energy input is required; 3) Value includes compression of H<sub>2</sub> to 80 bar; 4) Value only comprises fixed OPEX, excl. feedstock costs; 5) Emissions are net zero for e-methane and biomethane; 6) Emissions are net zero and therefore not considered  
 Source: Oxford Institute for Energy Studies, HyDelta, EU LCA  
 Comfort level of the assumption: ● High ● Medium ● Low  
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# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: Transmission



Category	Parameter	Units	e-Methane/Biomethane		Hydrogen		
			Value	Source	Value	Source	
Stoichiometry	Electricity input	kWh/ton/km	0.08	EU LCA <sup>xii)</sup>	0.6	Agora <sup>xxiii)</sup>	
	Losses	%/1,000 km	0.02%	EU LCA <sup>xii)</sup>	0.04% <sup>1)</sup>	EU LCA <sup>xii)</sup>	
Plant specifics	Tariff	EUR/MWh	1.6 <sup>2)</sup>	Bottom-up calculation	1.7	Bottom-up calculation	As cluster 6 and power plants will require a dedicated pipeline they will pay an additional cost to this tariff: <ul style="list-style-type: none"> <li>• Process heat cluster 6: EUR/MWh 16</li> <li>• Electricity production: EUR/MWh 1.4</li> </ul>
	Lifetime	years	55	Assumed	55	Assumed	
	Utilization	% of 8760 FLH	90%	Assumed	90%	Assumed	
	Capacity input	TWh	359 <sup>4)</sup>	Assumed, II3050 <sup>Lvi)</sup>	137	II3050 <sup>Lvi)</sup>	
	Average distance per end-user	km	250	Assumed	250	Assumed	
Scope 1 Emissions	CO <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		not applicable		
	CH <sub>4</sub>	kg of CO <sub>2</sub> e/MWh	Corresponding to losses in pipeline		not applicable		
	N <sub>2</sub> O	kg of CO <sub>2</sub> e/MWh	not applicable		not applicable		
	NO <sub>x</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		not applicable		
	H <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable		Corresponding to losses in pipeline		

1) Considering total loss of 1% and then dividing by 2.5 to get the loss in %/1,000 km; 2) Tariff is the mean of the past five years of annual revenues of Gasunie Transport Services divided by the annual gas supply in the respective year and scaled by a factor of 2.5 to account for reduction in demand; 3) Combination of HTL and RTL pipelines; 4) Includes demand from e-methane and natural gas and demand for export  
 Source: HyDelta, EU LCA, Fluxys

# Backup on the assumptions for transmission pipeline tariffs in 2040

## Transmission tariff calculation – 2024, 2030 and 2040

Parameters	Gas network - 2024	Gas network - 2040	H2-backbone - 2030	H2-backbone - 2040
Capex new [EUR m/km]	Not applicable	Not applicable	3.7	3.7
Capex refurbished [EUR m/km]	Not applicable	Not applicable	0.99	0.99
Refurbished pipeline [%]			70%	70%
Pipeline length [km]	11,256	11,256	1100	1600
Total CAPEX [EUR m]	4584	3670 <sup>1)</sup>	1,997	3,865
Lifetime [y]	55	55	55	55
WACC [%]	4%	4%	4%	4%
Opex [% of Capex]	10%	10%	2.1%	1.5%
TOTEX [EUR m/y]	796	581	160	286
Power [GW]	Not applicable	Not applicable	Not applicable	Not applicable
Volume [TWh]	700	359 <sup>2)</sup>	78	136
<b>Tariff [EUR/MWh]</b>	<b>1.1</b>	<b>1.6</b>	<b>2.0</b>	<b>1.7</b>

### Key assumptions

- CAPEX for hydrogen pipelines is based on HyWay27 and adjusted with inflation percentage of 5.3% year on year between 2021-2024<sup>3)</sup>
- Assuming 30% of the backbone will be new pipelines and 70% will be refurbished pipelines in 2030
- The hydrogen backbone is assumed to be 1100 km in 2030 and 500 km is added to backbone in 2040 to account for additional volume needed
- OPEX for hydrogen backbone is assumed to be 1% of the new value of the backbone

1) Estimated by adding the expected investments to the current book value and subtracting the expected depreciation costs; 2) Includes methane demand for export; 3) HyWay27 estimated the capex per km for the hydrogen backbone in a report published in 2021, we account for the value increase since

# Backup on the assumptions for transmission pipeline tariffs in 2040

## Additional pipeline CAPEX for electricity production & process heat cluster 6 - 2040

Parameters	Electricity production		Process heat for cluster 6	
	Hydrogen	Methane	Hydrogen	Methane
Capex new [EUR m/km]	1.9	Assumed to be directly connected to the main transmission grid	2.5	Assumed to be directly connected to the main transmission grid
Capex refurbished [EUR m/km]	0.5		1.25	
New pipeline [%]	50%		50%	
Pipeline length [km]	150		400	
Total CAPEX [EUR m]	177		750	
Lifetime [years]	55		55	
WACC [%]	8%		8%	
OPEX [% of CAPEX]	1.6%		1.3%	
TOTEX [EUR m/year]	13		54	
Volume [TWh]	14		5	
<b>Tariff for H<sub>2</sub> [EUR/MWh]</b>	<b>1.4</b>		<b>16</b>	

Based on pipeline with 20-30 cm diameter multiplied by scaling factor of 2.5

### Key assumptions

- Power plants and industrial facilities in cluster 6 will require dedicated pipelines to connect to the hydrogen backbone
- The additional CAPEX is accounted via an added tariff
- WACC of 8% is assumed as cost of capital will be higher for private players compared to GTS
- In electricity production, pipeline diameter is assumed to be 50% of the diameter of the H<sub>2</sub> backbone pipeline resulting in 50% of the H<sub>2</sub> backbone CAPEX
- In cluster 6 industry, a factor of 2-3 to the original Capex numbers is applied to account for additional complexities and safety adherences in the placing of the pipelines
- Length of additional pipeline required is based on the HyRegions report
  - In electricity production 9 power plants are not directly connected to the backbone, also based on the HyRegions report

# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: Seasonal storage



Category	Parameter	Units	e-Methane/Biomethane			Hydrogen		
			Value	Source	Comfort level	Value	Source	Comfort level
Stoichiometry	Electricity input	MWh/MWh	0.02	Assumed	Low	0.03	HyDelta <sup>XXXIII</sup> )	Low
	Losses	%/day	0.02%	Assumed	Low	0.04%	IEA <sup>LVII</sup> )	Low
Plant specifics	Depleted gas field tariff	EUR/MWh	10	Bottom-up calculation	High	36	Bottom-up calculation	High
	Salt cavern tariff	EUR/MWh	15	Bottom-up calculation	High	51	Bottom-up calculation	High
	Share of gas sent to storage	% of total gas						
Scope 1 Emissions	CH <sub>4</sub>	kg of CO <sub>2e</sub> /MWh	Corresponding to losses			not applicable		
	H <sub>2</sub>	kg of CO <sub>2e</sub> /MWh	not applicable			Corresponding to losses		

Different share of gas sent to storage assumed per use case:

- Iron & steel 5-15%
- Process heat cluster 1-5 5-15%
- Process heat cluster 6 5-15%
- Electricity production 25-35%
- Decentral heating 35-45%

1) Number only covers fixed OPEX, excl. feedstock costs

# Backup on the assumptions for seasonal storage tariffs in 2040

Seasonal storage tariff calculation for hydrogen and e-methane<sup>1)</sup>

	Depleted gas field		Salt cavern	
	H <sub>2</sub>	E-CH <sub>4</sub>	H <sub>2</sub>	E-CH <sub>4</sub>
Working gas volume [bcm]	0.78	0.78	0.08	0.08
Cushion gas volume [bcm]	2.00	2.00	0.06	0.06
Lease rate [EUR m/year]	10	10	<i>not applicable</i>	
Storage CAPEX [EUR m]	<i>no additional investment needed</i>		60	60
Cushion gas CAPEX [EUR m]	540	693	17	22
Compression CAPEX [EUR m]	11.9	4.0	10.0	3.3
Wells/piping CAPEX [EUR m]	4.4	4.4	3.2	3.2
Gas cleaning CAPEX [EUR m]	30.7	<i>Assuming no gas cleaning required</i>		
OPEX [EUR m / year]	16.3	12.5	1.6	2.0
Lifetime [years]	30	30	30	30
WACC [%]	8%	8%	8%	8%
<b>LCOS [EUR/MWh]</b>	<b>35</b>	<b>10</b>	<b>51</b>	<b>15</b>

## Key assumptions

- Assuming H<sub>2</sub> price of 3 EUR/kg and CH<sub>4</sub> price of 30 EUR/MWh
- A mix of green and blue hydrogen is used as cushion gas for hydrogen storage and natural gas is used as cushion gas for e-methane storage
- CAPEX for methane compressors assumed to be one third of CAPEX for hydrogen compressors
- No cleaning assumed for e-methane in depleted gas fields or for e-methane or hydrogen in salt caverns
- Salt caverns assumed to have 2 cycles/year

1) Taking half the H<sub>2</sub> and CH<sub>4</sub> price would lead to tariffs of 22.3 and 6.1 EUR/MWh for H<sub>2</sub> and e-CH<sub>4</sub> storage resp. in depleted gas fields & 41.6 and 11.4 EUR/MWh for H<sub>2</sub> and e-CH<sub>4</sub> storage resp. in salt caverns

# Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Distribution – Iron & steel



As Tata Steel is expected to be directly connected to backbone there would be no additional last mile cost

# Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: End-use conversion – Iron & steel



Category	Parameter	Units	e-Methane/Biomethane		Hydrogen	
			Value	Source	Value	Source
Stoichiometry	Methane	MWh/ton steel	2.4	TSN <sup>LVIII</sup> , Agora <sup>XXIII</sup>	●	not applicable
	Hydrogen	MWh/ton steel	not applicable			2.2 TSN <sup>LVIII</sup> , Agora <sup>XXIII</sup> ●
	Electricity	MWh/ton steel	0.8	TSN <sup>LVIII</sup> , Agora <sup>XXIII</sup>	●	0.8 TSN <sup>LVIII</sup> , Agora <sup>XXIII</sup> ●
	Coal	ton/ton steel	0.03	TSN <sup>LVIII</sup> , Agora <sup>XXIII</sup>	●	0.03 TSN <sup>LVIII</sup> , Agora <sup>XXIII</sup> ●
Plant specifics	CAPEX	EUR/ton steel	750 <sup>1)</sup>	DIW <sup>LIX</sup>	●	750 <sup>1)</sup> DIW <sup>LIX</sup> ●
	Demand	TWh/year	14	I13050 <sup>LV1</sup>	●	14 I13050 <sup>LV1</sup> ●
	Other plant specific financials not considered <sup>2)</sup>					
Scope 1 Emissions	CO <sub>2</sub>	kg of CO <sub>2</sub> e/ton steel	80 <sup>2)</sup>	Climate accountability <sup>LX</sup>	●	80 Climate accountability <sup>LX</sup> ●
	CH <sub>4</sub>	kg of CO <sub>2</sub> e/ton steel	not applicable			not applicable
	N <sub>2</sub> O	kg of CO <sub>2</sub> e/ton steel				
	NO <sub>x</sub>	kg of CO <sub>2</sub> e/ton steel				
	H <sub>2</sub>	kg of CO <sub>2</sub> e/ton steel	not applicable			not applicable

1) The financial analysis is focused on cost of energy required per ton of steel and as the costs for an e-methane and hydrogen DRI system are the same, plant specific financials are not considered. Only for the total investment cost analysis for the Netherlands, CAPEX for a DRI system is considered; 2) Emissions for natural gas assumed to be 600 kg of CO<sub>2</sub>/ton steel  
 Source: TSN IJmuiden, Agora, DIW, I13050  
 Comfort level of the assumption: ● High ● Medium ● Low

# For low-emission iron & steel production, a new direct reduced iron (DRI) system is required, either for e-methane or for hydrogen at the same costs

Options considered for end-use conversion of e-methane and hydrogen – Iron & steel

		Technological feasibility	Considerations	CAPEX [EUR/ton]	OPEX [EUR/ton/yr]
New asset	E-methane	✓	Same costs assumed for a new DRI system on e-methane as for a new DRI system on hydrogen	750 <sup>1)</sup>	Not considered <sup>1)</sup>
	Hydrogen	✓		750 <sup>1)</sup>	Not considered <sup>1)</sup>
Depreciated CH <sub>4</sub> asset within lifetime (with adaptations if required)	E-methane	✗	Currently used technology not compatible with e-methane or hydrogen	n.a.	n.a.
	Hydrogen	✗		n.a.	n.a.
Lifetime extension of CH <sub>4</sub> asset (with adaptations if required)	E-methane	✗	Currently used technology not compatible with e-methane or hydrogen	n.a.	n.a.
	Hydrogen	✗		n.a.	n.a.

✓ Technologically feasible ✗ Not technologically feasible [dotted border] Selected option for comparison – Based on age of current assets & technological feasibility

1) The financial analysis is focused on cost of energy required per ton of steel and as the costs for an e-methane and hydrogen DRI system are the same, plant specific financials are not considered. Only for the total investment cost analysis for the Netherlands, CAPEX for a DRI system is considered

# Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Distribution – Process heat



As industry in cluster 1-6 are expected to be directly connected to national transmission network there would be no additional last mile cost

# Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: End-use conversion – Process heat



Category	Parameter	Units	e-Methane/Biomethane			Hydrogen		
			Value	Source	Comfort level	Value	Source	Comfort level
<b>Stoichiometry</b>	Heat efficiency	%	90%	TNO <sup>LXI</sup> , IRENA <sup>XLVII</sup> )	●	90%	Assumed	●
<b>Plant specifics</b>	CAPEX	EUR/kW	0	Assumed	●	14	CE Delft <sup>LXII</sup> )	●
	OPEX	EUR/kW/year	2.8	Assumed, IRENA <sup>XLVII</sup> )	●	4.0	TNO <sup>LXIII</sup> )	●
	Retrofitted	%	100%	Assumed	●	100%	Assumed	●
	Lifetime	years	30	Assumed	●	30	Assumed	●
	Utilization	%	90% <sup>1)</sup>	Assumed	●	90% <sup>1)</sup>	Assumed	●
	Total demand	TWh/year	31	II3050 <sup>LVI</sup> )	●	31	II3050 <sup>LVI</sup> )	●
<b>Scope 1 Emissions</b>	CO <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable <sup>2)</sup>			not applicable		
	CH <sub>4</sub>	%	0.05%	Assumed	●	not applicable		
	N <sub>2</sub> O	kg of CO <sub>2</sub> e/MWh	0.61	US NETL <sup>IX</sup> )	●	not applicable		
	NO <sub>x</sub>	g NO <sub>x</sub> /MWh <sup>3)</sup>	50	TNO <sup>LXIV</sup> )	●	16.5	TNO <sup>LXIV</sup> )	●
	H <sub>2</sub>	%	not applicable			0.25%	IEA <sup>LXV</sup> )	●

1) Figure assumes full load hours of 8,760 per year; 2) Emissions for natural gas assumed to be 0.22 ton CO<sub>2</sub>/MWh from stoichiometric calculation of combustion; 3) At 3% O<sub>2</sub>

# Most industrial plants in the Netherlands have methane boilers in place which can likely be retrofitted to hydrogen boilers if needed at relatively low costs

Options considered for end-use conversion of e-methane and hydrogen – Process heat

	Technological feasibility	Considerations	CAPEX [EUR/kW]	OPEX [EUR/kW/yr]
New asset	E-methane ✓	Some especially older industrial methane boilers can be replaced by new industrial methane boilers or for new industrial plants a new methane boiler can be bought	70	2.5
	Hydrogen ✓	Some especially older industrial methane boilers can be replaced by new industrial hydrogen boilers or for new industrial plants a new hydrogen boiler can be bought	100	3.6
Depreciated CH <sub>4</sub> asset within lifetime (with adaptations if required)	E-methane ✓	Most current industrial methane boilers can likely be used without extra costs	0	2.8 <sup>1)</sup>
	Hydrogen ✓	Most current industrial methane boilers can likely be retrofitted to hydrogen with relatively low extra costs	14	4.0 <sup>1)</sup>
Lifetime extension of CH <sub>4</sub> asset (with adaptations if required)	Not considered as an option due to relatively low CAPEX costs			

✓ Technologically feasible    ✗ Not technologically feasible    [Dotted Box] Selected option for comparison – Based on age of current assets & technological feasibility

1) Assuming 10% higher OPEX for older assets

# Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: Distribution – Electricity production



As power plants are expected to be directly connected to national transmission network there would be no additional last mile cost

# Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: End-use conversion – Electricity production



Category	Parameter	Units	e-Methane/Biomethane			Hydrogen		
			Value	Source	Comfort level	Value	Source	Comfort level
Stoichiometry	Electricity efficiency	%	60%	TNO <sup>LXVI</sup> )	High	60%	TNO <sup>LXVI</sup> )	High
	Heat efficiency	%	30%	EPA <sup>LXVII</sup> )	High	30%	Assumed	High
Plant specifics	CAPEX	EUR/kW	350 <sup>1)</sup>	TNO <sup>LXVI</sup> )	High	409 <sup>1)</sup>	TNO <sup>LXVI</sup> )	Medium
	OPEX	EUR/kW/year	11	Assumed, TNO <sup>LXVI</sup> )	High	12	Assumed, TNO <sup>LXVI</sup> )	Medium
	Lifetime	years	30	Assumed	High	30	Assumed	High
	Utilization	Full load hours	1,194	II3050 <sup>LXVIII</sup> )	High	1,194	II3050 <sup>LXVIII</sup> )	High
	Total demand	TWh	14	II3050 <sup>LVI</sup> )	High	14	II3050 <sup>LVI</sup> )	High
Scope 1 Emissions	CO <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable <sup>3)</sup>			not applicable		
	CH <sub>4</sub>	%	0.05%	Assumed	High	not applicable		
	N <sub>2</sub> O	kg of CO <sub>2</sub> e/MWh	0.91	US NETL <sup>(X)</sup>	High	not applicable		
	NO <sub>x</sub>	g NO <sub>x</sub> /MWh <sup>2)</sup>	35	TNO <sup>LXIV</sup> )	High	17	TNO <sup>LXIV</sup> )	Medium
	H <sub>2</sub>	%	not applicable			0.2%	IEA <sup>LXV</sup> )	Medium

1) Including costs for increasing lifetime – 350 EUR/kW for both methane and hydrogen; 2) At 15% O<sub>2</sub>; 3) Emissions for natural gas assumed to be 0.42 ton CO<sub>2</sub>/MWh, source US NETL

# Power plants in the Netherlands are in general relatively old, but lifetime can likely be extended (possibly in combination with hydrogen retrofitting)

Options considered for end-use conversion of e-methane and hydrogen – Electricity production

				CAPEX [EUR/kW]	OPEX [EUR/kW/yr]
<b>New asset</b>	E-methane	✓	Some especially older methane power plants can be replaced by new methane power plants or buying new methane power plants can increase total capacity	700	10
	Hydrogen	✓	Some especially older methane power plants can be replaced by new hydrogen power plants or buying new hydrogen power plants can increase total capacity	770	11
<b>Depreciated CH<sub>4</sub> asset within lifetime</b> (with adaptations if required)	E-methane	✓	Some current methane power plants can likely be used without extra costs	0	11 <sup>1)</sup>
	Hydrogen	✓	Some current methane power plants can likely be retrofitted to hydrogen without lifetime extension	59	12 <sup>1)</sup>
<b>Lifetime extension of CH<sub>4</sub> asset</b> (with adaptations if required)	E-methane	✓	Most current methane power plants in the Netherlands likely require lifetime extension	350	11 <sup>1)</sup>
	Hydrogen	✓	Most current methane power plants in the Netherlands likely require lifetime extension and potential retrofitting to hydrogen	409	12 <sup>1)</sup>

✓ Technologically feasible    ✗ Not technologically feasible    [Dotted Box] Selected option for comparison – Based on age of current assets & technological feasibility

1) Assuming 10% higher OPEX for older assets

# Overview of the assumptions for all selected renewable energy vectors in 2040

## Assumptions: Distribution – Decentral heating



Category	Parameter	Units	e-Methane/Biomethane		Hydrogen		
			Value	Source	Value	Source	
Stoichiometry	Electricity input	kWh/ton/km	0.08	EU LCA <sup>XII</sup> )	0.6	Agora <sup>XXXIII</sup> )	
	Losses	%/1,000 km	0.02%	EU LCA <sup>XII</sup> )	0.40% <sup>1)</sup>	EU LCA <sup>XII</sup> )	
Pipeline specifics	New	Tariff	EUR/MWh	19 <sup>2)</sup>	Assumed	55	Calculated
		CAPEX	EUR m/km	not applicable		0.3	IRENA <sup>XXXIV</sup> )
	OPEX	% of CAPEX	1%			Assumed	
	Retro-fitted	CAPEX	EUR m/km			0.1	IRENA <sup>XXXIV</sup> )
		OPEX	% of CAPEX			1% <sup>3)</sup>	Assumed
	Retrofitted	%	50%			Assumed	
	Lifetime	years	55			Assumed	
	WACC	%	4%			Dutch Climate Ministry <sup>LXIX</sup> )	
	Pipeline length	km	82,718			Calculated	
	Total demand	TWh/year	47 <sup>4)</sup>			I13050 <sup>LVI</sup> )	23
Av. distance per end user	km	60	Assumed			60	Assumed
Scope 1 Emissions	CO <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	Corresponding to losses in pipeline		Corresponding to losses in pipeline		
	H <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	Corresponding to losses in pipeline		Corresponding to losses in pipeline		

1) Considering total loss of 1% and then dividing by 2.5 to get the loss in %/1,000 km; 2) Dividing the sum of the 2040 depreciation costs, cost of capital and OPEX by the demand; 3) OPEX as percentage of new values of pipelines; 4) Demand including fossil methane  
 Source: EU LCA, HyWay 27, IRENA, I13050

# Overview of the assumptions for all selected renewable energy vectors in 2040

Assumptions: End-use conversion – Decentral heating



Category	Parameter	Units	e-Methane/Biomethane		Hydrogen		
			Value	Source	Value	Source	
<b>Stoichiometry</b>	Heat efficiency	%	92% <sup>1)</sup>	TNO <sup>LXX</sup>	92% <sup>1)</sup>	TNO <sup>LXX</sup>	
<b>Boiler specifics</b>	CV	CAPEX	EUR per boiler	0	Assumed	5,000	Nefit Bosch <sup>LXXI</sup>
		OPEX	EUR/year	100	Feenstra <sup>LXXII</sup>	100	Assumed
		Number of boilers	# m	0.25 <sup>2)</sup>	I13050 <sup>LXVIII</sup>	0.24 <sup>2)</sup>	I13050 <sup>LXVIII</sup>
	Hybrid heat pump	CAPEX	EUR per boiler	0	Assumed	11,000 <sup>3)</sup>	Assumed, Milieu Centraal <sup>LXXIII</sup>
		OPEX	EUR/year	200	Feenstra <sup>LXXIV</sup>	200	Assumed
		Number of boilers	# m	1.7 <sup>2)</sup>	I13050 <sup>LXVIII</sup>	1.4 <sup>2)</sup>	I13050 <sup>LXVIII</sup>
		Lifetime	years	15	Feenstra <sup>LXXV</sup>	15	Assumed
<b>Total demand</b>	TWh/year	23	I13050 <sup>LV</sup>	23	I13050 <sup>LV</sup>		
<b>Scope 1 Emissions</b>	CO <sub>2</sub>	kg of CO <sub>2</sub> e/MWh	not applicable <sup>4)</sup>		not applicable		
	CH <sub>4</sub>	%	0.05%	Assumed	not applicable		
	N <sub>2</sub> O	kg of CO <sub>2</sub> e/MWh	0.60	US NETL <sup>IX</sup>	not applicable		
	NO <sub>x</sub>	g NO <sub>x</sub> /MWh <sup>5)</sup>	50	TNO <sup>LXIV</sup>	10.5	TNO <sup>LXIV</sup>	
	H <sub>2</sub>	%	not applicable		0.25%	Oxford Energy Institute <sup>LXXVI</sup>	

1) Based on HHV; 2) 2050 values for residential boilers scaled based on 2040 demand - Utilities relatively small compared to residential, so not considered here; 3) Hybrid heat pumps include both a CV and pump, price is the sum of both elements; 4) Emissions for natural gas assumed to be 0.22 ton CO<sub>2</sub>/MWh from stoichiometric calculation of combustion; 5) at 3% O<sub>2</sub>

# In the Netherlands, boilers for decentral heating currently almost all run on methane - Retrofitting those to hydrogen is likely not technologically feasible

Options considered for end-use conversion of e-methane and hydrogen - Decentral heating

		Technological feasibility	Considerations	CAPEX		OPEX	
				[EUR/CV]	[EUR/HHP]	[EUR/CV /year]	[EUR/HHP /year]
New asset	E-methane	✓	Some especially older decentral methane boilers can be replaced by new decentral methane boilers - Likely limited use case for new methane boilers for newbuild	2,000	8,000	100	200
	Hydrogen	✓	Some especially older decentral methane boilers can be replaced by new decentral hydrogen boilers - Likely limited use case for new hydrogen boilers for newbuild	5,000	11,000	100	200
Depreciated CH <sub>4</sub> asset within lifetime (with adaptations if required)	E-methane	✓	Most current decentral methane boilers can likely be used without extra costs	0	0	100 <sup>1)</sup>	200 <sup>1)</sup>
	Hydrogen	✗		n.a.	n.a.	n.a.	n.a.
Lifetime extension of CH <sub>4</sub> asset (with adaptations if required)	E-methane	✗	Lifetime extension of decentral methane boilers and/or retrofitting existing decentral methane boilers to hydrogen likely not technologically feasible	n.a.	n.a.	n.a.	n.a.
	Hydrogen	✗		n.a.	n.a.	n.a.	n.a.

✓ Technologically feasible ✗ Not technologically feasible [dotted border] Selected option for comparison - Based on age of current assets & technological feasibility

... CV ("Centrale Verwarming") ● HHP (Hybrid Heat Pump)

1) Assuming the same OPEX also for older assets due to fixed maintenance contracts

# Different sources have been used for the assumptions

## Reference list (1/4)

- I. Energy conversion calculator, NRG Energy
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- III. Fuels - Higher and Lower Calorific Values, The Engineering Toolbox
- IV. Energy Supply Systems for Buildings: Summary table with heating values and CO2 emissions, TU Delft
- V. Wasserstoffträgersysteme, Deutscher Bundestag, 2020
- VI. Sixth Assessment Report, IPCC
- VII. Greenhouse effect of NOx, Lammel & Graßl, 1995
- VIII. A multi-model assessment of the Global Warming Potential of hydrogen, Sand et al., 2023
- IX. Life Cycle Analysis of Natural Gas Extraction and Power Generation, US NETL, 2014
- X. Managing emissions from ammonia-fueled vessels, Zero Carbon Shipping, 2023
- XI. Methanol as marine fuel: Environmental benefits, technology readiness, and economic feasibility, DNV, 2016
- XII. Environmental life cycle assessment (LCA) comparison of hydrogen delivery options within Europe, EU, 2024
- XIII. Annual Energy Outlook 2023, EIA, 2022
- XIV. Internationaler Energiepreisvergleich für die Industrie, Vereinigung der Bayerischen Wirtschaft e. V., 2023
- XV. Electricity cost assessment for large industry in the Netherlands, Belgium, Germany and France, E-bridge, 2024
- XVI. Carbon intensity of electricity generation in selected regions in the Sustainable Development Scenario, 2000-2040, IEA
- XVII. CO<sub>2</sub> intensity of electricity generation, Enerdata
- XVIII. Availability and costs of liquefied bio- and synthetic methane, CE Delft, 2020
- XIX. Visie op koolstof-verwijdering, Natuur & Milieu, 2024
- XX. NETL's Cost of Capturing CO2 from Industrial Sources and Industrial Carbon Capture Retrofit Database, US NETL, 2023

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- XXI. Levelised Cost of Hydrogen Maps, IEA, 2023
- XXII. LOHC production cost estimation study, HySTOC, 2018
- XXIII. Wasserstoff-Importoptionen für Deutschland, Agora, 2023
- XXIV. Canadian natural gas sector breakeven costs among lowest of top 10 major producing countries, Canadian Energy Centre, 2023
- XXV. Global Hydrogen Review 2021, IEA, 2021
- XXVI. Insights into the current cost of biomethane production from real industry data, BIP Europe, 2023
- XXVII. IEA G20 Hydrogen report: Assumptions, IEA, 2020
- XXVIII. Gas for Climate. The optimal role for gas in a net zero emissions energy system, Navigant, 2019
- XXIX. INPEX, Osaka Gas set for world's largest-scale methanation plant, eye LNG production, S&P Global, 2021
- XXX. Geographical analysis of biomethane potential and costs in Europe in 2050, Engie, 2021
- XXXI. LCA of power-to-methane systems with CO<sub>2</sub> supplied by the chemical looping combustion of biomass, Navajas et al., 2022
- XXXII. Methane emissions, IEA bioenergy, 2017
- XXXIII. Technical analysis of H<sub>2</sub> supply chains, HyDelta, 2023
- XXXIV. Global hydrogen trade to meet the 1.5°C climate goal: Part II – Technology review of hydrogen carriers, IRENA, 2022
- XXXV. Import options for green hydrogen and derivatives – An overview of efficiencies and technology readiness levels, Sterner et al., 2024
- XXXVI. The LNG Shipping Forecast: Costs rebounding, outlook uncertain, Oxford Institute for Energy Studies, 2018
- XXXVII. Economic Feasibility of LNG Business: An Integrated Model and Case Study Analysis, Zhang et al., 2024
- XXXVIII. LNG: National and global benefits, Appea
- XXXIX. Design & dynamic optimization of BOG two-stage compression & recondensation process at LNG receiving terminal, Li & Wen, 2016
- XL. Techno-economic assessment of zero-carbon fuels, Lloyd's Register

# Different sources have been used for the assumptions

## Reference list (3/4)

- XLII. Fluxys LNG Tariffs, Fluxys
- XLIII. Fluxys Annual report 2023, Fluxys, 2023
- XLIV. Specifications of Zeebrugge and Dunkirk, Fluxys
- XLV. Global Hydrogen Review 2023, IEA, 2023
- XLVI. Assessment of hydrogen delivery options, Ortiz Cebolla et al., 2022
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- L. Tariff 200, Port Corpus Christi, 2024
- LI. 2024 tariff for LNG tankers, GAC, 2023
- LII. Fees and rates of the Port Authority of Huelva, Puerto de Huelva, 2023
- LIII. Fees and rates of the Port of Grenland, Norway, 2024
- LIV. Global Hydrogen Review 2022, IEA, 2022
- LVI. Komparative Analyse der Importkosten von synthetischem Methan nach Deutschland, Frontier, 2024
- LVII. Estimating global production and supply costs for green hydrogen and hydrogen-based green energy commodities, Moritz et al., 2022
- LVIII. Het energiesysteem van de toekomst: de II3050-scenario's: Integrale energiesysteemverkenning 2030-2050, Netbeheer Nederland, 2023
- LIX. Underground Hydrogen Storage, IEA, 2023
- LX. Feasibility study on climate-neutral pathways for TSN IJmuiden, FNV, TATA Steel Netherlands, Roland Berger, 2021
- LXI. Revisiting Investment Costs for Green Steel: Capital Expenditures, Firm Level Impacts, and Policy Implications, DIW, 2024
- LXII. Coal emissions, Climate Accountability Institute, 2014

# Different sources have been used for the assumptions

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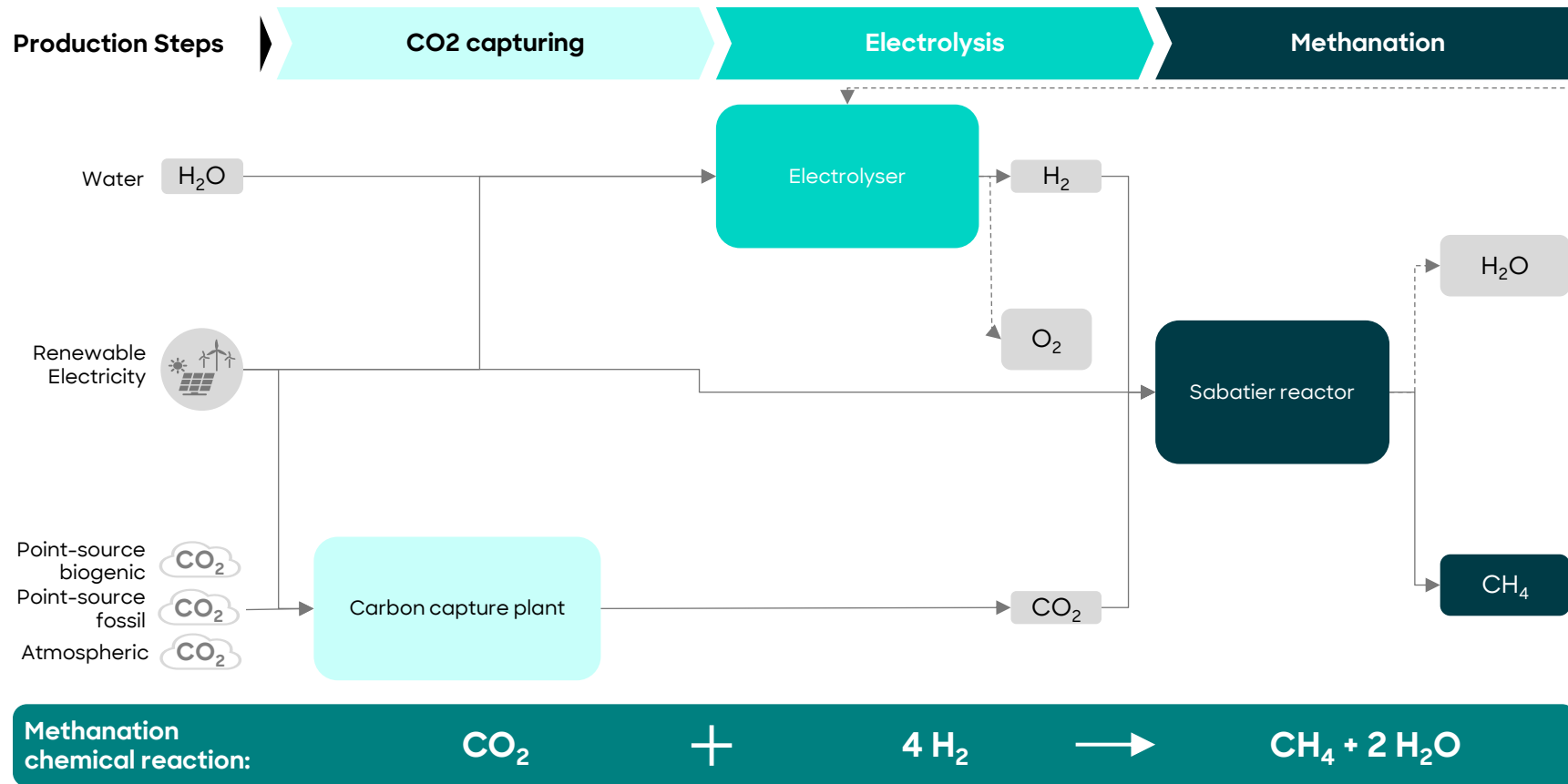
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- LXII. Werk door investeringen in groene waterstof (update en uitbreiding), CE Delft, 2021
- LXIII. Technology factsheet: H<sub>2</sub> industrial boiler, TNO, 2020
- LXIV. Waterstofverbranding en stikstofemissies, TNO, 2023
- LXV. Global Hydrogen Review 2024, IEA, 2024
- LXVI. Naar een CO<sub>2</sub>-vrije elektriciteitsvoorziening in 2040 - een verkenning, TNO, 2023
- LXVII. Methods for Calculating CHP Efficiency, EPA
- LXVIII. Integrale infrastructuurverkenning 2030-2050, Netbeheer Nederland
- LXIX. Hydrogen State of Play, Ministerie van Economische Zaken en Klimaat, 2024
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- LXXI. "Koop een ketel die op waterstof kan", Nefit Bosch, 2021
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- LXXIII. Nieuwe cv-ketel of combiketel kopen, Milieu Centraal
- LXXIV. Onderhoud hybride warmtepomp, Feenstra
- LXXV. Cv-ketel vervangen, Feenstra
- LXXVI. Review of Hydrogen Leakage along the Supply Chain, Oxford Institute for Energy Studies, 2024



## **B. E-methane production technology deepdives**

# Sabatier methanation is the only commercialized synthesis method, employing a two-stage process, although it has a relatively low efficiency of 55-60%

## Technology deepdive: Sabatier methanation



### Description

- Sabatier methanation is a **two-stage process** that produces methane (CH<sub>4</sub>) by reacting hydrogen (H<sub>2</sub>) with carbon dioxide (CO<sub>2</sub>) over a nickel catalyst at 200-500°C and 1-10 bar.
- In the first stage, **hydrogen is generated via water electrolysis**, followed by **reaction with CO<sub>2</sub> in the methanation stage**
- The Audi e-gas plant in Germany, with a **6 MW electric capacity**, is the world's **largest green methanation plant**
- **In China, Sabatier methanation on gas field coal is operated at GW scale**

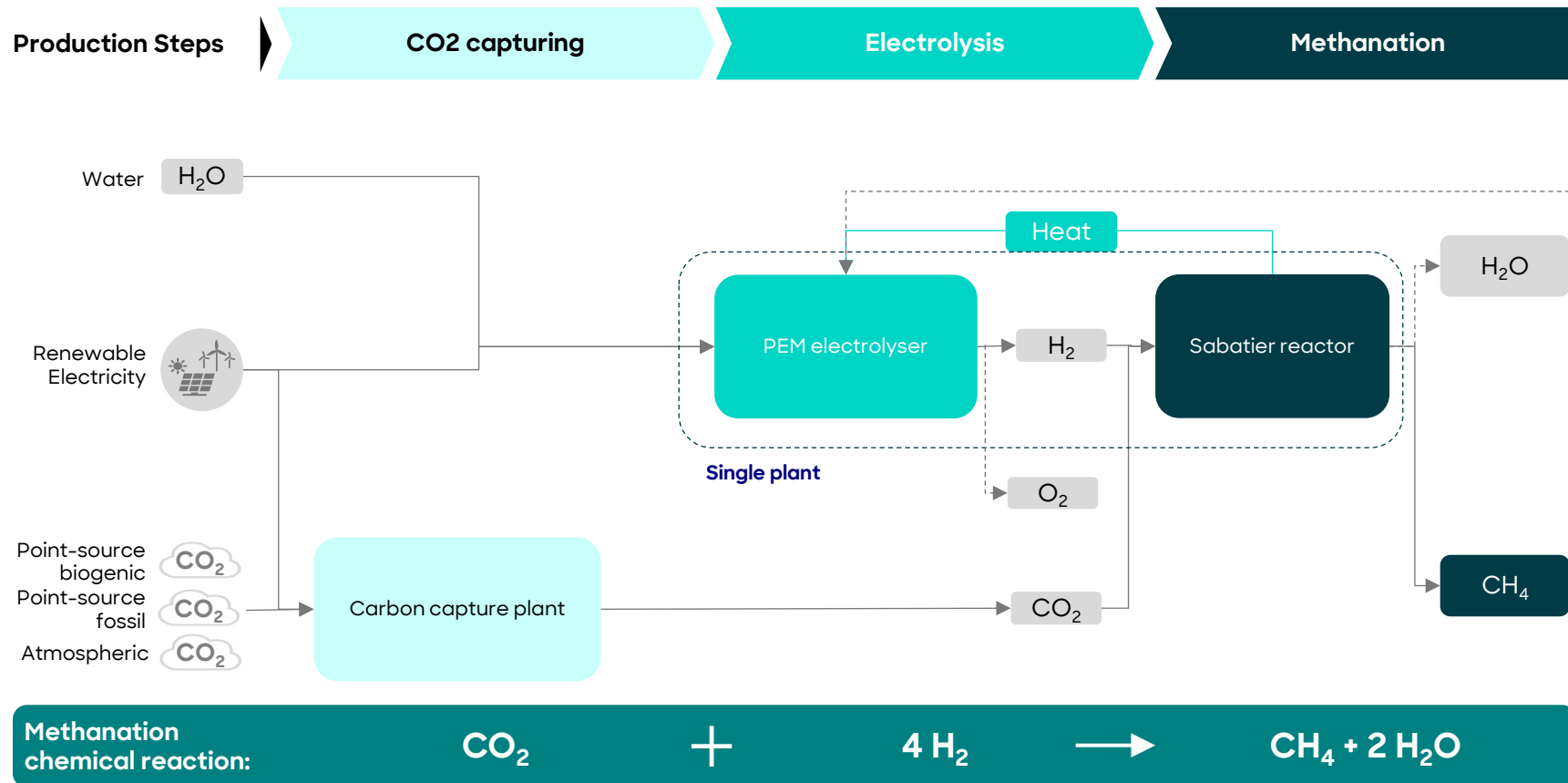
### Key parameter:

Category	Value
Technology maturity	High
Methanation temperature [°C]	200-500
Overall process efficiency <sup>1)</sup> [%]	65%

1) Process efficiency describes the combined efficiency of the electrolysis and methanation step. The efficiency of electrolysis is expected to be 76% by 2040

# Hybrid Sabatier methanation combines electrolysis and methane synthesis within a single plant, utilizing the heat generated during methanation

Technology deepdive: Hybrid conventional Sabatier methanation



## Description

- Hybrid Sabatier methanation **combines electrolysis and methane formation within a single plant**, utilizing the heat generated during methanation to drive the endothermic water electrolysis step
- This technology **eliminates the need for separate hydrogen procurement** and achieves **higher efficiency** than traditional Sabatier methanation through effective waste heat utilization
- A **pilot project has been launched** by Tokyo Gas and JAXA, with **commercialization expected after 2040**

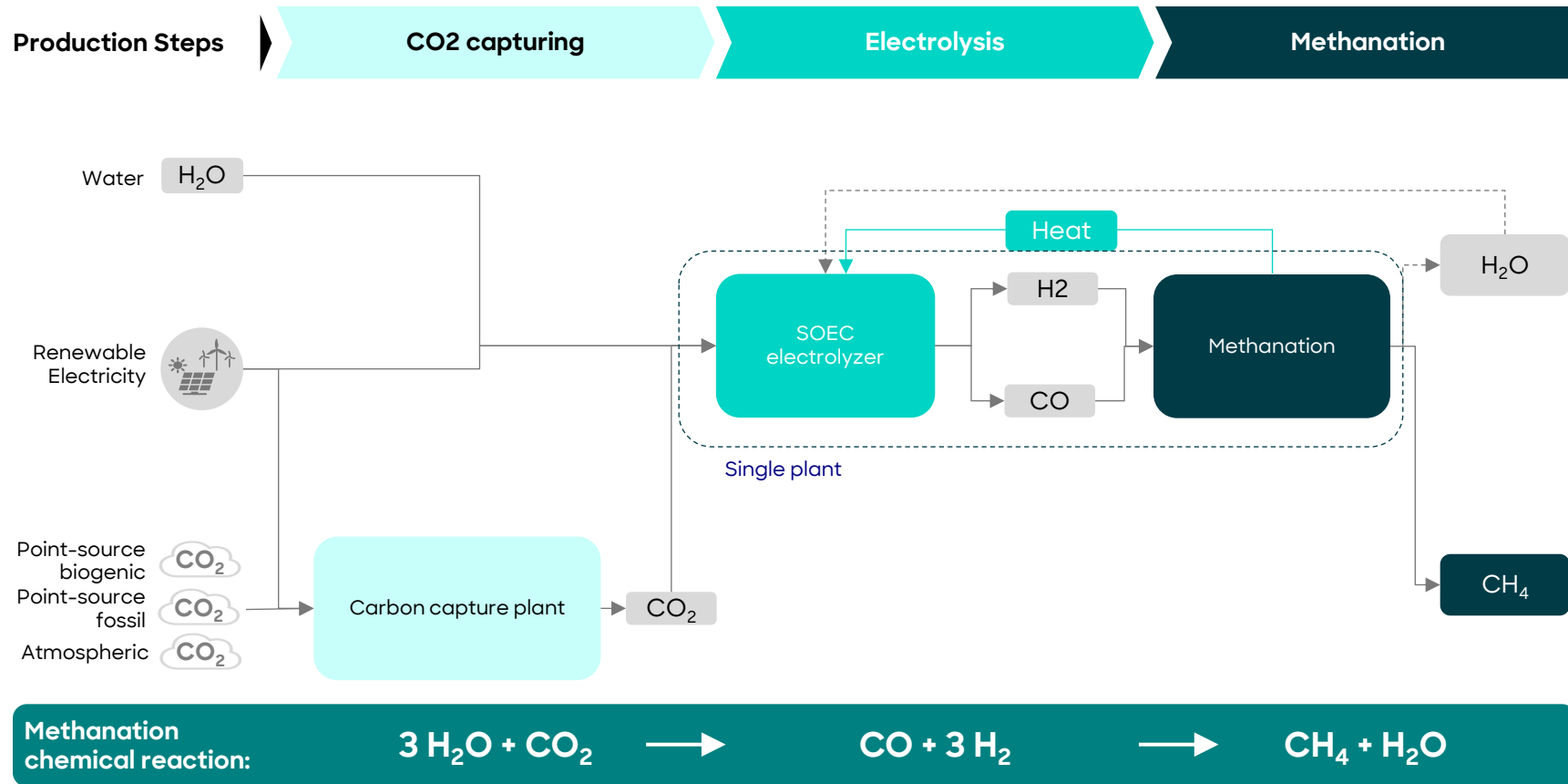
## Key parameter: Category

Category	Value
Technology maturity	Medium
Methanation temperature [°C]	220
Overall process efficiency <sup>1)</sup> [%]	80%

1) Process efficiency describes the combined efficiency of the electrolysis and methanation step

# SOEC methanation integrates high temperature co-electrolysis of H<sub>2</sub>O and CO<sub>2</sub> and methane synthesis within a single plant, achieving high efficiencies

Technology deepdive: Hybrid SOEC methanation



## Description

- SOEC methanation combines the **co-electrolysis of H<sub>2</sub>O and CO<sub>2</sub> with methane synthesis in a single plant**
- This technology **eliminates the need for separate hydrogen procurement** and achieves **higher efficiency than traditional Sabatier methanation** through effective waste heat utilization
- Osaka Gas is currently conducting **pilot testing**, demonstrating efficiencies of 85% to 90%
- **Commercialization** is anticipated in the **2040s**

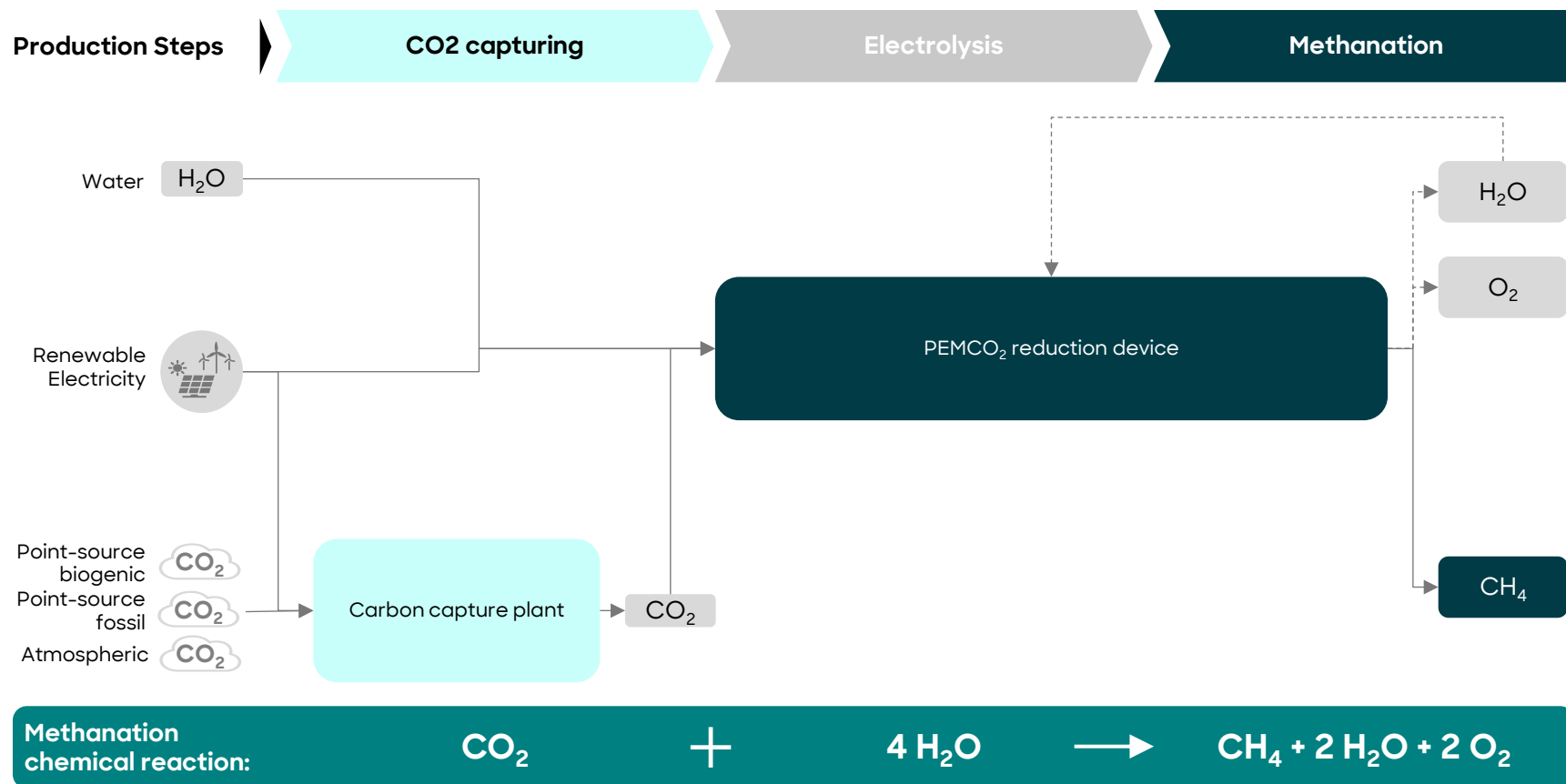
## Key parameter: Category

Category	Value
Technology maturity	Low
Methanation temperature [°C]	800
Overall process efficiency <sup>1)</sup> [%]	75-90%

1) Process efficiency describes the combined efficiency of the electrolysis and methanation step

# PEMCO<sub>2</sub> methanation uses a Polymer Electrolyte Membrane (PEM) to synthesize e-methane directly from water and CO<sub>2</sub> in one step

Technology deepdive: PEMCO<sub>2</sub> methanation



## Description

- **PEMCO<sub>2</sub> methanation** utilizes a Polymer Electrolyte Membrane (PEM) to **directly synthesize e-methane from water and CO<sub>2</sub>**
- The technology **lowers equipment costs** and **operates at moderate temperatures (60–80°C)**. It also eliminates the **need for precious metal cathodes** and **hydrogen procurement**
- A **pilot project has been launched** by Tokyo Gas, with **commercialization expected after 2040**

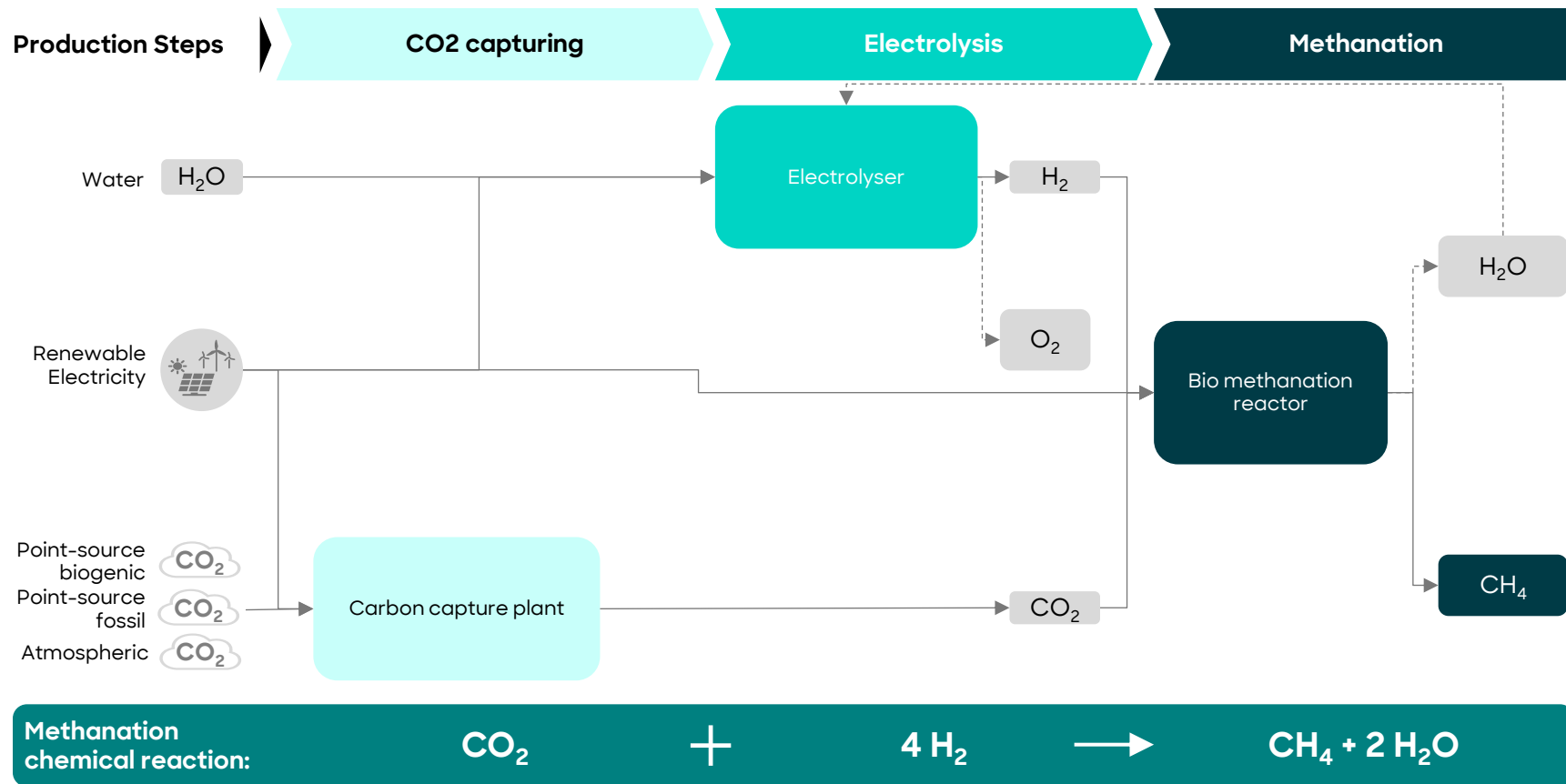
## Key parameter:

Category	Value
Technology maturity	Low
Methanation temperature [°C]	60–80
Overall process efficiency <sup>1)</sup> [%]	70–80%

1) Process efficiency describes the combined efficiency of the electrolysis and methanation step

# Biological methanation utilizes a two-step biochemical process where archaea act as biological catalysts to produce methane

Technology deepdive: Biological methanation



## Description

- Biological methanation employs a **two-step biochemical process** in which hydrogen is generated via electrolysis before archaea serve as biological catalysts to produce methane
- This method operates under **mild temperature and pressure conditions**
- However, **projected investment costs are higher** than those for Sabatier
- The **world's first demonstration plant** combining electrolysis and biological methanation was **established in Germany in 2015**

## Key parameter:

Category	Value
Technology maturity	Medium
Methanation temperature [°C]	35-65
Overall process efficiency <sup>1)</sup> [%]	60-65%

1) Process efficiency describes the combined efficiency of the electrolysis and methanation step. The efficiency of electrolysis is expected to be 76% by 2040



## **C. Forecasted renewable energy vector demand in NL**

# Energy demand estimates are based on I13050 report, developed by NL network companies to outline pathways to a climate-neutral energy system by 2050

## Introduction to the I13050 report



### Objective of the report

#### **I13050 aims to identify the key choices required to achieve a climate-neutral energy system by 2050**

- It provides insight into the energy infrastructure and flexibility measures required in the long term
- It addresses uncertainties in predicting future developments by using scenarios that represent realistic extremes of possible energy system outcomes



### Approach of the report

#### **I13050 uses scenarios to guide decisive policymaking**

- The energy transition is a major societal challenge, demanding rapid fossil fuel reduction, renewable energy growth, and systemic changes across key sectors
- Energy infrastructure (gas, electricity, and heat networks) must undergo significant transformation to meet future demands
- Scenarios help capture uncertainties and support informed decision-making for policymakers and stakeholders



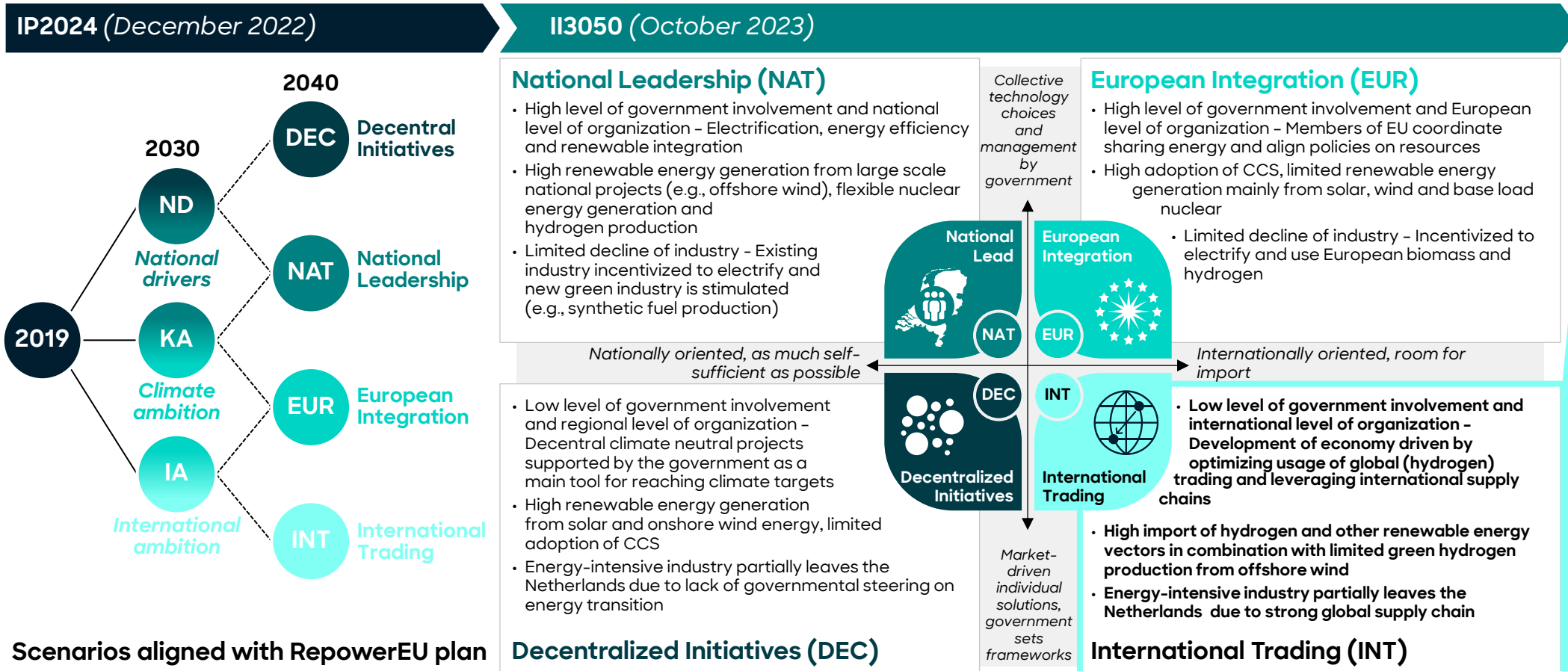
### Contributors

#### **I13050 was developed by several Dutch network companies and other relevant stakeholders**

- Network companies include: Alliander, Coteq, Enexis, Gasunie, Rendo, Stedin, TenneT, and Westlandinfra
- External experts, relevant industry associations, and government agencies provided input and consultation during the study

# II3050 report estimates the future energy demand across various scenarios - In this study the international trading scenario (INT) is the reference scenario

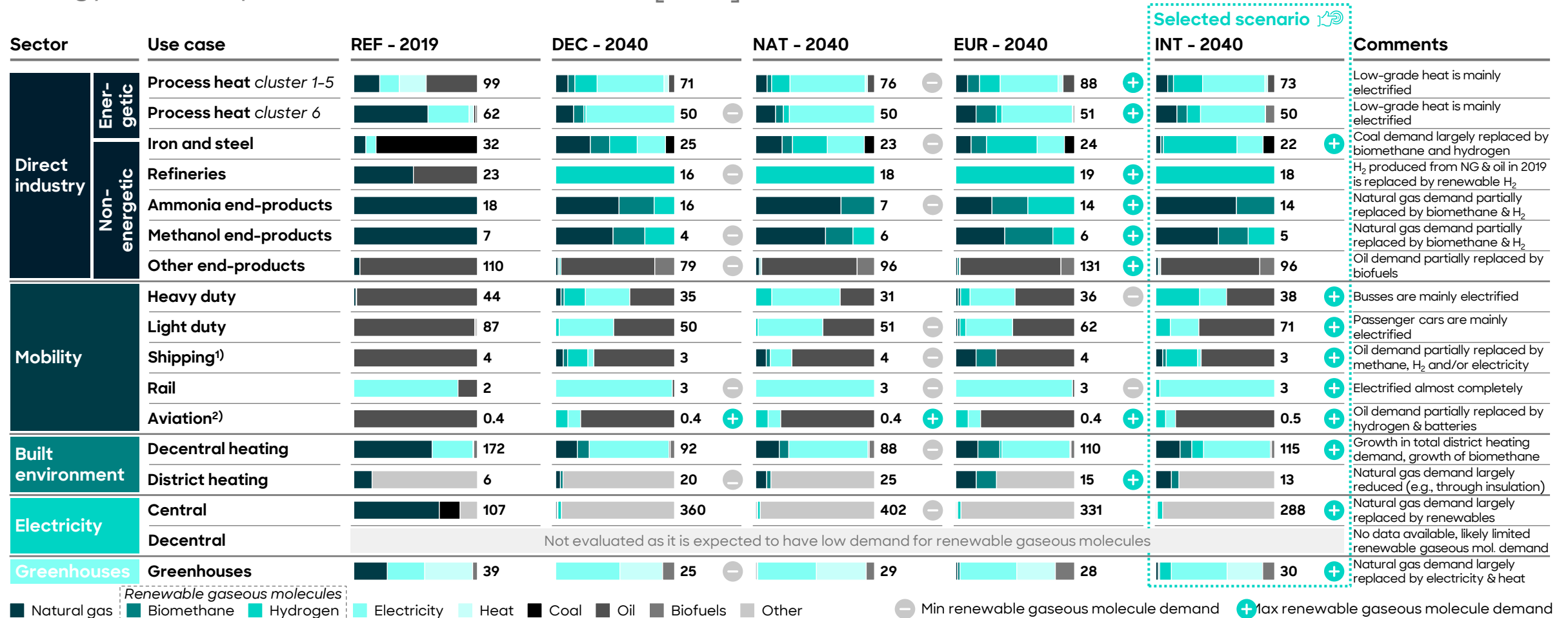
Scenarios used in II3050 report



The international trading (INT) scenario which is the reference for this study as it is expected that coordinated global efforts will be required due to the shared nature of the climate crisis

# The energy mix per use case is expected to change in the future - Each scenario from the I13050 report assumes a slightly different energy mix in 2040

Energy demand per use case - 2019 and 2040 [TWh]



Natural gas
  Biomethane
  Hydrogen
  Electricity
  Heat
  Coal
  Oil
  Biofuels
  Other
 ⊖ Min renewable gaseous molecule demand
⊕ Max renewable gaseous molecule demand

1) Excl. ~140 TWh forecasted demand for international bunkering of synthetic and biofuels in NL, based on IRENA report on decarbonizing the shipping sector, which estimates 8.5 EJ total global shipping demand in 2040 and 6% of global bunkering to be in the Netherlands; 2) Excl. ~45 TWh forecasted demand for synthetic aviation fuel (SAF) for international aviation in NL in 2050, based on INT scenario in I13050 report

# Different renewable energy vectors can be considered per use case to meet the demand for renewable gaseous molecules

Back-up – Rationale behind feasibility of renewable energy vectors per use case

Sector	Use case	E- Methane	Hydrogen	Ammonia	Methanol	
Direct industry	Energetic	Process heat cluster 1-5	✓ E-methane is used for mid to high grade heat processes	✓ Hydrogen is used for mid to high grade heat processes	✓ High NOx emissions make ammonia less feasible for NL, also challenges due to slow combustion	⊖ Lower energy density makes methanol less economically viable
		Process heat cluster 6	✓	✓	✓	⊖
	Non-energetic	Iron and steel	✓ E-methane can be used as input for DRI systems to reduce iron ore	✓ Hydrogen can be used as input for DRI systems to reduce iron ore	✗ Low maturity of ammonia for steel production, challenges due to NOx	✗ Low maturity of methanol for steel production
		Refineries	⊖ Reverting e-methane back into hydrogen (for potential further processing) is likely economically unviable	✓ Hydrogen is used for hydrocracking and desulfurization	✗ No direct use for ammonia as feedstock	✗ No direct use for methanol as feedstock
		Ammonia end-products	⊖	✓ Hydrogen is used for conversion into ammonia	✓ Ammonia can be directly imported rather converted on site from hydrogen	✗ No direct use for methanol in ammonia end-products
		Methanol end-products	⊖	✓ Hydrogen is used for conversion into methanol	✗ No direct use for ammonia in methanol end-products	✓ Methanol can be directly imported rather converted on site from hydrogen
Other end-products	✓ E-methane for producing other chemicals (oxo-chemicals, acetylene, ...)	✓ Hydrogen for producing other chemicals (bromine, hydrogen peroxide, ...)	✗ Limited / no use for ammonia in other chemicals	✗ Limited / no use for methanol in other chemicals		
Mobility	Heavy duty	✓ E-methane can be used in the form of CNG <sup>1)</sup> as fuel, niche use case for light duty as it is mostly electrified	⊖ Likely economically unviable compared to other sustainable options	✗ High toxicity, poor flame stability and high NOx emissions make ammonia likely challenging	✓ Methanol can directly be used as fuel, niche use case for light duty as it is mostly electrified	
	Light duty	✓	⊖	✗	✓	
	Shipping	✓ E-methane in the form of e-LNG can be used as direct fuel alternative	⊖ Not a likely option for domestic shipping in the Netherlands	✓ Not a likely option for domestic shipping in the Netherlands	✓ Methanol can be used as fuel alternative in specialized engines	
	Rail	⊖ Not a likely options for trains in the Netherlands, almost all electrified	⊖ Not a likely option for trains in the Netherlands, almost all electrified	✗ High toxicity, poor flame stability and high NOx emissions likely challenging	✗ No methanol powered trains operate, unlikely alternative	
	Aviation	✗ Use case e-methane in the form of CNG <sup>1)</sup> as fuel alternative too limited	✗ Hydrogen as a fuel alternative likely only suitable for niche applications	✗ Use case ammonia as fuel alternative too limited	✗ Use case methanol as fuel alternative too limited	
Built environment	Decentral heating	✓ E-methane can (directly) be used as input for methane / hybrid heat boilers	✓ Hydrogen can be used as input for hydrogen / hybrid heat boilers	✗ High toxicity and poor flame stability require specially designed / modified boilers, therefore likely challenging, also NOx challenges	✗ Toxicity and potential formaldehyde emissions require specially designed / modified boilers, therefore likely challenging	
	District heating	✓	✓	✗	✗	
Electricity	Central	✓ E-methane can be used as input for methane power plants	✓ Hydrogen can be used as input for hydrogen power plants	✓ Potential in co-firing with coal & high NOx emissions, limited use case in the Netherlands	⊖ Low energy density makes methanol less economically feasible	
	Decentral	Not evaluated as it is expected to have low demand for renewable gaseous molecules				
Greenhouses	Greenhouses	✓ Methane can be used as input for boilers - Potential for CO <sub>2</sub> enrichment	✓ Hydrogen can be used as input for boilers	✗ Challenges as high toxicity and poor flame stability demand specialized boilers, and NOx emissions	✗ Challenges as high toxicity and poor flame stability demand specialized boilers	

Considered as a feasible option: ✓

Not considered: ⊖

✓ Likely not a feasible option for NL

⊖ Likely not economically viable

✗ Not technologically proven or low maturity, feasible only for niche applications

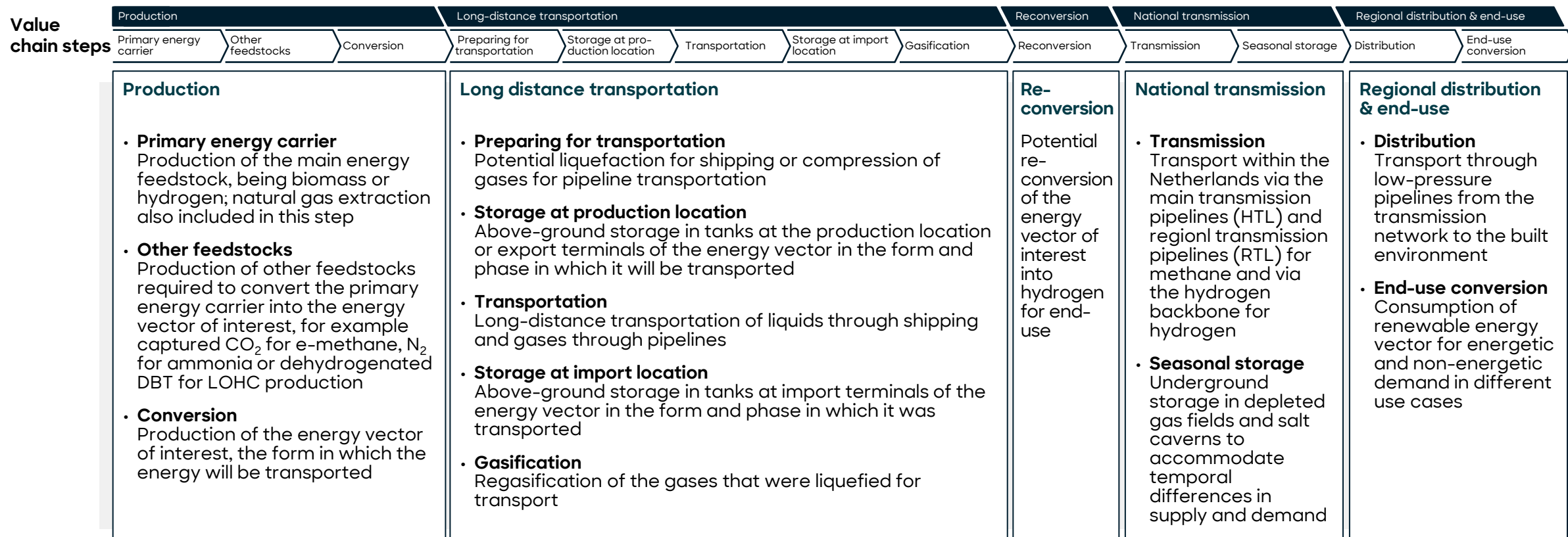
1) Compressed natural gas



## **D. Value chain quantification of renewable energy vectors**

# Study focuses on the entire value chain from production to transportation to distribution and end-use

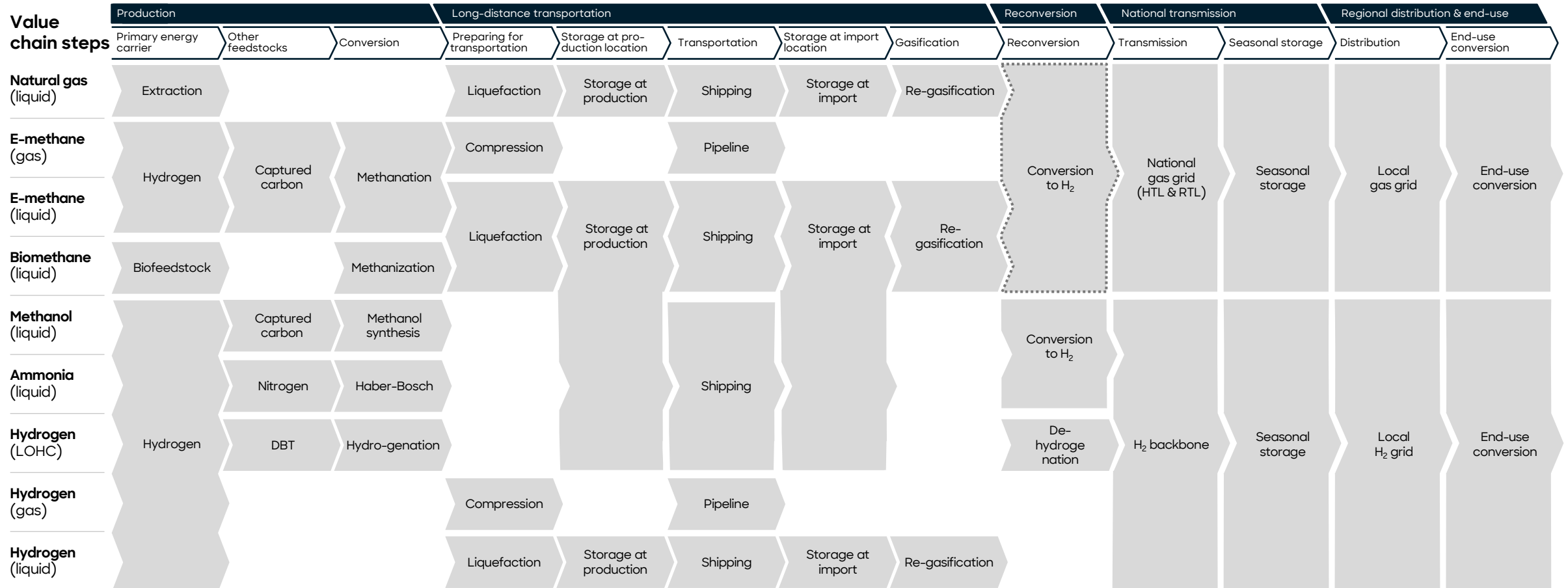
## Renewable energy vector value chain descriptions (1/2)



Draft

# For the shortlisted end-use cases, different energy vectors have been mapped across the entire value chain

## Renewable energy vector value chain descriptions (2/2)



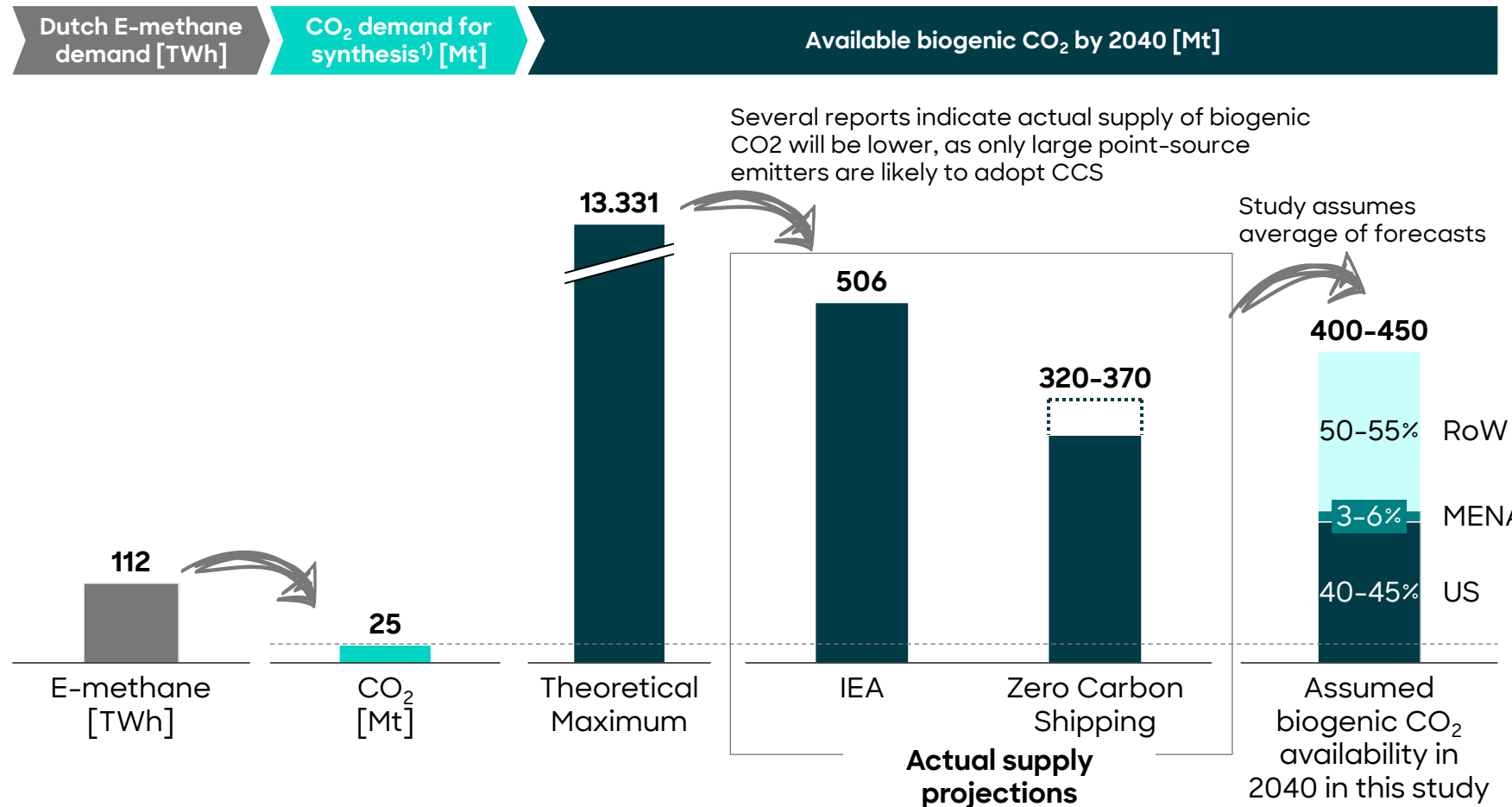
Optional steps



## **E. Biogenic CO<sub>2</sub> availability**

# Supply of biogenic CO<sub>2</sub> will be limited as just the Dutch demand for e-methane would require ~13% of total available biogenic CO<sub>2</sub> of the US or ~150% of MENA

Availability of biogenic CO<sub>2</sub> in 2040 [Mt]



## Key takeaways

- Synthesizing the projected Dutch E-methane demand for 2040 requires approximately 25 Mt of CO<sub>2</sub>
- By 2040, 400-450 Mt of biogenic CO<sub>2</sub> is expected to be captured and available for use
- Meeting Dutch E-methane needs would claim ~6% of global biogenic CO<sub>2</sub> – disproportionate for its energy demand under 1% of the global total. Moreover, other sectors might outcompete the demand for e-methane production
- Meeting the entire Dutch E-methane demand through imports from specific regions would require ~13% of the available biogenic CO<sub>2</sub> of the US or ~150% of MENA

1) Assuming a 90% capture rate efficiency



## F. Challenges

# Challenges

The transition to a low-carbon energy system presents an array of challenges. In this chapter, we focus on the most critical challenges related to e-methane. Our aim here is to provide a more nuanced understanding of e-methane's potential and its limitations as an emerging technology to decarbonize future energy usage. First, we will focus on challenges that are solely related to e-methane, after which we will end with challenges that are also related to all new emerging energy carriers.

## Technical and Productional

E-methane has a number of technical and productional challenges. Two are related to the Technical Readiness Levels (TRL) of this energy carrier. First of all, DAC technology is at the moment not fully mature (see also Chapter 5). Secondly, the production of e-methane is currently still at pilot-level quantities, while upscaling to large production quantities will probably be complex.

Other challenges relate to the production efficiency of e-methane. Like most physical and chemical conversions from one product into another the combination of electrolyser, DAC and methanation is energy intensive. This challenge is described in Chapter 4 (Figure 11) of the report.

Furthermore, when producing e-methane losses can occur. These losses might lead to the preference of direct use of hydrogen instead of adding another conversion step for producing e-methane.

## Economics and Financial

The question whether e-methane will succeed in terms of being adopted by end-users will for an important part be a matter of its economics. In the end, the economics decide on e-methane's competitiveness in relation to competing energy carriers.

This study shows on the one hand that e-methane may turn out to be twice as expensive to produce in 2040 compared to biomethane. At the same time natural gas (including CCS) will be even less expensive than biomethane. So, when comparing low carbon gases, e-methane is the least competitive. However, biomethane will not be abundantly available in the future and natural gas including CCS does not contribute to the aim of reaching the 2050 climate goals.

Chapter 6 indicates that for the selected use cases, the CAPEX intensity of meeting hydrogen demand in NL is, at least, three times higher than that of e-methane. One could therefore argue that economically e-methane must become the energy carrier of choice for certain cases. However, policy makers and end-users have to make decisions today for the energy landscape of tomorrow. As long as industrial companies have no feasibility of e-methane being abundantly available ten or twenty years from now, these companies may choose a different path. This path may be, with equivalent uncertainties about availability, hydrogen. Uncertainty regarding the ultimate costs of DAC is another uncertain factor companies have to deal with. If the costs of DAC would turn out twice as high, the electricity sector and cluster 6 would perhaps be better off using hydrogen instead of e-methane.

# Challenges

The transition to a low-carbon energy system presents an array of challenges. In this chapter, we focus on the most critical challenges related to e-methane. Our aim here is to provide a more nuanced understanding of e-methane's potential and its limitations as an emerging technology to decarbonize future energy usage. First, we will focus on challenges that are solely related to e-methane, after which we will end with challenges that are also related to all new emerging energy carriers.

## Societal acceptance and sustainability

Accepting the idea that e-methane could in the future be a sustainable energy carrier, by policy makers as well as the public in general, is crucial for e-methane to be adopted. For biomethane and e-methane, like with natural gas, methane leakage is the biggest challenge. We are only at the beginning of understanding the current scale of methane leakage but, specifically during natural gas production, scope 1 emissions appear to be substantial. Potential e-methane emissions in the supply chain; during production, transportation or as a result of an asset being dismantled would hurt the image of e-methane as a zero-footprint energy carrier. In this respect it is important to note that in this study the production of e-methane results in scope 2 emissions via the CO<sub>2</sub> grid intensity for the electricity that is used for DAC. A potential lack of confidence by policy makers and/or end-users that e-methane will be a zero-footprint energy carrier in the future might hinder its adoption. It will take substantial efforts in terms of adopting global standards and convincing interest groups to tackle this issue.

Another element that could affect public perception negatively is the supposed lock-in for natural gas. This means that the public sees synthetic renewable fuels as a reason for the continuation of the fossil fuel-based infrastructure. Policy makers and end-users aim for the transition to sustainable energy carriers. Interest groups will argue that in a situation where energy carriers are still being dependent on the fossil fuel-based infrastructure the transition to sustainable energy carriers is delayed or even thwarted. One can argue however that no lock-in risk exists because phasing out fossil fuels is the only direction to go in order to tackle climate change. Continued and reuse of current fossil infrastructure for renewable energy sources like e-methane is evidently an opportunity and not a risk.

The transition to a low-carbon energy system presents an array of challenges. In this chapter, we focus on the most critical challenges related to e-methane. Our aim here is to provide a more nuanced understanding of e-methane's potential and its limitations as an emerging technology to decarbonize future energy usage. First, we will focus on challenges that are solely related to e-methane, after which we will end with challenges that are also related to all new emerging energy carriers.

## Challenges related to all new emerging energy carriers

The study contains many assumptions on the speed of development of technologies and the future costs associated with the production and transportation of e-methane. This is especially true for the costs and the grid intensity related to DAC. This makes the outcome of the future costs of e-methane for end-users uncertain as well as e-methane's competitiveness (relative costs) against other energy carriers. Whatever the future costs of e-methane, in general it is clear that electrification of all end-users and industries is not a viable alternative.

A major hurdle for all new emerging energy carriers such as hydrogen and e-methane is the establishment of robust carbon accounting and certification systems which is a requirement under the Renewable Energy Directive (REDII and the forthcoming REDIII revisions). Ensuring the carbon neutrality of e-methane requires reliable methods for measuring, reporting, and verifying (MRV) emissions throughout its life cycle. Although progress has been made, these systems remain underdeveloped. This also applies to countries outside Europe, for example in the case that e-methane is sourced from MENA.

Another critical issue is the inconsistency of policy incentives. While government interventions through mechanisms like carbon pricing, taxes, and subsidies are vital to make e-methane competitive with fossil fuels, such incentives vary widely across the European Union and its member states. This disparity creates market imbalances, discourages private investment, and complicates the development of a unified European approach to e-methane adoption.

The lack of global standardization is an uncertainty for all energy carriers. Without internationally agreed-upon standards for production, quality, and sustainability criteria, cross-border trade in e-methane may be hindered. This lack of alignment affects not only the feasibility of international market integration but also the harmonization of decarbonization goals and the realization of large-scale ambitions.

Permitting and environmental regulations present a significant challenge. Securing permits for the construction of e-methane production facilities, green hydrogen and DAC is often a lengthy and complex process, influenced by strict environmental regulations. These delays can increase project costs and slow the pace of scaling up production, undermining the role of e-methane in the energy transition.



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