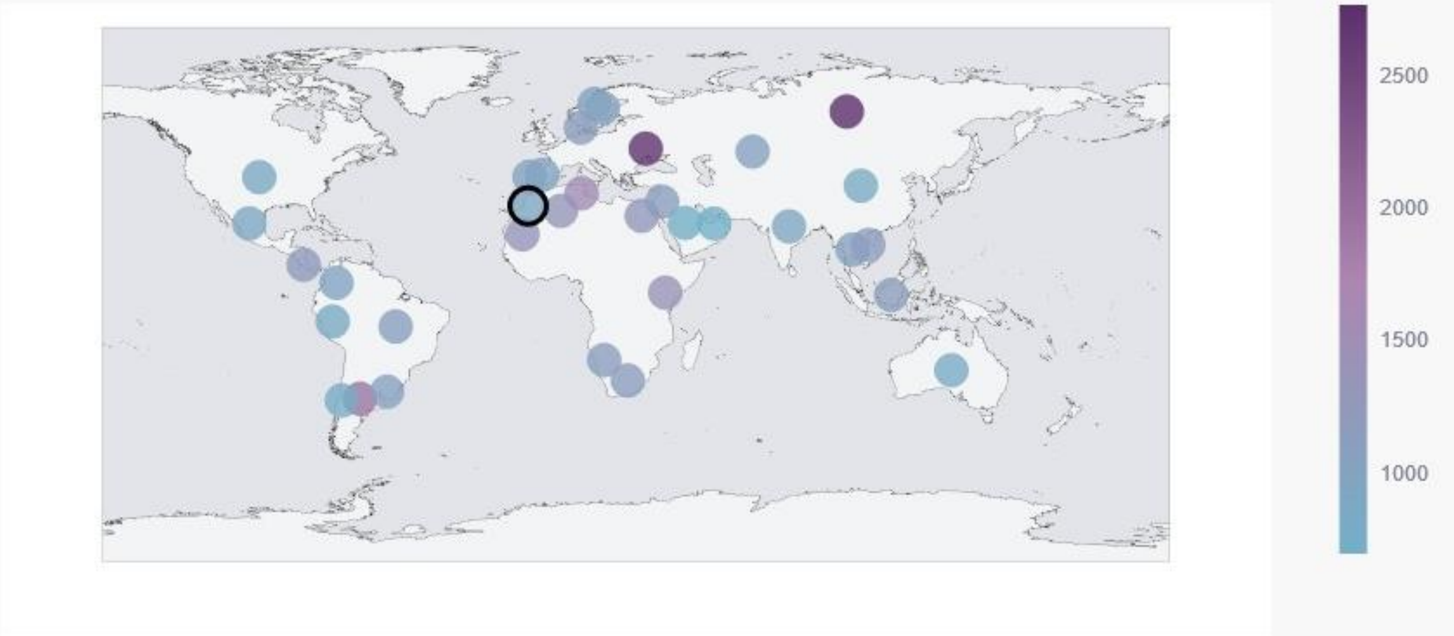

PTX Business Opportunity Analyser (BOA): Data Documentation for Version 2.0

Documentation of data sources and data processing

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Abstract

// **The goal of this document** is to give insights into calculations, sources and methods underlying the data used in the PTX BOA tool. Key data points can be accessed in the PTX Business Opportunity Analyser (BOA) tool itself.

Citation details

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Further information

// Link to the PTX BOA website for the tool and further information:

https://www.agora-industry.org/data-tools/ptx-business-opportunity-analyser-new

Contents

1 Abbreviations

AEL	Alkaline electrolysis
ATR	Autothermal reactor
CAPEX	Capital expenses
DAC	Direct air capture
DBT	Dibenzyltoluol (a possible LOHC)
DRI	Direct reduced iron
EAF	Electric arc furnace
FLH	Full load hours
FT	Fischer-Tropsch
HBI	Hot briquetted iron
HFO	Heavy fuel oil
LCOH	Levelized cost of hydrogen
LHV	Lower heating value
LNG	Liquefied natural gas
LOHC	Liquid organic hydrogen carriers
OPEX	Operational expenditure
PEM	Proton exchange membrane electrolysis
PTX	Power-to-X
PV	Photovoltaic
RES-E	Renewable energy source electricity
RWGS	Reverse water gas shift
SMCR	Specified maximum continuous rating
SOEC	Solid oxide electrolyser cell
VOM	Variable operation and maintenance costs
WACC	Weighted costs of capital

2 Central assumption of the tool - what's in, what's out?

This section provides information on key points in our assumptions that should be kept in mind when interpreting the results of the tool. In each process step, we list **important aspects of what is included in our calculations and/or assumptions and what is not.**

Note that this overview is not comprehensive in the sense that it shows all assumptions at one glance. Rather, the points listed are aspects that have emerged in discussions with stakeholders (deep-dive country workshops) prior to the publication of the tool and which helps in understanding and using the tool.

Table 2-1: Central assumptions of the tool – what's in, what's out?

Considered in the tool	**Not considered in the tool**
General	
Costs (in USD/kWh or USD/t)	**Production potentials** (in TWh/a or t/a)
The tool calculates **landing costs of various PTX products**	
The tool **calculates (as intermediary steps)**: • Levelized costs of electricity • Levelized costs of hydrogen • Costs of CO_2 *via* DAC • Costs of water *via* sea water desalination • Costs of pre- and post-processing for transport • Costs of ship transport and buffer storage at the harbors These values are calculated internally, but not reported externally	The tool uses **final costs from literature** on: • Costs for pipeline transport per km
Values for **WACC are country-specific**	The tool **does not include by default a reconversion to hydrogen as landing product**: the costs refer to the selected PTX product which is landed in the demand country in the respective molecule form (except for LOHC)
Optimization of capacities: Tool optimizes investments in capacities and full load hours to minimize landing costs of PTX product	The tool is **not GIS-based**: calculations do not include analysis of spatially referenced geo-data
Electricity generation (RES-E generation)	
Values for **CAPEX are country-specific for PV and Onshore Wind** based on real projected costs	Costs of **electricity transmission are not included**
CAPEX is reduced over time for RES-E based on global learning curves	
Values for **OPEX are country-specific for all RES-E technologies** in the tool	
Values for **full load hours are country and technology-specific**	
The tool uses **uniform lifetime data** for RES-E, electrolysis and derivative technologies for all countries	
Electrolysis	
The tool generates **own calculations of levelized costs of water input for electrolysis**: costs for water input are calculated in the tool based on water desalination data	
CAPEX includes reinvestments into the stack	
The tool uses **specific efficiencies for different electrolysis technologies** including learning curves over time from literature	
Derivative Production	
The tool generates **own calculations of levelized costs for CO_2 inputs**: Levelized costs of CO_2 – if needed – are calculated in the tool based on DAC	**Possible need for heat storage is not included.**

Costs for heat – if needed – are specified, based on data from the literature	
The tool uses **specific efficiencies for different derivative production technologies** including learning curves over time from literature	
Transport	
The tool includes **costs for transport activities outside the supply country** (transport activities *via* ship or pipeline)	The tool does not include **costs for transport activities within the supply country** • e.g.transport of RES-E from production site to electrolysis • e.g.transport from electrolysis to port/LNG terminal/pipeline starting point
Pipeline transport is assumed to be feasible (for hydrogen and methane) for transport distances < 6000km	The tool does not include **costs to build new, currently not existing export infrastructure** (e.g. ports)
The tool uses **different cost assumptions for various pipeline options:** • New / retrofitted pipelines (repurpose option is set by default only if there is already an existing pipeline connection) • Land / sea pipelines	

3 Renewable Energy Electricity

The PTX BOA offers a range **of four RES-E sources for the electrolysis process**:

- PV tilted
- Wind onshore
- Wind offshore
- Wind-PV Hybrid

For these RES-E options, the **primary data source utilised for obtaining data related to CAPEX and OPEX is the annual publication titled "Renewable Power Generation Costs" by IRENA (IRENA 2023)**. This publication serves as our principal reference.

This source solely present actual data from existing projects and do not include any projections. Consequently, we have additionally incorporated learning curves specific to RES-E technologies, as described below.

3.1 CAPEX[1]

Within the aforementioned report IRENA (2023), the term "total installed project costs" has been used instead of "CAPEX," without explicitly specifying whether financing costs are included. On the one hand it has been stated that total installed project costs also include "[…] fixed financing costs" (IRENA 2022, p. 180). On the other hand, for offshore wind costs it has been stated that: "*Offshore, turbines (including towers) generally account for between 33% and 43% of the total installed cost (Figure 4.7). Other costs, however – including installation, foundations and electrical interconnection – are significant, and take up a sizeable share of the total installed costs. Installation costs, for the estimates available, range from 8% to 19% of total installed costs, while contingency/other costs range between 10% and 14%, electrical interconnection between 8% and 24% and foundation costs between 14% and 22%. Development costs, which include planning, project management and other administrative costs, comprise 2% to 7% of total installed cost*" (IRENA 2022, p. 110). No financing costs are mentioned here. Furthermore, on page 73, it has been stated that "*[t]he LCOE of an onshore wind farm is determined by the total installed costs, lifetime capacity factor, O&M costs, the economic lifetime of the project, and the cost of capital*" (IRENA 2022, p. 73).

Therefore, **we have chosen to interpret the "total installed project costs" as CAPEX excluding financing costs for Wind Offshore and Wind Onshore.** The IRENA report, however, provides a detailed costs breakdown for utility PV generation. For PV we therefore have subtracted parts of the 'soft costs' which includes the financing costs.

To tackle the missing projections problem, **we projected the 2022 data described in the sections above by using cost reduction rates from the National Renewable Energy Laboratory (NREL)[2].**

Finale Data is shown in Annex I: CAPEX Data for RES-E per country**.**

[1] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

[2] https://atb.nrel.gov/electricity/2023/technologies accessed 04.04.2024

3.1.1 PV tilted

Data for CAPEX have been taken from IRENA (2023). To make sure this data is comparable to the data for wind projects, we have chosen to subtract the cost components “margin” and “financing costs”. Financing costs are integrated independently in our PTX BOA tool and the margin should not be included within our tool as we focus on costs of an integrated PTX production facility.

This way we gathered data for about half of the countries that are relevant for the PTX BOA. In instances where data was unavailable for a particular country, but accessible for other countries within the same region (e.g., Central America), we have chosen to use the average value of the available country data within this region.

The data points obtained have then been projected for the years 2030 and 2040 by using the NREL cost reduction projections for utility-scale PV[3].

Table 3-1: Cost reduction over time for PV CAPEX

	Cost reduction		
	Solar Utility PV		
	Advanced	Moderate	Conservative
2022-2030	33%	24%	12%
2030-2040	35%	26%	16%

Source: own calculations based on NREL https://atb.nrel.gov/electricity/2023/utility-scale_pv

The final data used within the PTX BOA is displayed across all supply countries in Annex I.

3.1.2 Wind onshore

In line with the data obtained for PV, **weighted average total installed costs for wind onshore projects in 2022** have been depicted from IRENA (2023)

If countries we want to cover in the PTX BOA weren’t covered with the previous approaches, we have taken regional data IRENA (2023).

The data points obtained have then been projected for the years 2030 and 2040 by using the NREL cost reduction projections for onshore wind[4].

Table 3-2: Cost reduction over time for wind onshore CAPEX

	Cost reduction		
	Onshore wind		
	Advanced	Moderate	Conservative
2022-2030	29%	25%	18%
2030-2040	11%	10%	7%

Source: own calculations based on NREL https://atb.nrel.gov/electricity/2023/land-based_wind

[3] https://atb.nrel.gov/electricity/2023/utility-scale_pv accessed on 04.04.2024
[4] https://atb.nrel.gov/electricity/2023/land-based_wind accessed on 04.04.2024

The final data used within the PTX BOA is displayed across all supply countries in Annex I.

3.1.3 Wind offshore

The European and the Asian offshore wind markets are the only mature wind offshore markets worldwide. Therefore IRENA (2023) does only provide data on European countries, China, Japan and Korea. **For the PTX BOA countries China and Denmark we used country-specific data.**

For all other countries, we assume that the worldwide average total installed project costs would be applicable.

The data points obtained have then been projected for the years 2030 and 2040 by using the NREL cost reduction projections for offshore wind[5].

Table 3-3: Cost reduction over time for wind offshore CAPEX

	Cost reduction		
	Offshore wind		
	Advanced	Moderate	Conservative
2022-2030	27%	25%	20%
2030-2040	11%	9%	6%

Source: own calculations based on NREL https://atb.nrel.gov/electricity/2023/offshore_wind

The final data used within the PTX BOA is displayed across all supply countries in Annex I.

3.1.4 PV-Wind-Hybrid

For hybrid power plants we assume a combination of PV and wind power plants. Consequently, the CAPEX is a combination (depending on the share of capacity of each technology) of the PV titled and Wind Onshore CAPEX as stated in the previous sections.

3.2 OPEX[6]

IRENA (2022) indicates OPEX costs for Wind Offshore, Wind Onshore and PV. From the various data points that are included in this IRENA publication, we have depicted values that seem to cover the average of all bandwidths described:

- **PV tilted:** 14.1 $US\$_{2021}$/kW
- **Wind Onshore:** 45 $US\$_{2021}$/kW
- **Wind Offshore:** 94 $US\$_{2021}$/kW

However, for the PTX BOA we need OPEX values that are a percentage of CAPEX. **Referring to the 2021 CAPEX data, the OPEX values from IRENA therefore transform into:**

- **PV:** **1.7% of CAPEX** (average of PTX BOA countries)

[5] https://atb.nrel.gov/electricity/2023/offshore_wind accessed on 04.04.2024
[6] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

- **Wind Onshore:** **2.8% of CAPEX** (average of PTX BOA countries)
- **Wind Offshore:** **3.4% of CAPEX** (average of PTX BOA countries)

3.3 Lifetime of RES-E technologies

For wind onshore as well as offshore installations, data on lifetime is based on the DNV GL Standard "Lifetime extension of wind turbines" (DNVGL-ST-0262; state of march 2016). Here, a lifetime of **20 years for wind power** is suggested: "When designing wind turbines, a design lifetime of 20 years is generally assumed as a basis for dimensioning."

For **PV installations we assume a lifetime of also 20 years** as product guarantees from many manufacturers cover this timespan.

4 Electrolysis

A central cost component of hydrogen and derivative costs lies in the electrolysis process. Electrolysis can take place with the use of different electrolyser technologies. In the PTX BOA, you can choose between **three types of electrolysis processes:**

- Alkaline electrolysis (AEL)
- Proton exchange membrane electrolysis (PEM)
- High temperature electrolysis: Solid oxide electrolyser cell (SOEC)

4.1 Water usage for electrolysis

Water consumption for electrolysis is assumed to be 10.11 kg water per kg of hydrogen produced. This data is based on Kuckshinrichs et al. (2017) and is in line with data used for the "Agora LCOH database" (Agora Energiewende 2023a).

4.2 Alkaline electrolysis (AEL) and Proton exchange membrane (PEM) electrolysis

4.2.1 CAPEX[7] and lifetimes

Data on CAPEX is based on research conducted by Agora Energiewende (Agora Energiewende 2023b). When calculating CAPEX costs of electrolysers, it is necessary to consider the replacement of the stack which has a significantly lower lifetime compared to the rest of the electrolysis plant[8]. **For the PTX BOA we assume an overall lifetime of 20 years for the electrolysis plant** (Fraunhofer ISE; E4Tech; Fraunhofer IPA 2018).

Table 4-1: CAPEX of AEL and PEM electrolysis

	Unit		2030	2040
Stack replacement [fraction of CAPEX]		AEL	0.26	0.24
		PEM	0.25	0.23
Total CAPEX (including replacement of stack after 10 years)	USD_{2021}/kW_{H2}	AEL	1,049	747
		PEM	1,225	931

Source: own compilation based on data from (Agora Energiewende 2023b)

4.2.2 OPEX

For both AEL and PEM electrolysis we assume 2% of OPEX as a fraction of CAPEX per year based on Agora LCOH database (Agora Energiewende 2023b).

[7] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

[8] In case of an overall lifetime of 20 years for the electrolysis plant, (Agora Energiewende 2023b)assumes a stack lifetime of 10 years.

4.2.3 Efficiency

Efficiency of electrolysis is based on data from IEA (2021). However, the report does not differentiate between AEL or PEM. According to IRENA (2020), AEL electrolysers are slightly more efficient compared to PEM.

Based on the efficiency range between AEL and PEM electrolysis presented by IRENA (2020) for 2020 and 2050, we have chosen to use the values from IEA (2021) for AEL electrolysis and reduce the values for PEM by 2% for 2030 and 1% for 2040.

This leads to the following efficiency assumptions:

- **PEM:** 67% (2030) and 71% (2040)
- **AEL:** 69% (2030) and 72% (2040)

4.3 High temperature electrolysis (Solid oxide electrolyser cell (SOEC))

Compared to AEL or PEM electrolysers, SOEC (solid oxide electrolyser) is a technology still in development. Therefore, most literature sources that provide CAPEX data for electrolysers do not provide data for SOEC technologies.

4.3.1 Overall and stack lifetime

Overall lifetime of the plant is assumed to be 20 years (Fraunhofer ISE; E4Tech; Fraunhofer IPA 2018). **The stack lifetime is assumed to be between 20,000 and 40,000 hours in 2030** (Guidehouse 2021) **and between 20,000 and 90,000 hours in 2040** (Patonia and Poudineh 2022). We calculated an average stack lifetime of 5 years (scenario 2030) and 10 years (scenario 2040) by assuming 6,500 full load hours for the electrolyser.

4.3.2 CAPEX[9]

For the data year 2030, our literature review showed that the highest CAPEX amounts to 1,477 [€/kW] (Prognos 2020). This value has been selected to represent the “high” cost pathway in our study. We have chosen to use 1,000 [€/kW] from the Guidehouse (2021) for the “low” cost pathway. We have calculated the midpoint between those two values for the “medium” cost pathway.

For the data year 2040, we used the value of 1,123 [€/kW] (Prognos (2020) for the cost pathway “high” and 800 [€/kW] (Fraunhofer ISE; E4Tech; Fraunhofer IPA (2018)) for the cost pathway “low”. Again, we have calculated the midpoint between those two values for the cost pathway “medium”.

However, this data only includes a one off investment and does not include the lower stack lifetime (5 years in 2030 and 10 years in 2040) compared to the overall lifetime (20 years) of the plant. Therefore, the CAPEX for replacing the stack must be considered. The CAPEX share for the stack is assumed to be 30% (Patonia and Poudineh 2022). Thus, this share is multiplied by the CAPEX data for the overall plant. This CAPEX for the stack must be reinvested several times during the

[9] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

lifetime of the plant (overall lifetime of plant divided by stack lifetime minus 1, as the first overall investment includes the stack).

As a result, the following CAPEX data is calculated and used as input into the tool.

Table 4-2: CAPEX for SOEC electrolysis including stack replacement costs

Final data	year	Final unit	Final Value	Main source
Cost pathway "high"	2030	USD_{2021}/kW_{H2}	4,678	Prognos 2020
Cost pathway "medium"	2030		3,879	Average between high and low
Cost pathway "low"	2030		3,080	Guidehouse 2021
Cost pathway "high"	2040		2,297	Prognos 2020
Cost pathway "medium"	2040		1,972	average between high and low
Cost pathway "low"	2040		1,646	Fraunhofer ISE; E4Tech; Fraunhofer IPA 2018

4.3.3 OPEX

OPEX costs are assumed to be 3% of overall CAPEX (Fraunhofer ISE; E4Tech; Fraunhofer IPA 2018, Figure ABB A-9).

4.3.4 Efficiency

We assume for 2030 an efficiency of 73% and for 2040 of 77% (own calculations based on Prognos 2020; Guidehouse 2021 and Patonia and Poudineh 2022).

5 PTX derivative production

The techno-economic data provided in this section describes the production of hydrogen derivates downstream of the electrolysis unit.

Note, however, that the following processes associated with PTX derivative production are not covered in this section, but are detailed separately in further chapters:

- **Hydrogen and derivative storage**, which might be necessary to ensure a smooth operation and increase capacity utilisation, are treated separate from the derivative production itself. Implementation is discussed in section 10.
- **Supply of carbon**, e.g. *via* Direct air capture (DAC), is treated as an individual transformation step. This way, the user can choose between DAC and point-source carbon supply. Implementation is described in section 9.2

5.1 Methanation (Sabatier process)

Methanation *via* the Sabatier process is technically demonstrated. Hydrogen and carbon dioxide react in a fixed bed reactor to synthetic methane. The process is exothermal.

For representing the process, we rely on the following two studies:

- **Oeko-Institut (2020)** provides techno-economic data projections based on a review of recent literature, among others: Agora Energiewende; Agora Verkehrswende; Frontier Economics (2018), Fasihi et al. (2016), Fasihi and Breyer (2017), Fasihi et al. (2017), Fasihi and Breyer (2018), LBST; dena (2017). Two cost scenarios are included: "continuity" and "break-through". We use Oeko-Institut (2020) "continuity" scenario as the main source for the transformation plant costs.
- **Fasihi and Breyer (2018)** includes energy and mass flow diagrams for the overall transformation process.

Data used as input into the tool is show in Table 5-1 and described in detail in the following subsections.

Table 5-1: Techno-economic data for Methanation plants

Parameter	Unit	2020	2030	2040
CAPEX[10]	USD_{2021}/kW	719	628	481
OPEX	%CAPEX p.a.	3	3	3
Lifetime	Years	30	30	30
Efficiency	kWh CH_4/kWh H_2	0.83	0.83	0.83
CO_2 demand	Kg CO_2/kWh CH_4	0.178	0.178	0.178
Excess heat (w/o DAC)	kWh_{th}/ kWh CH_4	0.185	0.185	0.185
Excess water (w/o DAC)	Kg H_2O/kWh CH_4	0.143	0.143	0.143

Source: Oeko-Institut (2020), Fasihi and Breyer (2018)

5.1.1 CAPEX[11]

Capital costs are based on the “continuity” scenario in Oeko-Institut (2020), Table 2.8, and transformed to USD_{2021}.

5.1.2 OPEX

Operational costs are based on the “continuity” scenario in Oeko-Institut (2020), Table 2.8.

5.1.3 Lifetime

Plant lifetimes are based on the “continuity” scenario in Oeko-Institut (2020), Table 2.8.

5.1.4 Efficiency and conversion

The efficiency of H_2 to CH_4 conversion and the CO_2-demand is adopted from Oeko-Institut (2020). The efficiency is based on the lower heating value of hydrogen.

5.1.5 Energy demand

Excess heat: the Sabatier process is exothermic. Part of the excess heat can be used to operate an on-site DAC plant. The amount of excess heat in Table 5-1 is derived from an energy and mass flow diagram in Fasihi and Breyer (2018).

The same diagram in Fasihi and Breyer (2018) is used to derive the **amount of water production from the Sabatier process.**

[10] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

[11] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

5.2 Fischer-Tropsch process (FT e-fuels synthesis)

The Fischer-Tropsch process is well established regarding fossil carbon sources. A syngas of carbon monoxide and hydrogen reacts in a (cobalt) fixed bed reactor to crude waxes, which are further transformed to various hydrocarbon fractions in a hydrocracker. The Fischer-Tropsch process is exothermal.

The syngas generation from carbon dioxide and hydrogen is demonstrated on smaller scale. Most literature considers production of syngas in a reverse water gas shift (RWGS) reactor. Schemme et al. (2020) rate the Fischer-Tropsch process via RWGS with TRL= 6.

RWGS requires high temperature heat, which can be provided by combustion of light flue gases from Fischer-Tropsch synthesis or by electric means. We take the electricity demand for RWGS heat supply into account, thus, opting for an emission-free alternative of the transformation process.

Co-electrolysis is another option of syngas production demonstrated on smaller scale. The reverse water gas shift reaction from CO_2 to CO takes place in the same reactor as the electrolysis of water to hydrogen (under high temperatures). Though promising reduced plant capacities, the technical readiness of Co-electrolysis is still relatively low. Ausfelder and Dura (2018) name TRL= 3. In addition, techno-economic data is scarce.

We choose the transformation to synthetic Kerosene and Diesel to consist of three process steps: RWGS reactor, Fischer-Tropsch reactor, hydrocracker.

For representing the process, we rely on the following studies:

- **Frontier Economics (2021)** provides techno-economic data on the production of PtL-fuels. The authors focus on the year 2020, however capital costs are distinguished for smaller and larger plant sizes.
- **Oeko-Institut (2020):** as above (Section 5.1)
- **Schemme et al. (2020) and Schemme (2020) (PhD Thesis)** give detailed insights into various hydrocarbon production technologies. A process is suggested that provides electric heating of the RWGS unit, hence, avoiding emissions from high-temperature heat supply by combustion.
- **Ausfelder and Dura (2018)** provide techno-economic data for the Fischer-Tropsch-route via co-electrolysis.
- **Fasihi and Breyer (2018):** as above (Section 5.1)

Data used as input into the tool is show in Table 5-2 and described in detail in the following subsections.

Table 5-2: Techno-economic data for Fischer-Tropsch plants

Parameter	Unit	2020	2030	2040
CAPEX[12]	USD_{2021}/kW	727	623	459
OPEX	%CAPEX p.a.	3	3	3
Lifetime	Years	30	30	30
Efficiency	kWh CH_x/kWh H_2	0.73	0.73	0.73
CO_2 demand	kgCO_2/kWh CH_x	0.265	0.265	0.265
Electricity demand	kWh_{el}/ kWh CH_x	0.086	0.086	0.086
Excess heat (w/o DAC)	kWh_{th}/ kWh CH_x	0.404	0.404	0.404
Excess water (w DAC)	kg H_2O/kWh CH_x	0.248	0.248	0.248

Source: Oeko-Institut (2020), Frontier Economics (2021), Fasihi and Breyer (2018)

5.2.1 CAPEX[13]

Capital costs are based on the “continuity” scenario in Oeko-Institut (2020), Table 2.7, and transformed to USD_{2021}.

Frontier Economics (2021) provides current capital costs for small and large-scale plants

- Smaller plant (100 MW_{el} electrolysis capacity): 800-1000 €/kW_{CHx}
- Larger plant (250 MW_{el} electrolysis capacity): 500-800 €/kW_{CHx}

5.2.2 OPEX

Operational costs are based on the “continuity” scenario in Oeko-Institut (2020), Table 2.7.

5.2.3 Lifetime

Plant lifetimes are based on the “continuity” scenario in Oeko-Institut (2020), Table 2.7.

5.2.4 Efficiency and conversion

The efficiency of H_2 to CH_x conversion is adopted from Frontier Economics (2021). Oeko-Institut (2020) gives a higher value of 78%. We choose to use the more conservative value. The efficiency is based on the lower heating value of hydrogen: 120 MJ/kg.

Frontier Economics (2021) denotes the **CO_2-demand** to 3,16 kgCO2/kgCHx, in which Kerosene or maritime fuel is yielded as product. Transformation based on the lower heating value of Kerosene (and similarly Diesel) of 43 MJ/kg results in 0,265 kgCO2/kWhCHx.

[12] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

[13] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

Excess water: water produced in the RWGS and Fischer-Tropsch units is derived from the energy flow and mass balance diagram in Fasihi and Breyer (2018). Water recirculation may reduce the amount of fresh water needed in the electrolysis plant.

5.2.5 Energy demand

Excess heat: the Fischer-Tropsch process is exothermic and allows for a full heat recovery for operation of an on-site DAC plant. The amount of excess heat in Table 5-2 is derived from an energy and mass flow diagram in Fasihi and Breyer (2018). As product, the jet fuel and Diesel fractions are added downstream of the hydrocracker.

Electricity demand: Electricity is required for plant operation (in full load operation) and for electrical heating of the RWGS process. Following Fasihi and Breyer (2018), 38 kWhel are needed to produce 131 kWh of jet fuel along with 312 kWh of synthetic Diesel.

5.3 Methanol synthesis

Methanol synthesis is carried out in (copper) catalysts directly from hydrogen and carbon dioxide. Schemme et al. (2020) rate the technical readiness of the process as TRL= 9.

Like for the FT e-fuels synthesis, we focus on the two-stage methanol synthesis (no co-electrolysis) for reasons of consistency and due to a lack of sufficient meta studies on direct methanol synthesis routes. Generally, the literature on the FT e-fuels synthesis also covers methanol synthesis (Section 5.2).

Data used as input into the tool is shown in Table 5-3 and described in detail in the following subsections.

Table 5-3: Techno-economic data for methanol synthesis plants

Parameter	Unit	2020	2030	2040
CAPEX[14]	USD_{2021}/kW	727	623	459
OPEX	%CAPEX p.a.	3	3	3
Lifetime	Years	30	30	30
Efficiency	kWh MeOH/kWh H_2	0.8	0.8	0.8
CO_2 demand	kg CO_2/kWh MeOH	0.264	0.264	0.264
Electricity demand	kWh_{el}/ kWh MeOH	0.040	0.040	0.040

Source: Oeko-Institut (2020), Frontier Economics (2021), Fasihi and Breyer (2018)

5.3.1 CAPEX[15]

The reviewed literature reports capital costs of methanol synthesis plants at the same level as Fischer-Tropsch plants (e.g. Frontier Economics 2021). For consistency, we choose the same

[14] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).
[15] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

source as for Fischer-Tropsch synthesis, even though costs for methanol synthesis are not explicitly mentioned in Oeko-Institut (2020).

Capital costs are based on the “continuity” scenario in Oeko-Institut (2020), Table 2.7, and transformed to USD2021.

Frontier Economics (2021) provides current capital costs for small and large-scale plant.

- Smaller plant (100 MW_{el} electrolysis capacity): 800-1000 €/kW_{MeOH}
- Larger plant (250 MW_{el} electrolysis capacity): 500-800 €/kW_{MeOH}

5.3.2 OPEX

Operational costs are based on the “continuity” scenario in Oeko-Institut (2020), Table 2.7.

5.3.3 Lifetime

Plant lifetimes are based on the “continuity” scenario in Oeko-Institut (2020), Table 2.7.

5.3.4 Efficiency

For consistency, we choose the same source for the efficiency value in the methanol synthesis as for Fischer-Tropsch synthesis, hence data is based on Frontier Economics (2021) which report an efficiency of 80%.

5.3.5 Energy demand

Electricity demand: following the energy and mass flow diagram in Fasihi and Breyer (2018), about 21 kWh electricity are needed for 95 kg of methanol, which is translated using the lower heating value of methanol to 0.040 kWh_{el}/kWh_{MeOH}.

No excess heat is provided from the methanol synthesis process. An external heat source is required, if CO_2 is to be produced on-site by a DAC facility (Fasihi and Breyer 2018).

No excess water is produced in the methanol synthesis process (Fasihi and Breyer 2018).

5.4 Ammonia synthesis (Haber-Bosch process)

Synthesising ammonia from hydrogen and nitrogen *via* the Haber-Bosch process is well established. No cost reductions are expected in the upcoming years (Frontier Economics 2021).

An air separation unit is needed to extract nitrogen from ambient air. The overall process requires electricity for the air separation unit as well as for compressors.

Main literature sources used to represent the process:

- **Fasihi et al. (2021)** give techno-economic data for ammonia synthesis units.
- **Frontier Economics (2021):** see above (Section 5.2)
- **Ikäheimo et al. (2018)** is another study from Finland that shares a co-author (Robert Weiss) with the more recent study by Fasihi et al. (2021).

Data used as input into the tool is show in Table 5-4 and described in detail in the following subsections.

Table 5-4: Techno-economic data for Haber-Bosch plants

Parameter	Unit	2020	2030	2040
CAPEX[16]	USD_{2021}/kW	719	719	719
OPEX	%CAPEX p.a.	5	5	5
Lifetime	Years	30	30	30
Efficiency	kWh NH_3/kWh H_2	0.82	0.82	0.82
N_2 demand	Kg N_2/kWh NH_3	0.160	0.160	0.160
Electricity demand	kWh_{el}/ kWh NH_3	0.142	0.142	0.142

Source: Fasihi et al. (2021), Frontier Economics (2021)

5.4.1 CAPEX[17]

Capital costs are based on Fasihi et al. (2021), Table A.1. The denominator is transformed from tons per year into kilowatts by employing the lower heating value of ammonia and full load hours as used within this analysis (8000 h/year). The costs are then transformed to USD2021 values.

Frontier Economics (2021) provides current capital costs for small and large-scale plant (8.000 h/a).

- Smaller plant (100 MW_{el} electrolysis capacity): 1000 €/t_{NH3}
- Larger plant (250 MW_{el} electrolysis capacity): 631 €/t_{NH3}

5.4.2 OPEX

Operational costs are based on Fasihi et al. (2021), Table A.1.

5.4.3 Lifetime

Plant lifetimes are based on Fasihi et al. (2021), Table A.1.

5.4.4 Efficiency and conversion

For consistency with the other transformation processes, **the efficiency of H_2 to ammonia conversion** is adopted from Frontier Economics (2021).

For the conversion of nitrogen to ammonia, no value is provided in Frontier Economics (2021). Therefore, we use Fasihi et al. (2021) as a source and transform the mass balance using the lower heating value of ammonia: 18.7 MJ/kg. Note, that in Fasihi et al. (2021), Table A1, the H_2 and N_2 demands got mixed up, which has been proofed by conducting a mass balance for the global reaction of H_2 and N_2 to NH_3 ($N_2 + 3\ H_2 \rightarrow 2\ NH_3$). Moreover, note that electricity demand for the air separation

[16] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

[17] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

unit is already included in the energy demand reported below, hence this figure is not further used in the calculations.

No excess water is produced in the process.

5.4.5 Energy demand

The electricity demand is based on Fasihi et al. (2021), Table A.1 and transformed by employing the lower heating value of ammonia: 18.7 MJ/kg.

5.5 Direct iron reduction

Data on direct iron reduction is taken from (Wuppertal Institut; Lund University; Agora Industry 2024). Data in this source is compiled to allow cost estimates for Direct reduced iron - electric arc furnace (DRI-EAF)-based crude steel production. However, in the PTX BOA the system boundaries end with the landing of green iron (DRI or Hot briquetted iron (HBI) produced with green hydrogen as the reducing agent and heat source), i.e., not including the EAF step of the process.

- **Price for DRI-grade iron ore pellets** is assumed to be 157€/t (including a markup for the higher quality requirements) in 2030 and 165 in 2040.
- **Pellet input** is cited to be 1.39t of DRI-grade pellets per ton of DRI.
- **Electricity consumption for briquetting:** 0.012 MWh/tDRI (Orre et al. 2021)

Table 5-5 summarizes input data used to represent green iron production in the PTX BOA.

Table 5-5: Techno-economic data for green direct reduced iron production

Parameter	Final unit	Final value	Further info	Initial unit	Initial value
CAPEX[18]	USD2021/kg DRI/a	0.5	Shaft furnace incl. interaction costs	EUR2021/t crude steel	505
OPEX (fix)	USD2021/kg DRI/a	0.015		fraction of CAPEX	3%
OPEX (other variable)	USD2021/kg DRI	0.216 (2030) 0.227 (2040)	DR-grade markup already included	USD/t DR grade pellets	157 (2030) 165 (2040)
Lifetime	years	15		years	15
Efficiency	kg DRI/kwh H_2 (LHV)	0.43		kg H_2 LHV/t DRI	69,2
Electricity demand	kWh (el.)/kg DRI	0.09		GJ/t DRII	0.29

Source: **(Wuppertal Institut; Lund University; Agora Industry 2024)**

[18] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

6 Full load hours for RES-E, electrolysis, derivative production and pre- and postprocessing

For the calculation of the PTX production costs, values of full load hours (FLH) are required for the following elements within the process chain:

- RES-E technologies
- Electrolysis
- Derivative production
- Pre- and postprocessing

The app optimizes the full load hours of electrolysis and derivative production. Full load hours for RES-E technologies are input to the optimization model.

7 Production profiles and full load hours of RES-E

7.1 General approach

- For PTX BOA we need representative full load hours and production profiles for each RES-E technology and country. As we assume that a production site is at a single location, we do not want to aggregate data from a larger region and instead want to use data from a single location.
- To define one representative location for full load hours and the underlying production profile we developed the following methodology:
  - Step 1: Calculate wind and PV production profiles. We use ERA5 reanalysis weather data of the year 2021 to calculate power production profiles for each ERA5 grid cell of a source region. ERA5 has a spatial resolution of ~31 km (Hersbach et al. 2020). Power generation modelling is done using the atlite framework (Hofmann et al. 2021). For PV, we use a panel model after (Huld et al. 2010) and assume a latitude optimal orientation with no tracking of the panel. For wind power production onshore and offshore, we use a power curve of the National Renewable Energy Laboratory (NREL) 5.5 MW reference wind turbine as provided by (Hofmann et al. 2021).
  - Step 1.1: Calculate combined wind and PV production profile for hybrid production. For hybrid locations, we need to get production profiles for wind and PV from a single location which is suitable for combining the two technologies. This requires combining the two production profiles in order to get a resulting hybrid profile. We do so by following the approach of Fasihy & Breyer (2020) where we remove a curtailment from the combined hybrid profile based on the capacity of an electrolyzer: $\mathrm{flh_e} = \frac{\sum_t \min(\mathrm{wind}_t * c_{wind} + \mathrm{pv}_t * c_{pv}, c_e)}{c_e}$ wind_t and pv_t are the specific generation at time t, c_wind, c_pv, and c_e are assumed capacities of wind, PV, and the electrolyzer, respectively. We assume capacities of c_wind 1/3, c_pv=2/3, and c_e=1/3. These capacity assumptions are based on the PTXAtlas (Fraunhofer IEE 2021).
  - Step 2: Aggregate the specific generation profiles of each grid cell obtained in Step 1 and for hybrid in Step 1.1 in order to get full load hours of that grid cell for each RES-E technology.
  - Step 2.1: Mask the grid cells to match the following criteria:
    - PV, wind onshore, hybrid:
      - Grid cell must be inside the source region on land
      - FLH of PV must be greater or equal 950 hours
      - FLH of Wind onshore must be greater or equal 1500 hours
    - Wind offshore:
      - Grid cell must be in the EEZ of the source region and within 80 km from land
      - FLH Wind offshore must be greater or equal 2500 hours
  - Step 3: Rank the grid cells in a source region after their full load hours values and take the grid cell with full load hours closest to a given percentile p_i. We use the following percentiles for the different technologies:
    - PV: 90
    - Wind onshore: 95

  - Wind offshore: 90
  - Hybrid PV & wind onshore: 95
- If a source region does not have any grid cells with FLH values larger than 950, 1500 and 2500 for PV, Wind onshore and Wind offshore, respectively, we use the grid cell with the maximum FLH for the respective technology.
- The resulting full load hours have been validated with historical capacity factors by IRENA (2023) and modelling results of Fraunhofer IEE (2021).
- Upon reviewing the data for some regions, we have identified the need to adjust this quartile to better align with the region's unique geographical and developmental characteristics.
- The validation has shown that in **Namibia** full load hours for onshore wind and hybrid are underestimated with our method. Therefore, we have increased the percentile to 99.
- The onshore wind full load hours calculated by our method also show large deviations to historic values for **Costa Rica, South Africa- Kwazulu Natal** and **Indonesia**. We assume this is due to the spatial resolution of the ERA5 data set which is not able to represent specific small scale high wind locations.
  - **Costa Rica**: No correction of the value has been carried out as we did not find a solution to do so in a meaningful way.
  - **Indonesia**: The geographical distribution of Indonesia shows that wind speeds and consistency can vary greatly even over short distances, influenced by topographical features and proximity to coastlines. The initial application of the 0.95 quartile tends to overestimate the FLH for wind onshore projects in Indonesia. This overestimation arises because the top 10% of data points may be derived from highly localized and atypical conditions that do not accurately represent the general feasibility of large-scale wind projects across the country, which is why we reduce our quartile to 0.30
  - **South Africa- Kwazulu Natal**: The coastline of the Umkhayande Municipality (the northern most municipality in KwaZulu-Natal), displays the highest wind potential and is almost entirely a protected area. This poses a challenge to presenting an accurate and realistic assessment of the full load hours for wind onshore projects in the KZN province. To address these challenges and provide a more accurate assessment of the full load hours for onshore wind projects in KwaZulu-Natal, we have amended our FLH calculation methodology in this instance, lowering the quartile from 0.95 to 0.30. This adjustment will better reflect the conditions and practical project sites rather than exceptional outliers.

8 Determining optimal capacities and full load hours of system components

Costs per unit of PtX product depend not only on techno-economical parameters of processes, but also on required capacities and dispatch (i.e. full load hours). The characteristics of a cost-efficient setup depends on cost parameters and RE profiles. To keep capital costs consistent with input data assumptions, optimal investments and dispatch is calculated by using an optimization model.

8.1 Methodology

The model is implemented using PyPSA[19]. It covers electricity generation, electrolysis, derivate production, as well as electricity storage (batteries) and hydrogen storage (tanks). If applicable, it also optimizes required Direct Air Capture (DAC) and Water Desalination capacities.

The optimization is performed using the HIGHS solver[20]. Key results are presented in the "Optimization" tab. The PyPSA network object, which contains the complete model information, can be exported in NetCDF format for detailed analysis.

The key result of the optimization model are the capacities of renewable power generation, electrolyzer, derivate production, electricity storage, hydrogen storage, DAC and water desalination that are required to produce 8760 MWh of final product per year. These results will be used in the calculation of overall costs.

Optimization results are pre-calculated for all combination of default settings. If input data is modified by the user, one live optimization will be run for the selected settings. The model takes 3-15 seconds to be solved. For all other results that are displayed in the cost comparison graphs and data tables, the data modifications made by the user are considered, but the full load hour assumptions are not updated.

8.2 Limitations and scope

To keep runtimes short, the annual hourly RES-E production profiles (see Section 7) are aggregated to eight characteristic weeks using the tsam package[21].

We assume that intermediate products (electricity and hydrogen) can only be stored within one week, which means that we ignore the option of seasonal storage, e.g. storing hydrogen in rock caverns.

Transportation, including preprocessing and postprocessing of transported molecules, are not part of the optimization process. Capacity factors for preprocessing and postprocessing processes (for example liquification and regasification or cracking) are part of CAPEX assumptions taken from literature.

[19] https://pypsa.org/
[20] https://highs.dev/
[21] https://github.com/FZJ-IEK3-VSA/tsam

9 Secondary inputs

Secondary inputs included in PTX BOA cost calculations are:

- Water input (*via* sea water desalination or derived from an external source)
- CO_2 input (*via* Direct Air Capture (DAC) or derived from an external source)
- Heat supply

Data basis in the PTX BOA for these three secondary inputs further described in the following.

9.1 Water sources

Water is needed to produce hydrogen *via* electrolysis. Within PTX BOA water costs can be calculated based on sea water desalination or specific water costs (for example from an existing freshwater pipeline) can be assumed.

9.1.1 Sea water desalination

Fraunhofer IEE (2021) report capital costs of 2 €/m³ per year. Using conversions factors reported in section 12 this value is converted **to 0.0024 USD2021/l per year**[22]. **OPEX are assumed to be 4%** (Fraunhofer IEE 2021). Specific energy use is reported to be 3 kWh per m³ of water[23]. This corresponds to 0.003 kWhel/kg H_2O.

9.1.2 Specific water costs (external supply)

Specific water costs are assumed to be 0.00119 US$/kg (Pastore et al. 2022).

9.2 CO_2 input

9.2.1 Direct air capture (DAC)

Demonstrator plants for DAC exist on smaller scale for example in Germany, Switzerland, Iceland, and USA. Most prominent actor is the company Climeworks, based in Switzerland. The first large-scale DAC is announced by the companies Occidental and 1PointFive to be in operation till 2024 in Texas (Siemens Energy and Occidental 2023).

Most literature on DAC refers to a review study by Fasihi et al. (2019), in which economic and technical data is gathered for the existing DAC plants. **We follow the recommendation in the study to choose techno-economic data reported from Climeworks.**

The DAC process by Climeworks uses Temperature Swing Adsorption (TSA). The solid sorbent operates on low temperature heat and can thus be fed by excess heat. Furthermore, the amine-based sorbent allows for co-production of water, which can reduce the amount of fresh water needed for electrolysis.

[22] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

[23] https://www.erneuerbareenergien.de/onshore-wind/jeder-tropfen-zaehlt-meerwasser-wird-mit-wind-und-solar-zu-trinkwasser

Data used as input into the tool is shown in Table 9-1 and described in detail in the following subsections.

Table 9-1: Techno-economic data for DAC

Parameter	Unit		2030	2040
CAPEX[24]	USD2021 per $kgCO_2$ p.a.	High	1.659	1.493
		Medium	1.038	0.892
		Low	0.416	0.292
OPEX	%CAPEX p.a.		4	4
Lifetime	years		25	30
Electricity demand	$kWh_{el}/kgCO_2$	High	0.7	0.7
		Medium	0.463	0.452
		Low	0.225	0.203
Low temperature-heat demand	$kWh_{th}/kgCO_2$	High	2.2	2.2
		Medium	1.85	1.743
		Low	1.5	1.286
Excess water	$kgH_2O/kgCO_2$		1.4	1.4

Source: Fasihi et al. (2019)

9.2.1.1 CAPEX[25]

We use the “conservative” scenario in Fasihi et al. (2019), Table 7, which still projects significant cost degressions between 2020 and 2030 but also for 2040. For the high cost case we base our number on Prognos (2020). The medium case represents the average of the two values. For both sources are transformed to from EUR2016 and EUR2019 to USD2021 using conversion factors detailed in section 12.

9.2.1.2 OPEX

We use the “conservative” scenario in Fasihi et al. (2019), Table 7.

9.2.1.3 Lifetime

We use the “conservative” scenario in Fasihi et al. (2019), Table 7

[24] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

[25] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

9.2.1.4 Conversion factors

Energy demand: For the low cost case, we use the “conservative” scenario in Fasihi et al. (2019), Table 7, for the high cost case we rely on Prognos (2020), the medium case is defined by the average of the two values.

The low temperature heat demand given in Table 9-1 represents the maximum required heat. Depending on the overall PTX-transformation process, excess heat might be used reduce the heat demand of the DAC plant. The potential of excess heat is addressed for each transformation process in the respective section. Values for the high cost case are again taken from Prognos (2020), value for the low cost case are based on Fasihi et al. (2019), the medium case is the average of the two values.

Excess water: Fasihi et al. (2019) mentions the potential of water co-production in the DAC plant and gives an amount of 0.8-2 tH_2O/tCO_2. We choose the average value of 1.4 tH_2O/tCO_2 for all years.

9.2.2 Specific CO_2 costs (external supply)

Frontier Economics (2021) assess business cases for PTX product exports from Northern African countries. As a value for external CO_2 supply from the cement industry they assume costs of 32.6€/tCO_2. Converting this value to USD2021 yields 38.6USD2021/tCO_2. This value is taken as the global default which can be adapted by the user of the PTX BOA.

9.3 Heat supply

Heat supply is not modelled internally in the PTX BOA tool. Instead, **we assume external heat supply at 0.05 USD2021/kWh heat.** This is a rough approximation. It is compatible e.g., with heat supply *via* power-to-heat and respective wholesale electricity prices.

10 Storage

Storage options are used within the production chain of hydrogen and derivatives to ensure a (more) stable input into following conversion steps. **The tool considers two storage options:**

- **Battery storage** to store electricity from the RES-e plant before it is being used in the electrolyser.
- **Hydrogen storage** to store hydrogen from the electrolyser before it is being used in the following derivative production.

10.1 Battery storage

For battery storage we used literature data for utility scale batteries. We used the following sources and took the medium of their assumptions concerning lifetime, CAPEX, OPEX and efficiency. Battery technology is Lithium-Ion.

- Cole and Karmakar (2023)
- Brandstätt et al. (2018)
- Wille-Haussmann et al. (2022)
- The Danish Energy Agency[26]

Table 10-1: Parameters for battery storage

Parameter	year	unit	value
CAPEX[27]	2030	USD2021/kW	953.71
efficiency	2030	various (output per main input)	90%
lifetime / amortization period	2030	years	20
OPEX (fix)	2030	% of capex	0.00
CAPEX	2040	USD2021/kW	770.17
efficiency	2040	various (output per main input)	90%
lifetime / amortization period	2040	years	20
OPEX (fix)	2040	% of capex	0.00

Source: Own compilation based on sources as stated in the text

10.2 Hydrogen storage

There are several options to store hydrogen:

- Hydrogen Tanks
- Storage in Pipelines
- Salt caverns
- Rock caverns

[26] https://ens.dk/sites/ens.dk/files/Analyser/technology_datasheet_for_energy_storage.xlsx
[27] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

For PTX BOA we only consider hydrogen tanks. This is because, we consider hydrogen production in off-grid settings. In these locations we do not expect to have access to large scale underground hydrogen storage options.

Parameters have been obtained from the Danish Energy Agency which provide data on various storage technologies[28].

Table 10-2: Parameters for hydrogen storage

Parameter	year	unit	value
CAPEX[29]	2030	USD2021/kW	57.91
efficiency	2030	various (output per main input)	99%
conversion factors	2030	kWh (el.)/H2-G	0,09
lifetime / amortization period	2030	years	30
OPEX (fix)	2030	% of capex	1.29
CAPEX	2040	USD2021/kW	34.88
efficiency	2040	various (output per main input)	99%
conversion factors	2040	kWh (el.)/H2-G	0,08
lifetime / amortization period	2040	years	30
OPEX (fix)	2040	% of capex	1.29

Source: own compilation based on Danish Energy Agency

[28] https://ens.dk/sites/ens.dk/files/Analyser/technology_datasheet_for_energy_storage.xlsx
[29] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

11 Transport

The PTX BOA tool lets the user choose from **two main transport options between the supply and the demand country: ship or pipeline.**

- **The shipping option** is generally available for all products with a molecular form that permits for this transport option (i.e., all products except gaseous hydrogen and methane). For shipping transport, the tool differentiates further between two options:
  - the ship is fuelled by heavy fuel oil (HFO), or
  - the ship uses the transported PTX product as fuel.
- **The pipeline option** is only available for specific products as well as distances between supply and demand country (see chapter 11.2). For the pipeline option, the tool differentiates costs between three types of pipelines:
  - New pipelines
  - Retrofitted pipelines
  - Already existing pipelines.

Table 11-1 gives an overview on the transport options available for the respective products in the PTX BOA tool.

Table 11-1: Transport options for different selectable products in the PTX BOA

	Liquid H_2	Gaseous H_2	Ammonia	Methane (LNG)	Gaseous Methane	Methanol	FT e-fuels	Green iron
Pipeline new		X			X			
Pipeline retrofitted		X						
Pipeline existing					X			
Ship HFO	X	X	X	X	X	X	X	X
Ship using transported fuel	X		X	X		X	X	

11.1 Pre- and post-processing for transportation

Hydrogen and derivatives can be transported in and re-converted back into different states of matter. To reach these states, the products need to be processed. **To process hydrogen or derivatives into states suited for transport**, this is mostly done by cooling but also compression in the case of pipeline transport. **Post-processing** often involves a re-conversion back into the state of matter before transport, e.g. by re-gasification. In the following, we describe the pre- and postprocessing steps included in the PTX BOA tool, the data assumptions and literature sources used for cost calculations.

As most technologies for pre-and post-processing are at a high technology readiness level (TRL), **we assume that values for 2030 are equal to those for 2040.** This might not be true for LOHC but there are no literature sources to differentiate between 2030 and 2040.

11.1.1 Pre- processing before long-distance transportation

The tables below provide information on the following pre-processing steps:

- **Hydrogen:** liquefaction of hydrogen; compression of hydrogen
- **Methane:** liquefaction of methane, compression of methane
- **LOHC:** hydrogenation of LOHC

Not included here are the following products as they do not need any pre-processing transformations for transport:

- **Ammonia from Haber-Bosch** is already liquid and ready to be shipped
- **Methanol** is already liquid and ready to be shipped
- **FT e-fuels** are already liquid and ready to be shipped

Table 11-2: Pre-processing for transport – Liquefaction of hydrogen

Liquefaction of hydrogen					
Normal state	Gaseous				
Transport state	Liquid				
Process	Cooling below −252.87 °C				
	Cost pathway			**Unit**	**Source**
	low	mid	high		
CAPEX[30]	900	1,400	2,000	USD2019/kW H_2	For mid: IEA (2019, annex p.7); for low and high: IEA (2015, Table 10)
OPEX		4		% of CAPEX per year	IEA (2019, annex p.7)
Variable operating and maintenance costs (VOM)	0.24	0.30	0.39	kWh_{el}/kWh H_2	DNV GL (2020)
Lifetime		30		years	IEA (2015, Table 10)

[30] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

Table 11-3: Pre-processing for transport – Compression of hydrogen

Compression of hydrogen					
Normal state	Gaseous (depending on the electrolysis process hydrogen is released at different pressure levels). For alkaline electrolysis operating pressure is 1-30, for PEM it is 30-80 bar and for SOEC it is 1 bar (IEA 2019).				
Transport state	Gaseous (pressure in H_2-pipelines is assumed to be 30-80 bar (Guidehouse 2022))				
Process	Compression				
	Cost pathway			**Unit**	**Source**
	low (10MW)	**mid (5MW)**	**high (1MW)**		
CAPEX[31]	1180*2	1550*2	2900*2	€/kWe	DNV GL (2020); value is given in units of electricity input and needs to be converted to H_2 output; we assume 0.04 kWh/kWh H_2 as conversion factor for reasons of consistency.
OPEX	4			% of CAPEX per year	DNV GL (2020)
VOM	0.01	0.02	0.04	$kWh_{el}/kWh\ H_2$	DNV GL (2020) reports different values for different levels of pressure increase. Value range between 0.01-0.04 kWh el./kWh H_2.
Lifetime	20			years	IEA (2015, Table 10)

Table 11-4: Pre-processing for transport – Liquefaction of methane

Liquefaction of methane					
Normal state	Gaseous				
Transport state	Liquid				
Process	Cooling down to between -161 and -164°C				
	Cost pathway			**Unit**	**Source**
	low	**mid**	**high**		
CAPEX[32]	604€/tCH_4*a				Hank et al. (2020) sup. Mat.; it is not entirely clear whether CAPEX refer to CH_4 as a basis, but we assume that it does so.
OPEX	2			% of CAPEX per year	Hank et al. (2020) sup. Mat.
VOM	5%	10%	15%	%NG	Pospíšil et al. (2019), figure 14
	0.05	0.11	0.16	kWh_{el}/kWh NG	Own calculation assuming that heat is supplied from power with an efficiency of 95%
Lifetime	30			years	Not reported in sources; we assume same as harbour infrastructure: 30 years, see section 11.3.4.

In addition to the information in the table above, the analysis of Pospíšil et al. (2019) shows in detail the energy demands that arises in pre- and post-processing as well as transport of methane as LNG.

[31] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

[32] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

The information provided by the authors serves as one of the main data sources for this transformation process.

Table 11-5: Pre-processing for transport – Hydrogenation of LOHC

Hydrogenation of LOHC	
Normal state	Hydrogen gaseous
Transport state	Hydrogen bound in chemical carrier (LOHC)
Process	Pressure needs to be increased to 20-70 bar and catalyst particles are need to perform hydrogenation; the process is exothermal and can generate 10 kWh_{th}/kgH_2; for reasons of simplicity we assume that pressure increase required is the same as for a hydrogen pipeline. **Therefore, parameters for the compressor are applied (see Table 11-3).**

For methane compression we assume the same data as for hydrogen compression making the rough assumption that higher energy content of methane and higher specific mass cancel each other out in terms of energy demand for compression.

11.1.2 Post- processing after long-distance transportation

Post-processing occurs after transportation and often involves a transformation of the molecule back the initial state of matter. The tables below provide information on the following post-processing transformations as they are calculated in the PTX BOA tool:

- **Hydrogen:** Regasification of hydrogen
- **Methane:** Autothermal Reactor (ATR) with Carbon Capture; regasification of methane
- **Ammonia:** Ammonia cracker
- **LOHC:** Dehydrogenation

Table 11-6: Post-processing – Regasification of hydrogen

Regasification of hydrogen					
Normal state	Gaseous				
Transport state	Liquid				
Process	Heating up to gaseous phase				
	Cost pathway			**Unit**	**Source**
	low	**mid**	**high**		
CAPEX[33]	114	273	423	EUR2019/KW H_2	DNV GL (2020)
OPEX	2.5			% of CAPEX per year	DNV GL (2020)
VOM	0.002	0.003	0.005	kWh/kWh H_2	DNV GL (2020); we assume that VOM are losses of hydrogen in the process
Lifetime	30			years	We assume the same lifetime as for a gasification terminal (see Table 11-2)

[33] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

Table 11-7: Post-processing – Autothermal Reactor (ATR) with Carbon Capture

Autothermal Reactor (ATR) with Carbon Capture			
Normal state	Not applicable		
Transport state	Not applicable		
Process	Natural gas is received and transformed into H_2 using the ATR. In contrast to the Steam Methane Reforming (SMR) process, the ATR process does not require external heat input. Without carbon capture, the process generates excess electricity, however if integrated with carbon capture additional electricity is required. Additional electricity is required for CO_2 transport and CO_2 storage for compressors and pumps.		
	Value	**Unit**	**Source and comment**
CAPEX[34]	843	Mil. USD2021	Oni et al. (2022): values are given relative to a plant capacity of 607tH_2/day. Presumably lower heating values are applied. The basis for the cost values is CAD 2020. Converting the value to USD2021 yields 776 USD2021/kW
OPEX	5	% of CAPEX per year	Oni et al. (2022): relative to total CAPEX for the entire process
Conversion factor	0.15	GJ natural gas feedstock /kg H2	Oni et al. (2022) the value can be converted to an efficiency of 80%
VOM	3.59	kwh el/kg H_2	Oni et al. (2022): the value can be converted to 0.11 kWh el/kWh H_2
Other costs	40	USD2021/tCO2 transported and stored	Own assumption; George et al. (2022) take values of 30-50EUR2021/tCO2 for CO_2 transport and storage in Norway. Assuming a capture rate of 91% and natural gas with emission factor of 0.201kgCO2/kWh results in cost of 0.01 USD2021/kWh
Lifetime	25	years	Oni et al. (2022)

Table 11-8: Post-processing – Methane regasification

Methane regasification					
Normal state	Methane (gaseous)				
Transport state	Methane (liquid)				
Process	Heating up to gaseous phase Depending on the assumptions the process can either be accomplished in a fixed on-shore terminal (Floating Storage and Regasification Unit, FSRU) with a jetty or an onshore terminal. The former units are often-time older LNG-tankers which are retrofitted for this use and are available at discounts from new-build FSRUs. In both cases the major CAPEX cost component is a tank which balances the flow into the network. Therefore, we do not take into account further CAPEX and OPEX for regasification but account for additional energy demand, only.				
	Cost pathway			**Unit**	**Source**
	low	**mid**	**high**		
VOM		2		% of NG	Pospíšil et al. (2019)

[34] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

Table 11-9: Post-processing – Ammonia cracker

Ammonia cracker					
Normal state	Gaseous (hydrogen)				
transport state	Liquid (ammonia)				
process	Ammonia cracking is an endothermic reaction requiring heat input for heating up the ammonia before cracking. The cracking reaction is enabled by catalysts like nickel or cobalt. Given high pressures and temperatures (40barg, 900°C) 99.5% of ammonia can be converted to H_2 in the cracker (NGN; Equinor 2018).				
	low	**mid**	**high**	**Unit**	**Source**
CAPEX[35]	422	411	401	USD2021/kW	NGN; Equinor (2018, Table 3.21): low value corresponds to 17 bar H_2 output high value for 80 bar H_2 output; mid is average of the two values; initial values in were reported in GBP2018/kW H_2 HHV and converted using conversion coefficients detailed in section 12.
OPEX		3		% of CAPEX per year	NGN; Equinor (2018, Table 3.24)
Efficiency	74.2%	74.7%	75.2%	kWh H_2 LHV/ kWh NH_3 LHV	NGN; Equinor (2018, Table 3.22); initial values are given in kWh NH3/kWh H2 HHV and converted using 3.54/3 as the ratio of HHV to LHV.
Conversion factor	0.014	0.077	0.139	kWhel/kWh H_2 LHV	NGN; Equinor (2018, Table 3.22); initial values are given in kWh NH3/kWh H2 HHV and converted using 3.54/3 as the ratio of HHV to LHV.
Lifetime		25		years	NGN; Equinor (2018, Table 3.24)

Table 11-10: Post-processing – Dehydrogenation of LOHC

Dehydrogenation of LOHC (DBT)					
Normal state	Hydrogen gaseous				
Transport state	Hydrogen released from chemical carrier (LOHC)				
Process	The process requires external heat input and a temperature of about 300°C; some LOHC is lost during one cycle of hydrogenation and dehydrogenation (cf. Hank et al. 2021 sup. mat.) This is already accounted for in the shipping costs of LOHC				
	Cost pathway			**Unit**	**Source**
	low	**mid**	**high**		
CAPEX[36]	136	237	337	EUR2019/kWh H_2	DNV GL (2020); medium values are calculated as average from low and high
OPEX	2.5	3.3	4	% of CAPEX per year	DNV GL (2020); medium values are calculated as average from low and high
VOM	0.33	0.41	0.45	kWh_{th}/kWh H_2	DNV GL (2020)
Lifetime		30		years	Assumed like in IEA (2019)

[35] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

[36] Capex and OPEX are documented in USD2021 if not stated otherwise. The tool however uses USD2023. Therefore we multiply the USD2021 with 1.154 (Deflator).

11.2 Pipeline

The option to choose pipeline transport in the dropdown menu does only exist

- if the supply and demand country are separated by a distance less than 6,000 km.
- for transport of methane or hydrogen (pipelines for ammonia or methanol or even other derivates are not foreseen)

In case there is an existing natural gas pipeline, the tool uses cost parameters that account

- in the case of hydrogen transport for a retrofitted natural gas pipeline or
- in the case of methane transport for cost of using the existing natural gas pipeline.

If no natural gas pipeline between supply and demand country exists, the tool calculates transport costs based on parameters for a new hydrogen or methane pipeline.

For both methane and hydrogen pipelines we have used levelized costs of transport [US$/kWh*km]. We have chosen to use the available data for transport costs directly. This seems to be well suited, as projects producing hydrogen e.g., in Morocco will most likely not invest themselves into pipeline infrastructure across Europe. Instead, their hydrogen will be mixed with other H_2 sources and they will be confronted with transportation costs per unit of hydrogen and per km.

11.2.1 Methane

For the levelized costs of transport, we have taken the values from Staiß (2022) who reports

- **~0.003 €/kWh*tkm for new methane pipelines** and
- **~0.001 €/kWh*tkm for continued use of existing pipelines**.

As we did not find any differentiation between onshore and offshore pipelines, we have chosen to increase the levelized costs for new offshore methane pipelines by 20% compared to the value for a new onshore pipeline.

The lifetime of pipelines has been set to 40 years according to Staiß (2022).

Losses of methane during transport must be differentiated between leakages of methane (such as diffusion) and use of methane for powering the compressors.

- Concerning the energetic use of methane for powering the compressors, Staiß (2022) suggest in their cost assumptions that external electricity is being used by the compressors. Therefore, the energy needed for compressing the methane along the way is part of the levelized costs.
- Concerning the leakages of methane due to diffusion during transport, we assume 1.7% of leakage for a transport distance of 3,000km according to UBA (2022, p. 4).

11.2.2 Hydrogen

Guidehouse (2022) share detailed data on transport costs which is directly used for the PTX BOA tool. We have chosen to use data for medium pipeline sizes, as a H_2-pipeline grid will not be based mainly on the largest diameters – at least not in the uptake phase of hydrogen trade. On this basis, **the following table provides information on pipeline data used in the PTX BOA tool.**

Table 11-11: Data used for hydrogen pipeline transport in the PTX BOA

Pipeline specifications		Transport costs	Unit
Medium (36 inch)	new	0.35	€/kg/1000km
Medium (36 inch)	retrofitted	0.12	€/kg/1000km
Offshore medium	new	0.60	€/kg/1000km
Offshore medium	retrofitted	0.15	€/kg/1000km

Source: Guidehouse (2022)

Losses of hydrogen during transport must be differentiated between leakages of hydrogen (such as diffusion) and use of hydrogen for powering the compressors.

- Concerning the energetic use of hydrogen for transport, Guidehouse (2022, Table 1) suggest in their cost assumptions that external electricity is being used by the compressors. Therefore, the energy needed for compressing the hydrogen along the way is part of the levelized costs.
- Concerning the leakages of hydrogen due to diffusion during transport, we assume 5.06% of leakage for a transport distance of 3,000km according to UBA (2022, p. 5).

11.3 Ship

The option to choose ship transport in the dropdown menu exists for all supply and demand country pairs as well as products included in the PTX BOA.

11.3.1 General considerations

- An **economic life-time of the ship** of 30 years is assumed; for reasons of consistency taken from Hank et al. (2020).
- For shipping a **common international WACC of 5%** is assumed.
- **Canal charges** are not included.

11.3.2 Calculation of distance specific CAPEX [€/kWh product*tkm]

The calculations for the shipping of each of the molecules are based on parametrisation of specific ships designed to carry the respective cargo. The characteristics of the ship, i.e., deadweight tonnage (DWT), max. volume capacity, and average travel speed, are based on existing typical ships or on assumptions on potential future ship design. In both cases data is taken from the literature rather than compiling own ship designs.

- **CAPEX by molecule for specific ship** is taken from Hank et al. (2020).
- **Ship carrying capacity**
  - is fixed by fuel in tons of product according to Hank et al. (2020), but can increase in the future in particular for liquid H2 based on future technological learning.
  - is converted into energy units [kWh of product] by applying the respective energy density factor; for LOHC the product refers to the transported H2, assuming a DBT carrying capacity of 6,23% in terms of tonnage.

- **Transportation potential**
  - The propulsion speed is individual by transported molecule, taken from Hank et al. (2020). Currently ship speeds are substantially lower as they have been reduced in the aftermath of the financial crisis and the covid pandemic to reoptimize fuel consumption and costs. Since then, they have not returned to initial values. This is not reflected in current assumptions.
  - The availability of the ship is fixed to 95% according to Hank et al. (2020).
- **Distance dependent specific CAPEX [€/kWh product*tkm]** are calculated by dividing CAPEX ship [€] by capacity in [kWh product] and transport potential in [tkm] and multiplied with two to account for the round trip. Due to a simplified calculation routine, CAPEX are calculated as levelized costs and fed into the corresponding parameter, even though these levelized costs do not include the variable costs. These are expressed as losses (see section 11.3.6)

11.3.3 Fixed shipping costs

- **Port and canal charges** are currently not included in the calculations.
- **OPEX**: 4% of CAPEX for shipping and for storage, according to UNSW Sydney (2021);
- **Handling costs**: Load and unload time are assumed 1.5 days each, according to UNSW Sydney (2021). Levelized costs equal to 3 days of ship utilization are added to fixed OPEX in terms of USD_{2021}/kWh product.

Note that, for LOHC, some of the carrier (e.g. DBT) cannot not be recovered during one hydration and dehydration cycle so that it needs to be replaced to keep the capacity of a transport connection constant. Values quantifying these losses in the literature diverge significantly: while Hank et al. (2020) assume a loss of 0.1 wt%, Staiß (2022) assume an carrying efficiency of 80% per round trip. We base the calculations on a replacement requirement of 1% per round trip. Replacement cost of 2€/kg are reported consistently in Staiß (2022) and Hank et al. (2020). Staiß (2022) add reprocessing costs of 0.005€/kg per round trip. **Cost of lost LOHC and LOHC reprocessing add up to 0.14 USD2021/kWh H_2.**

11.3.4 Import and Export terminal

As major CAPEX items, storage in the export and import terminals are included. Data is taken from UNSW Sydney (2021) (assuming that storage needs to be able to hold one ship load in both the import and the export terminal). Investment cost for storage for LOHC and methanol seem very high in this data source, given that it does not require specific cooling or other treatment (like ammonia). Therefore, for these two carriers values are taken from Hank et al. (2020).

Storage sizes, and therefore the CAPEX, is tied to the ship capacity and can be understood as part of the integrated transport infrastructure required for the shipment. The capacity that this system can ship on a yearly basis depends on the ship's size and speed and on the distance between export and import harbour. Hence, it can also be reported as a distance-specific CAPEX [€/kwh product*tkm] by dividing CAPEX by ship capacity [kWh product] and distance potential; and simply added to the ship CAPEX.

Storage is also associated with boil-off. However, specifying the boil-off would require complex assumptions on the operation schedule of the storage, depending on how often a ship arrived at the port and on the optimisation with final conversion steps and further transport capacities. We have decided to level this step out.

11.3.5 Levelized costs of shipping and harbour storage

To calculate levelized costs for shipping and harbour storage we proceed as follows:

- The specific CAPEX calculated for the ship transport (see section 11.3.2) and for import and export terminal storage (see section 11.3.4) are added up.
- For levelising the costs, general assumptions about the lifetime of ships (30 years) and the general assumption about WACC (5%) are used (see section 11.3.1).
- Finally, OPEX (see section 11.3.3) are added to the value obtained.

Calculations for Green iron shipping are based on current rates for bulk shipping.[37] The rate for a capsize 75,000 DWT ship for a one-year charter 15,500 USD/day.

Final values on distance-dependent specific ship and storage levelized costs and port handling costs are reported in Table 11-12.

Table 11-12: Ship transportation – distance dependent specific ship and storage levelized costs and port handling costs for round trip

Parameter	Unit	NH_3	LH_2	LOHC-H_2	LCH_4	CH_3OH	FT e-fuels	Green iron
Distance dependent specific ship and storage levelized costs for round trip	[USD2021/MWh product*tkm/a]	0.32	1.50	1.35	0.25	0.11	0.05	0.33
Costs of port handling round trip	[USD2021/MWh product]	0.42	1.96	1.35	0.33	0.11	0.05	0.65

Source: methodology as described in text

11.3.6 Variable shipping costs

Fuel consumption is calculated based on Specified maximum continuous rating (SCMR) power of the respective engine/turbine and efficiencies taken from Hank et al. (2020). Based on this information, a value for the specific own fuel consumption is calculated by dividing the primary energy demand of the ship per hour by the ship velocity and fuel carrying capacity of the ship (in terms of the shipped product, in the case of LOHC, the shipped produced is assumed to be H_2 which can be released onboard using engine waste heat). This gives a value in [kWh product/product*tkm].

The products boil-off when shipped, however the factor is very different between the products due to different cooling requirements and other product characteristics. **Boil-off rates are taken from Hank et al. (2020).** For ammonia, UNSW Sydney (2021) gives a boil-off rate with is an order of magnitude lower. In order to provide conservative assumptions, we decide to stick with the values provided in the first source. Boil-off rates are reported in the table below.

37 https://www.handybulk.com/ship-charter-rates/

Table 11-13: Ship transportation – Boil-off rates for different products

Item	Boil-off rate [fraction/d]	Source	Comments	Recalculated to [%/tkm]
NH_3	0.04%	Hank et al. (2020)	UNSW Sydney (2021) has order of magnitude lower boil-off rate for NH_3	0.05%
LH_2	0.2%	Hank et al. (2020)		0.23%
LOHC-H_2	0.0%	Hank et al. (2020)		0.00%
LCH_4	0.1%	Hank et al. (2020)	Very optimistic value, current LNG-ships have 0.2%	0.12%
CH_3OH	0.02%	UNSW Sydney (2021)		0.02%
FT e-fuels	0.0%		Liquid fuels like diesel do not boil-off	0.00%
Green iron	0.0%		Solid bulk goods like direct reduced iron not boil-off	0.00%

Source: methodology as described in text

With modern concepts in terms of the ship propulsion and efficient energy use, Hank et al. (2020) assumes that the boil-off is used as fuel input and not released into the atmosphere. This is a strong assumption both in terms of the GHG effect (in particular if methane is released) and in terms of the overall efficiency of the process chains, as 13% (methanol) to 42% (liquid hydrogen) or even 59% (methane) of the energy demand for propulsion are provided from boil-off.

To contrast this optimised case, the **PTX BOA provides the option to calculate the same value for the case that heavy fuel oil (HFO) is used as fuel,** assuming that a diesel engine is used for propulsion instead. In this case, we assume that effects of reduction in DWT for carrying the fuel and increase in supplied fuel, as it is not used during the trip, cancel each other out. Boil-off on the delivery trip, still needs to be accounted for.

For both cases we assume that the return trip required 70% of the fuel of the delivery trip and that the same fuel is used on the delivery and the return trip.

Table 11-14 reports final fuel demand for different products and fuel supply options.

Table 11-14: Ship transportation – Final fuel demand for different products and fuel supply options

Parameter	Unit	NH_3	LH_2	LOHC-H_2	LCH_4	CH_3OH	FT e-fuels	Green iron
Final fuel demand average for both passages using own fuel	**[MWh energy product/MWh product*tkm]**	0.49%	0.69%	1.15%	0.21%	0.28%	0.13%	n/a
Final fuel demand average for both passages using HFO	**[MWh HFO/MWh product*tkm]**	0.0053	0.0080	0.0099	0.0033	0.0031	0.0013	n/a

Source: methodology as described in text

Fuel demand for Green iron shipping is not reported separately but included in the levelized costs.

11.4 Transport Distances

The PTX BOA differentiates between sea and pipeline distances. For sea distances, we refer to existing data sources. For pipeline distances, we developed our own methodology, which is described in section 11.4.2.

11.4.1 Sea distance

11.4.1.1 Data sources of sea distances and use of canals

The sea distance needed for the tool is taken from different datasets:

- **The first – and main one – being calculations made by EWI** (2020, resp. EWI). They collected their data from the CERDI sea distance database by Bertoli et al. (2016, resp. CERDI). Since EWI does not cover all necessary countries for the tool, further sea distance data were retrieved from the original CERDI database, which we employed as main data source.
- **The second one being data from the HySupply shipping tool** (UNSW Sydney 2021).This tool is based on data from sea-distances.org[38] and provides sea distances in nautical miles for its relevant countries with a clear focus on Australia. The biggest difference to the EWI and CERDI database is that in the HySupply shipping tool, information on start and end ports is provided in detail. As a result, the HySupply data frequently diverge from the EWI and CERDI data and can be assumed to be the more accurate source data. Yet not all PTX BOA countries are covered in this data.

[38] https://sea-distances.org/

If available, we used data from the HySupply shipping tool (UNSW Sydney 2021) as – due to its methodology – it can be assumed to be more accurate on sea distances. **Information is provided on the following country combinations:**

- **Supply countries:** Algeria, Australia, Chile, Saudi Arabia, South Africa, UAE, USA
- **Demand countries:** China, France, Japan, Netherlands, South Korea, Spain.

For all other country pairs, we referred to the CERDI database a main source (Bertoli et al. 2016). Hence, a large part of country pair sea distances in the PTX BOA is significantly influenced by the method used therein:

- **The identification of relevant ports:** First, each country was divided in grid cells of 100 m³ to identify the coastal cells. Further, they relied on Halpern et al. (2008) to select the possible most frequently used shipping line from one county coastal cell to another. The shipping lines are combined with FAO data[39] on major land roads, to make sure that the relevant port coastal cell is not located in an unpopulated area. Since some countries have access both to the Pacific and Atlantic Ocean, two relevant ports were selected, if it was considered useful by the authors. For landlocked countries like Kazakhstan, relevant foreign ports with minimal road distance to its capital were selected but also the direct maritime distances between its domestic port on the Caspian Sea was computed.
- **The computation of the sea distance:** The distance between the relevant ports is the shortest path relying on Halpern et al. (2008) (using Mollweide projection). For each port, a raster distance map is created using Spatial Analyst Coast Distance to connect a countries home port and other relevant ports, following the Halpern et al. (2008) shipping routes. In case of pairs of landlocked countries, the road distance between their capitals can be shorter than the sum of the road distances between capital and relevant ports. Accordingly, they assumed that merchandise is unlikely to go by ship.

There are pitfalls of the methodology employed by CERDI which we addressed as follows:

- The relevant ports selected by the grid analysis for countries relevant to us do not match the real conditions in various cases (especially the demand countries Germany, Netherlands, Spain, France, United States and the respective supply countries like Denmark, Norway, Spain, India, Jordan, Mexico, Peru, Russia, Saudi Arabia, South Africa, Portugal, Thailand, and Kazakhstan). The resulting distances between the respective pairs seemed off (either the distance was too long or too short).
- After further research on the used relevant ports in the CERDI dataset, we decided to re-do the shipping distance between the conspicuous pairs with sea-distances.org[40]. Here, it is possible to compare the countries or more precisely specific ports. We identified the relevant ports *via* quick research and based on the possible shortest route (e.g., routes from Norway to Spain head to Bilbao instead of Barcelona).
- In some cases, the difference between the sea-distances.org data and CERDI dataset were quite significant (> 500-1,000 km). In this case we opted for data from sea-distances.org.
- The landlocked country Kazakhstan posed the challenge that it was not possible to re-do the distances with sea-distance.org since there is no seaport. Due to the lack of alternative, we accepted the CERDI data.

[39] GeoNetwork database by FAO (http://www.fao.org/geonetwork/srv/en/)
[40] https://sea-distances.org/

Information on the use of either the Panama Canal or Suez Canal in transportation between supply and demand countries:

- For all combinations, the optically shortest transport routes were compared *via* Google Maps. Since this visual matching was not always clear, once again sea-distances.org was used for uncertain routes, since it is possible to combine different ports, we identified again *via* quick research.
- The results show the shortest to longest transport route in nautical miles and always indicated whether a canal is used. The nautical miles were converted to km (multiply by factor 1,852) and then compared with the existing sea distance transport kilometers to confirm the route used in the CERDI dataset.

Final data on sea distances used in the PTX BOA are provided in a separate data set that will be published soon. For transparency, data on transport distances that are being used for your specific setting in the PTX BOA can be obtained from the tool itself.

11.4.1.2 Assumptions for cost calculation in the PTX BOA based on sea distances

Using the compiled data on sea distances, the tool calculates specific costs depending on the transported molecule, type of fuel used for the ship and the respective distance between origin and destination. **The following table details the relevant distances for the different cost components and reports on how the calculations are implemented in the tool.**

Table 11-15: Distances for items used in the PTX BOA and current implementation

Cost components	Relevant distances	Implementation
CAPEX ship and CAPEX import and export terminal (storage)	2*trip distance between import and export terminal + 2* load/unload time	• CAPEX for ship and harbour storage are calculated as round trip (multiplied with 2) • Extra costs for load/unload times are only included as fix extra costs, not depending on the number of possible round trips
Final fuel demand (own product or HFO)	2*trip distance between import and export terminal	• Energy demands are multiplied with 1.7 to account for the round trip but also for less energy required of an unloaded ship • Energy demand in the port is not included assuming external energy supply and the bulk of the energy necessary for propulsion.
Boil-off	1*trip distance trip distance between import and export terminal	Included as stated (see 11.3.6)
Canal and port charges	2 times	Not included in current version

11.4.2 Pipeline distance and sea share

In the tool, we distinguish between **existing pipelines** and **potential pipeline connections**. The distance of both types of pipeline connections is calculated in [km]. All pipeline distances are rounded to 500 km, distances smaller than 250 km are rounded up to 250 km. This is due to limited data availability on existing connections and to the large uncertainties regarding potential pipelines. The pipeline distances used in the tool are thus approximate distance classes rather than exact pipeline distances.

11.4.2.1 Existing pipeline connections

Data on distances of existing pipeline connections were obtained from the Global Gas Infrastructure Tracker (GGIT) (Global Energy Monitor 2023). In this data base, we only considered pipelines with the status "operating" as existing pipeline connections.

The tool considers the pipeline connections as they are built. Hence, existing pipeline connections do not have a uniform connection principle (such as potential pipeline distances; see below). All possible connection types are included such as center-to-coast/border (e.g., DZA-ESP), coast/border-to-coast/border (e.g., NOR-DEU) or coast/border-to-center (e.g., PRT-ESP).

Final data used in the PTX BOA tool on existing pipeline connections are shown in Table 11-16.

Table 11-16: Distances and sea share of existing pipeline connections between PTX BOA supply and demand countries

PTX BOA demand country connection	PTX BOA supply country connection	Approx. distance [km]	Approx. sea share [%]
Spain	Algeria	1,000	28
	Morocco	250	18
	Portugal	250	0
France	Spain	100	0
Germany	Denmark	500	0
	Norway	500	100
	Russia	1,000	100
China	Kazakhstan	1,500	0
	Russia	4,000	0
USA	Mexico	500	100

Source: Global Energy Monitor (2023) (distances are rounded to distance classes, see description in methodology)
Note that data from the Global Gas Infrastructure Tracker may not adequately reflect current changes in the pipeline connections.

11.4.2.2 Potential pipeline connections

Potential pipeline connections do not exist yet nor do they have to be explicitly in planning. In the tool they are defined as pipelines that could be possibly constructed between supply and demand country.

The exclusion criterion for potential pipelines is the distance between the supply and demand country: if the latter is less than 6,000 km, we assume that a pipeline connection is conceivable. Another criterion is the topography of the connection route, whether it is mainly onshore or offshore across large water bodies like oceans. The latter case is both technically more demanding and costly and therefore less likely, especially if combined with large distance > 3,000 km. Not included in the assessment of potential pipeline connections are geopolitical dimensions.

The distance of a potential pipeline connection is calculated based on data from luftlinie.org[41]. The calculation follows the guidelines below:

- **Potential onshore pipelines:** the pipeline distance is calculated from the driving distance [*Fahrtstrecke*] given by luftlinie.org between the start and end point of the connection minus 10%. The 10% is deducted to adjust the driving distance information to the distance of a potential pipeline route (further explication on this point below).
- **Potential offshore pipelines**: the pipeline distance corresponds to the airline distance between starting and end point as indicated by luftlinie.org.
- **Potential hybrid pipelines (route *via* land and sea):** the pipeline distance is calculated from the driving distance [*Fahrtstrecke*] given by luftlinie.org between the start and end point of the connection plus 10%. The 10% is added to adjust the driving distance information to the distance of a potential pipeline route (further explication on this point below).

The calculation guidelines are derived from values of existing pipeline connections: we compared the real data for existing pipeline distances with the route information obtained when entering the pipeline start and start points on map portals such as luftlinie.org or Google Maps. The results indicated deviations between the two data sources on pipeline distances. Based on this approach, the guidelines for each type of pipeline connection were deduced for the tool.

The course of a potential pipeline route follows the same assumptions for all connections. The basic principle is a center-to-coast/border connection:

- **The starting point of a potential pipeline connection** is defined at a centrally located site in the supply country. This assumption was made
  - because the RE best-site locations for hydrogen production depends on the employed technology (mainly wind and solar) and thus can be dispersed in geographically diverse locations within a country;
  - because in many countries it is not yet clear where exactly hydrogen hubs will develop. If information already exists on where hydrogen hubs are envisaged (e.g., in Chile, India), this was taken into account when choosing the location of the pipeline starting point.
- **For the end point of the pipeline connection**, we chose existing landing points at the border and/or coast of the demand country, like for example ports, LNG terminals or existing pipeline border crossings. Within each demand country, we defined a selection of potential landing points in different directions (see table below). This selection is particularly important for geographically large import countries – here only one central landing point cannot meaningfully serve all pipeline connections.

[41] https://www.luftlinie.org/

The end point of a potential pipeline therefore depends on the location of the supply country in relation to the demand country (and *vice versa*): for each connection, we chose the geographically closest landing point out of the predefined pool as the end point of the potential pipeline.

Assumptions on starting and end points of potential pipeline connections to PTX BOA demand countries are resumed in the table below.

Table 11-17: Potential landing points used to derive pipeline distances in the PTX BOA

PTX BOA demand country	Potential pipeline landing point*	Orientation
Netherlands	Rotterdam	All
Spain	Almería	South
	Barcelona	North, East
France	Marseille	South, West
	Dunkerque	North, East
Germany	Hamburg	North, West
	Au am Rhein	South
	Dresden	East, Center
Japan	Ishikari	North
	Kitakyushu	South, West
South Korea	Seoul (Icheon port)	All
China	Fangchenggang	South, East
	Nongdau	South, Center
	Point along West-East pipeline	West
India	Haldia	North, East
	Dahej	West
	Pathankot	North, West
	Kochi	South
USA	Brownsville	South

Source: own data compilation; see methodology described in text
*To be highlighted that this table only comprises potential landing points which were considered relevant for country connections included in the PTX BOA. The locations of these points are assumptions and can also develop in other places, depending on the required supply structure.

Wherever applicable, we aligned potential pipeline routes with existing and/or planned pipeline connections. Information on this was taken from the Global Gas Infrastructure Tracker (Global Energy Monitor 2023)

11.4.2.3 Sea share

The sea share is indicated in [%]. It is calculated by dividing the pipeline distance *via* sea route [in km] by the total pipeline distance (*via* land and sea route) [in km]. Alike the total pipeline distance, the pipeline distance *via* sea route is an approximation rather than an exact distance; it is rounded to 100km.

In the tool, the sea share is calculated as follows:

- **Onshore pipelines:** for (potential) pipelines running onshore only, the sea share is 0%.
- **Offshore pipelines:** for (potential) pipelines running offshore only, the sea share is 100%.
- **Hybrid pipelines:** for (potential) pipelines running onshore and offshore, the sea share varies depending on the connection route. In the tool, the sea share corresponds to the airline distance of the offshore pipeline section as indicated on luftlinie.org. To determine this section accurately, we approximate coordinates for the start and end point of the offshore section and extract the airline distance data of just this part.

Final data points that are used in the PTX BOA on potential pipeline distances and sea share thereof are shown in the table below.

Table 11-18: Distances and sea share of potential pipeline connections between PTX BOA supply and demand countries

	NLD		ESP		FRA		DEU		JPN		KOR		CHN		IND		USA	
PTX BOA supply country	Potential pipeline distance [km]	Sea share [%]	Potential pipeline distance [km]	Sea share [%]	Potential pipeline distance [km]	Sea share [%]	Potential pipeline distance [km]	Sea share [%]	Potential pipeline distance [km]	Sea share [%]	Potential pipeline distance [km]	Sea share [%]	Potential pipeline distance [km] N	Sea share [%]	Potential pipeline distance [km]	Sea share [%]	Potential pipeline distance km]	Sea share [%]
ARE	6000	0%	6000	0%	6000	0%	5500	0%	-	-	-	-	4500	11%	2000	65%	-	-
ARG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BRA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CHL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CHN	-	-	-	-	-	-	-	-	3500	29%	2000	40%	-	-	3500	0%	-	-
COL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4500	64%
CRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3500	14%
DNK	500	100%	2000	0%	1000	50%	-*	-*	-	-	-	-	-	-	-	-	-	-
DZA	3000	13%	-*	-*	2000	15%	3000	10%	-	-	-	-	-	-	-	-	-	-
EGY	5000	0%	4500	16%	4000	18%	5000	0%	-	-	-	-	-	-	5000	52%	-	-
ESP	1500	0%	-	-	-*	-*	1500	0%	-	-	-	-	-	-	-	-	-	-
IND	-	-	-	-	-	-	-	-	-	-	-	-	3000	0%	-	-	-	-
IDN	-	-	-	-	-	-	-	-	5500	91%	5500	91%	4000	50%	5000	40%	-	-
JOR	4000	0%	4000	0%	4000	0%	3500	0%	-	-	-	-	-	-	4500	0%	-	-
KAZ	4000	0%	5000	0%	4000	0%	3500	0%	-	-	-	-	-*	-*	3000	0%	-	-
KEN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5000	86%	-	-

MRT	5000	0%	3000	0%	4000	0%	5000	0%	-	-	-	-	-	-	-	-	-	-
MEX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-*	-*
MAR	2500	0%	-*	-*	2000	0%	2500	0%	-	-	-	-	-	-	-	-	-	-
NAM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NOR	1000	100%	2000	45%	1000	90%	-*	-*	-	-	-	-	-	-	-	-	-	-
PER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5500	58%
PRT	2000	0%	-*	-*	1000	0%	2000	0%	-	-	-	-	-	-	-	-	-	-
RUS	4000	0%	5000	0%	4000	0%	-*	-*	4000	18%	3000	0%	-*	-*	4000	0%	-	-
SAU	5000	0%	5000	0%	5000	0%	4500	0%	-	-	-	-	-	-	3500	74%	-	-
SWE	2000	15%	3000	10%	2000	15%	1000	30%	-	-	-	-	-	-	-	-	-	-
THA	-	-	-	-	-	-	-	-	5000	18%	5000	16%	1500	0%	2500	0%	-	-
TUN	2500	28%	1500	47%	1000	70%	2000	35%	-	-	-	-	-	-	-	-	-	-
UKR	2000	0%	3000	0%	2000	0%	1500	0%	-	-	-	-	-	-	-	-	-	-
URY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
USA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VNM	-	-	-	-	-	-	-	-	4000	23%	5000	16%	1000	0%	3500	0%	-	-
ZAF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Source: see methodology described in text
*Fields marked with (*) are left empty since there is already an existing pipeline connection for these country pairs (see Table 11-16)

12 Further assumptions

12.1 WACC

For the calculation of the PTX production costs in the PTX BOA supply countries, values of country-specific ***Weighted average cost of capital*** **(WACC)** are required. As a simplification of WACC, we use *Equity Risk Premiums* per country based on[42] . We used the value for 2023 for each country[43].

The detailed data for WACC used in the tool for every country is shown in Annex II: Data per country for WACC. Mauretania and Algeria have not been reported on in Damodaran, we therefore used the average of all reported African countries which is 14.6%.

12.2 Bunker fuels

The PTX BOA includes the transport option of using bunker fuels as ship fuel (i.e. alternatively to using transported product as ship fuel). **As main data source for cost assumptions for bunker fuels we use IEA** (2020). Based on this, we calculate specific cost assumptions for the three different cost reduction pathways offered as options in the PTX BOA (see table below).

Table 12-1: Assumptions on bunker fuels costs

Bunker fuel	Unit	Low	Medium	High
Initial value	USD/GJ fuel	5	8.5	12
Final value	USD2021/MWh fuel	1.64	2.80	3.94

Source: Own calculations based on IEA (2020)

12.3 Deflators and currency conversion

Data sources differ in the base year for the cost data and the underlying currency. In order to bring cost values to a common basis, **we use the inflator values shown in Table 12-2 and the currency conversion factors shown in Table 12-3.**

Table 12-2: Inflator to base year 2021

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Value	1.35	1.33	1.31	1.30	1.28	1.28	1.27	1.25	1.24	1.22	1.21	1.20	1.18	1.16
Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**				
Value	1.13	1.11	1.10	1.08	1.06	1.04	1.02	1.00	0.92	0.87				

Source: Own table

42 https://pages.stern.nyu.edu/~adamodar/pc/archives/ctryprem22.xlsx

43 The raw data can be obtained from https://pages.stern.nyu.edu/~adamodar/. The most recent data can be found in an excel here https://www.stern.nyu.edu/~adamodar/pc/datasets/ctryprem.xlsx. Data for previous years can be found in the archive.

Table 12-3: Currency conversion factors

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
USD/ EUR	0.92	0.90	0.95	1.13	1.24	1.25	1.26	1.37	1.47	1.39	1.33	1.39	1.29	1.33
Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**				
USD/ EUR	1.33	1.11	1.11	1.13	1.18	1.12	1.14	1.18	1.08	1.09				
Year	**2018**													
EUR/ GBP	1.15													

Source: Own table

12.4 Conversion factors and calorific values

For calculations in the PTX BOA, **we use the following conversion factors and calorific values:**

Table 12-4: Conversion factors and calorific values used in the PTX BOA tool

	Final unit	Final value	Further information	Initial unit	Initial value
Methanol (liquid)	kWh CH_3OH/kg	5.53		MJ/kg LHV	19.9
Methane (gas)	kWh CH_4/kg	13.50		MJ/kg LHV	48.6
Methane (liquid)	kWh CH_4/kg	13.50		MJ/kg LHV	48.6
FT e-fuels	kwh CH_x/kg	11.94		MJ/kg LHV	43
Green iron	kg DRI/kg	1.00	No conversion necessary		
Hydrogen (gas)	kWh H_2/kg	33.33		kWh/kg LHV	33.33
Hydrogen (liquid)	kWh H_2/kg	33.33		kWh/kg LHV	33.33
Hydrogen (LOHC)	kWh H_2/kg	33.33	Also refers to mass of H_2 not to mass of LOHC	kWh/kg LHV	33.33
Ammonia (liquid)	kWh NH_3/kg	5.20		MJ/kg LHV	18.72

Source: Own table based on https://webbook.nist.gov/cgi/inchi/InChI%3D1S/H2/h1H; https://echa.europa.eu/de/brief-profile/-/briefprofile/100.044.216

13 Annex I: CAPEX Data for RES-E per country

PV tilted	DZA	2030	LOW	USD2021/kW	463.87
PV tilted	ARG	2030	LOW	USD2021/kW	523.91
PV tilted	AUS	2030	LOW	USD2021/kW	515.60
PV tilted	BRA	2030	LOW	USD2021/kW	416.36
PV tilted	CHL	2030	LOW	USD2021/kW	414.45
PV tilted	CHN	2030	LOW	USD2021/kW	361.29
PV tilted	COL	2030	LOW	USD2021/kW	463.87
PV tilted	CRI	2030	LOW	USD2021/kW	463.87
PV tilted	DNK	2030	LOW	USD2021/kW	632.87
PV tilted	EGY	2030	LOW	USD2021/kW	463.87
PV tilted	IND	2030	LOW	USD2021/kW	313.91
PV tilted	IDN	2030	LOW	USD2021/kW	522.24
PV tilted	JOR	2030	LOW	USD2021/kW	463.87
PV tilted	KAZ	2030	LOW	USD2021/kW	463.87
PV tilted	KEN	2030	LOW	USD2021/kW	463.87
PV tilted	MRT	2030	LOW	USD2021/kW	463.87
PV tilted	MEX	2030	LOW	USD2021/kW	500.77
PV tilted	MAR	2030	LOW	USD2021/kW	463.87
PV tilted	NAM	2030	LOW	USD2021/kW	463.87
PV tilted	NOR	2030	LOW	USD2021/kW	518.99
PV tilted	PER	2030	LOW	USD2021/kW	463.87
PV tilted	PRT	2030	LOW	USD2021/kW	548.89
PV tilted	RUS	2030	LOW	USD2021/kW	945.49
PV tilted	SAU	2030	LOW	USD2021/kW	348.49
PV tilted	ZAF	2030	LOW	USD2021/kW	618.54
PV tilted	ESP	2030	LOW	USD2021/kW	424.29
PV tilted	SWE	2030	LOW	USD2021/kW	518.99
PV tilted	THA	2030	LOW	USD2021/kW	418.08
PV tilted	TUN	2030	LOW	USD2021/kW	463.87
PV tilted	ARE	2030	LOW	USD2021/kW	348.49
PV tilted	UKR	2030	LOW	USD2021/kW	518.99
PV tilted	URY	2030	LOW	USD2021/kW	463.87
PV tilted	USA	2030	LOW	USD2021/kW	608.69
PV tilted	VNM	2030	LOW	USD2021/kW	418.08
PV tilted	DZA	2040	LOW	USD2021/kW	301.03
PV tilted	ARG	2040	LOW	USD2021/kW	339.99
PV tilted	AUS	2040	LOW	USD2021/kW	334.60
PV tilted	BRA	2040	LOW	USD2021/kW	270.19
PV tilted	CHL	2040	LOW	USD2021/kW	268.96
PV tilted	CHN	2040	LOW	USD2021/kW	234.46
PV tilted	COL	2040	LOW	USD2021/kW	301.03
PV tilted	CRI	2040	LOW	USD2021/kW	301.03

PV tilted	DNK	2040	LOW	USD2021/kW	410.70
PV tilted	EGY	2040	LOW	USD2021/kW	301.03
PV tilted	IND	2040	LOW	USD2021/kW	203.71
PV tilted	IDN	2040	LOW	USD2021/kW	338.91
PV tilted	JOR	2040	LOW	USD2021/kW	301.03
PV tilted	KAZ	2040	LOW	USD2021/kW	301.03
PV tilted	KEN	2040	LOW	USD2021/kW	301.03
PV tilted	MRT	2040	LOW	USD2021/kW	301.03
PV tilted	MEX	2040	LOW	USD2021/kW	324.97
PV tilted	MAR	2040	LOW	USD2021/kW	301.03
PV tilted	NAM	2040	LOW	USD2021/kW	301.03
PV tilted	NOR	2040	LOW	USD2021/kW	336.80
PV tilted	PER	2040	LOW	USD2021/kW	301.03
PV tilted	PRT	2040	LOW	USD2021/kW	356.20
PV tilted	RUS	2040	LOW	USD2021/kW	613.57
PV tilted	SAU	2040	LOW	USD2021/kW	226.15
PV tilted	ZAF	2040	LOW	USD2021/kW	401.40
PV tilted	ESP	2040	LOW	USD2021/kW	275.34
PV tilted	SWE	2040	LOW	USD2021/kW	336.80
PV tilted	THA	2040	LOW	USD2021/kW	271.31
PV tilted	TUN	2040	LOW	USD2021/kW	301.03
PV tilted	ARE	2040	LOW	USD2021/kW	226.15
PV tilted	UKR	2040	LOW	USD2021/kW	336.80
PV tilted	URY	2040	LOW	USD2021/kW	301.03
PV tilted	USA	2040	LOW	USD2021/kW	395.01
PV tilted	VNM	2040	LOW	USD2021/kW	271.31
PV tilted	DZA	2030	MEDIUM	USD2021/kW	525.09
PV tilted	ARG	2030	MEDIUM	USD2021/kW	593.05
PV tilted	AUS	2030	MEDIUM	USD2021/kW	583.65
PV tilted	BRA	2030	MEDIUM	USD2021/kW	471.30
PV tilted	CHL	2030	MEDIUM	USD2021/kW	469.15
PV tilted	CHN	2030	MEDIUM	USD2021/kW	408.97
PV tilted	COL	2030	MEDIUM	USD2021/kW	525.09
PV tilted	CRI	2030	MEDIUM	USD2021/kW	525.09
PV tilted	DNK	2030	MEDIUM	USD2021/kW	716.39
PV tilted	EGY	2030	MEDIUM	USD2021/kW	525.09
PV tilted	IND	2030	MEDIUM	USD2021/kW	355.34
PV tilted	IDN	2030	MEDIUM	USD2021/kW	591.17
PV tilted	JOR	2030	MEDIUM	USD2021/kW	525.09
PV tilted	KAZ	2030	MEDIUM	USD2021/kW	525.09
PV tilted	KEN	2030	MEDIUM	USD2021/kW	525.09
PV tilted	MRT	2030	MEDIUM	USD2021/kW	525.09
PV tilted	MEX	2030	MEDIUM	USD2021/kW	566.86
PV tilted	MAR	2030	MEDIUM	USD2021/kW	525.09
PV tilted	NAM	2030	MEDIUM	USD2021/kW	525.09

PV tilted	NOR	2030	MEDIUM	USD2021/kW	587.48
PV tilted	PER	2030	MEDIUM	USD2021/kW	525.09
PV tilted	PRT	2030	MEDIUM	USD2021/kW	621.33
PV tilted	RUS	2030	MEDIUM	USD2021/kW	1.070.27
PV tilted	SAU	2030	MEDIUM	USD2021/kW	394.48
PV tilted	ZAF	2030	MEDIUM	USD2021/kW	700.17
PV tilted	ESP	2030	MEDIUM	USD2021/kW	480.29
PV tilted	SWE	2030	MEDIUM	USD2021/kW	587.48
PV tilted	THA	2030	MEDIUM	USD2021/kW	473.26
PV tilted	TUN	2030	MEDIUM	USD2021/kW	525.09
PV tilted	ARE	2030	MEDIUM	USD2021/kW	394.48
PV tilted	UKR	2030	MEDIUM	USD2021/kW	587.48
PV tilted	URY	2030	MEDIUM	USD2021/kW	525.09
PV tilted	USA	2030	MEDIUM	USD2021/kW	689.02
PV tilted	VNM	2030	MEDIUM	USD2021/kW	473.26
PV tilted	DZA	2040	MEDIUM	USD2021/kW	386.13
PV tilted	ARG	2040	MEDIUM	USD2021/kW	436.11
PV tilted	AUS	2040	MEDIUM	USD2021/kW	429.19
PV tilted	BRA	2040	MEDIUM	USD2021/kW	346.58
PV tilted	CHL	2040	MEDIUM	USD2021/kW	344.99
PV tilted	CHN	2040	MEDIUM	USD2021/kW	300.74
PV tilted	COL	2040	MEDIUM	USD2021/kW	386.13
PV tilted	CRI	2040	MEDIUM	USD2021/kW	386.13
PV tilted	DNK	2040	MEDIUM	USD2021/kW	526.81
PV tilted	EGY	2040	MEDIUM	USD2021/kW	386.13
PV tilted	IND	2040	MEDIUM	USD2021/kW	261.31
PV tilted	IDN	2040	MEDIUM	USD2021/kW	434.72
PV tilted	JOR	2040	MEDIUM	USD2021/kW	386.13
PV tilted	KAZ	2040	MEDIUM	USD2021/kW	386.13
PV tilted	KEN	2040	MEDIUM	USD2021/kW	386.13
PV tilted	MRT	2040	MEDIUM	USD2021/kW	386.13
PV tilted	MEX	2040	MEDIUM	USD2021/kW	416.85
PV tilted	MAR	2040	MEDIUM	USD2021/kW	386.13
PV tilted	NAM	2040	MEDIUM	USD2021/kW	386.13
PV tilted	NOR	2040	MEDIUM	USD2021/kW	432.01
PV tilted	PER	2040	MEDIUM	USD2021/kW	386.13
PV tilted	PRT	2040	MEDIUM	USD2021/kW	456.90
PV tilted	RUS	2040	MEDIUM	USD2021/kW	787.04
PV tilted	SAU	2040	MEDIUM	USD2021/kW	290.09
PV tilted	ZAF	2040	MEDIUM	USD2021/kW	514.88
PV tilted	ESP	2040	MEDIUM	USD2021/kW	353.19
PV tilted	SWE	2040	MEDIUM	USD2021/kW	432.01
PV tilted	THA	2040	MEDIUM	USD2021/kW	348.02
PV tilted	TUN	2040	MEDIUM	USD2021/kW	386.13
PV tilted	ARE	2040	MEDIUM	USD2021/kW	290.09

PV tilted	UKR	2040	MEDIUM	USD2021/kW	432.01
PV tilted	URY	2040	MEDIUM	USD2021/kW	386.13
PV tilted	USA	2040	MEDIUM	USD2021/kW	506.68
PV tilted	VNM	2040	MEDIUM	USD2021/kW	348.02
PV tilted	DZA	2030	HIGH	USD2021/kW	609.80
PV tilted	ARG	2030	HIGH	USD2021/kW	688.72
PV tilted	AUS	2030	HIGH	USD2021/kW	677.80
PV tilted	BRA	2030	HIGH	USD2021/kW	547.34
PV tilted	CHL	2030	HIGH	USD2021/kW	544.83
PV tilted	CHN	2030	HIGH	USD2021/kW	474.95
PV tilted	COL	2030	HIGH	USD2021/kW	609.80
PV tilted	CRI	2030	HIGH	USD2021/kW	609.80
PV tilted	DNK	2030	HIGH	USD2021/kW	831.96
PV tilted	EGY	2030	HIGH	USD2021/kW	609.80
PV tilted	IND	2030	HIGH	USD2021/kW	412.67
PV tilted	IDN	2030	HIGH	USD2021/kW	686.54
PV tilted	JOR	2030	HIGH	USD2021/kW	609.80
PV tilted	KAZ	2030	HIGH	USD2021/kW	609.80
PV tilted	KEN	2030	HIGH	USD2021/kW	609.80
PV tilted	MRT	2030	HIGH	USD2021/kW	609.80
PV tilted	MEX	2030	HIGH	USD2021/kW	658.31
PV tilted	MAR	2030	HIGH	USD2021/kW	609.80
PV tilted	NAM	2030	HIGH	USD2021/kW	609.80
PV tilted	NOR	2030	HIGH	USD2021/kW	682.25
PV tilted	PER	2030	HIGH	USD2021/kW	609.80
PV tilted	PRT	2030	HIGH	USD2021/kW	721.56
PV tilted	RUS	2030	HIGH	USD2021/kW	1.242.93
PV tilted	SAU	2030	HIGH	USD2021/kW	458.12
PV tilted	ZAF	2030	HIGH	USD2021/kW	813.12
PV tilted	ESP	2030	HIGH	USD2021/kW	557.77
PV tilted	SWE	2030	HIGH	USD2021/kW	682.25
PV tilted	THA	2030	HIGH	USD2021/kW	549.60
PV tilted	TUN	2030	HIGH	USD2021/kW	609.80
PV tilted	ARE	2030	HIGH	USD2021/kW	458.12
PV tilted	UKR	2030	HIGH	USD2021/kW	682.25
PV tilted	URY	2030	HIGH	USD2021/kW	609.80
PV tilted	USA	2030	HIGH	USD2021/kW	800.18
PV tilted	VNM	2030	HIGH	USD2021/kW	549.60
PV tilted	DZA	2040	HIGH	USD2021/kW	511.06
PV tilted	ARG	2040	HIGH	USD2021/kW	577.20
PV tilted	AUS	2040	HIGH	USD2021/kW	568.05
PV tilted	BRA	2040	HIGH	USD2021/kW	458.71
PV tilted	CHL	2040	HIGH	USD2021/kW	456.61
PV tilted	CHN	2040	HIGH	USD2021/kW	398.04
PV tilted	COL	2040	HIGH	USD2021/kW	511.06

PV tilted	CRI	2040	HIGH	USD2021/kW	511.06
PV tilted	DNK	2040	HIGH	USD2021/kW	697.25
PV tilted	EGY	2040	HIGH	USD2021/kW	511.06
PV tilted	IND	2040	HIGH	USD2021/kW	345.85
PV tilted	IDN	2040	HIGH	USD2021/kW	575.37
PV tilted	JOR	2040	HIGH	USD2021/kW	511.06
PV tilted	KAZ	2040	HIGH	USD2021/kW	511.06
PV tilted	KEN	2040	HIGH	USD2021/kW	511.06
PV tilted	MRT	2040	HIGH	USD2021/kW	511.06
PV tilted	MEX	2040	HIGH	USD2021/kW	551.72
PV tilted	MAR	2040	HIGH	USD2021/kW	511.06
PV tilted	NAM	2040	HIGH	USD2021/kW	511.06
PV tilted	NOR	2040	HIGH	USD2021/kW	571.78
PV tilted	PER	2040	HIGH	USD2021/kW	511.06
PV tilted	PRT	2040	HIGH	USD2021/kW	604.72
PV tilted	RUS	2040	HIGH	USD2021/kW	1.041.68
PV tilted	SAU	2040	HIGH	USD2021/kW	383.94
PV tilted	ZAF	2040	HIGH	USD2021/kW	681.46
PV tilted	ESP	2040	HIGH	USD2021/kW	467.46
PV tilted	SWE	2040	HIGH	USD2021/kW	571.78
PV tilted	THA	2040	HIGH	USD2021/kW	460.61
PV tilted	TUN	2040	HIGH	USD2021/kW	511.06
PV tilted	ARE	2040	HIGH	USD2021/kW	383.94
PV tilted	UKR	2040	HIGH	USD2021/kW	571.78
PV tilted	URY	2040	HIGH	USD2021/kW	511.06
PV tilted	USA	2040	HIGH	USD2021/kW	670.61
PV tilted	VNM	2040	HIGH	USD2021/kW	460.61
Wind Offshore	DZA	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	ARG	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	AUS	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	BRA	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	CHL	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	CHN	2030	LOW	USD2021/kW	1.893.47
Wind Offshore	COL	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	CRI	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	DNK	2030	LOW	USD2021/kW	1.649.63
Wind Offshore	EGY	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	IND	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	IDN	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	JOR	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	KAZ	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	KEN	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	MRT	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	MEX	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	MAR	2030	LOW	USD2021/kW	2.378.79

Wind Offshore	NAM	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	NOR	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	PER	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	PRT	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	RUS	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	SAU	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	ZAF	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	ESP	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	SWE	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	THA	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	TUN	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	ARE	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	UKR	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	URY	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	USA	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	VNM	2030	LOW	USD2021/kW	2.378.79
Wind Offshore	DZA	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	ARG	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	AUS	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	BRA	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	CHL	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	CHN	2040	LOW	USD2021/kW	1.682.58
Wind Offshore	COL	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	CRI	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	DNK	2040	LOW	USD2021/kW	1.465.90
Wind Offshore	EGY	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	IND	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	IDN	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	JOR	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	KAZ	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	KEN	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	MRT	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	MEX	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	MAR	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	NAM	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	NOR	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	PER	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	PRT	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	RUS	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	SAU	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	ZAF	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	ESP	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	SWE	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	THA	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	TUN	2040	LOW	USD2021/kW	2.113.85

Wind Offshore	ARE	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	UKR	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	URY	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	USA	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	VNM	2040	LOW	USD2021/kW	2.113.85
Wind Offshore	DZA	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	ARG	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	AUS	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	BRA	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	CHL	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	CHN	2030	MEDIUM	USD2021/kW	1.949.83
Wind Offshore	COL	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	CRI	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	DNK	2030	MEDIUM	USD2021/kW	1.698.73
Wind Offshore	EGY	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	IND	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	IDN	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	JOR	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	KAZ	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	KEN	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	MRT	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	MEX	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	MAR	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	NAM	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	NOR	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	PER	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	PRT	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	RUS	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	SAU	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	ZAF	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	ESP	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	SWE	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	THA	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	TUN	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	ARE	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	UKR	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	URY	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	USA	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	VNM	2030	MEDIUM	USD2021/kW	2.449.59
Wind Offshore	DZA	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	ARG	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	AUS	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	BRA	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	CHL	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	CHN	2040	MEDIUM	USD2021/kW	1.766.98

Wind Offshore	COL	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	CRI	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	DNK	2040	MEDIUM	USD2021/kW	1.539.43
Wind Offshore	EGY	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	IND	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	IDN	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	JOR	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	KAZ	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	KEN	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	MRT	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	MEX	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	MAR	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	NAM	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	NOR	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	PER	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	PRT	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	RUS	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	SAU	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	ZAF	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	ESP	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	SWE	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	THA	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	TUN	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	ARE	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	UKR	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	URY	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	USA	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	VNM	2040	MEDIUM	USD2021/kW	2.219.88
Wind Offshore	DZA	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	ARG	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	AUS	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	BRA	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	CHL	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	CHN	2030	HIGH	USD2021/kW	2.075.32
Wind Offshore	COL	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	CRI	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	DNK	2030	HIGH	USD2021/kW	1.808.06
Wind Offshore	EGY	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	IND	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	IDN	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	JOR	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	KAZ	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	KEN	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	MRT	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	MEX	2030	HIGH	USD2021/kW	2.607.25

Wind Offshore	MAR	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	NAM	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	NOR	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	PER	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	PRT	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	RUS	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	SAU	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	ZAF	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	ESP	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	SWE	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	THA	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	TUN	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	ARE	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	UKR	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	URY	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	USA	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	VNM	2030	HIGH	USD2021/kW	2.607.25
Wind Offshore	DZA	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	ARG	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	AUS	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	BRA	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	CHL	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	CHN	2040	HIGH	USD2021/kW	1.954.93
Wind Offshore	COL	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	CRI	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	DNK	2040	HIGH	USD2021/kW	1.703.18
Wind Offshore	EGY	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	IND	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	IDN	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	JOR	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	KAZ	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	KEN	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	MRT	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	MEX	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	MAR	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	NAM	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	NOR	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	PER	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	PRT	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	RUS	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	SAU	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	ZAF	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	ESP	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	SWE	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	THA	2040	HIGH	USD2021/kW	2.456.01

Wind Offshore	TUN	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	ARE	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	UKR	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	URY	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	USA	2040	HIGH	USD2021/kW	2.456.01
Wind Offshore	VNM	2040	HIGH	USD2021/kW	2.456.01
Wind Onshore	DZA	2030	MEDIUM	USD2021/kW	1.158.70
Wind Onshore	ARG	2030	MEDIUM	USD2021/kW	1.006.32
Wind Onshore	AUS	2030	MEDIUM	USD2021/kW	935.71
Wind Onshore	BRA	2030	MEDIUM	USD2021/kW	723.72
Wind Onshore	CHL	2030	MEDIUM	USD2021/kW	883.46
Wind Onshore	CHN	2030	MEDIUM	USD2021/kW	758.42
Wind Onshore	COL	2030	MEDIUM	USD2021/kW	897.39
Wind Onshore	CRI	2030	MEDIUM	USD2021/kW	1.167.64
Wind Onshore	DNK	2030	MEDIUM	USD2021/kW	1.465.85
Wind Onshore	EGY	2030	MEDIUM	USD2021/kW	1.009.39
Wind Onshore	IND	2030	MEDIUM	USD2021/kW	771.58
Wind Onshore	IDN	2030	MEDIUM	USD2021/kW	1.179.33
Wind Onshore	JOR	2030	MEDIUM	USD2021/kW	1.158.70
Wind Onshore	KAZ	2030	MEDIUM	USD2021/kW	1.134.63
Wind Onshore	KEN	2030	MEDIUM	USD2021/kW	1.158.70
Wind Onshore	MRT	2030	MEDIUM	USD2021/kW	1.158.70
Wind Onshore	MEX	2030	MEDIUM	USD2021/kW	1.045.70
Wind Onshore	MAR	2030	MEDIUM	USD2021/kW	1.294.70
Wind Onshore	NAM	2030	MEDIUM	USD2021/kW	1.158.70
Wind Onshore	NOR	2030	MEDIUM	USD2021/kW	1.133.76
Wind Onshore	PER	2030	MEDIUM	USD2021/kW	897.39
Wind Onshore	PRT	2030	MEDIUM	USD2021/kW	1.118.13
Wind Onshore	RUS	2030	MEDIUM	USD2021/kW	1.125.48
Wind Onshore	SAU	2030	MEDIUM	USD2021/kW	1.179.33
Wind Onshore	ZAF	2030	MEDIUM	USD2021/kW	1.328.53
Wind Onshore	ESP	2030	MEDIUM	USD2021/kW	797.07
Wind Onshore	SWE	2030	MEDIUM	USD2021/kW	850.63
Wind Onshore	THA	2030	MEDIUM	USD2021/kW	1.179.33
Wind Onshore	TUN	2030	MEDIUM	USD2021/kW	1.158.70
Wind Onshore	ARE	2030	MEDIUM	USD2021/kW	1.134.63
Wind Onshore	UKR	2030	MEDIUM	USD2021/kW	908.68
Wind Onshore	URY	2030	MEDIUM	USD2021/kW	897.39
Wind Onshore	USA	2030	MEDIUM	USD2021/kW	838.53
Wind Onshore	VNM	2030	MEDIUM	USD2021/kW	1.184.36
Wind Onshore	DZA	2040	MEDIUM	USD2021/kW	1.044.61
Wind Onshore	ARG	2040	MEDIUM	USD2021/kW	907.24
Wind Onshore	AUS	2040	MEDIUM	USD2021/kW	843.58
Wind Onshore	BRA	2040	MEDIUM	USD2021/kW	652.46
Wind Onshore	CHL	2040	MEDIUM	USD2021/kW	796.47

Wind Onshore	CHN	2040	MEDIUM	USD2021/kW	683.74
Wind Onshore	COL	2040	MEDIUM	USD2021/kW	809.03
Wind Onshore	CRI	2040	MEDIUM	USD2021/kW	1.052.67
Wind Onshore	DNK	2040	MEDIUM	USD2021/kW	1.321.52
Wind Onshore	EGY	2040	MEDIUM	USD2021/kW	910.00
Wind Onshore	IND	2040	MEDIUM	USD2021/kW	695.61
Wind Onshore	IDN	2040	MEDIUM	USD2021/kW	1.063.21
Wind Onshore	JOR	2040	MEDIUM	USD2021/kW	1.044.61
Wind Onshore	KAZ	2040	MEDIUM	USD2021/kW	1.022.91
Wind Onshore	KEN	2040	MEDIUM	USD2021/kW	1.044.61
Wind Onshore	MRT	2040	MEDIUM	USD2021/kW	1.044.61
Wind Onshore	MEX	2040	MEDIUM	USD2021/kW	942.74
Wind Onshore	MAR	2040	MEDIUM	USD2021/kW	1.167.22
Wind Onshore	NAM	2040	MEDIUM	USD2021/kW	1.044.61
Wind Onshore	NOR	2040	MEDIUM	USD2021/kW	1.022.12
Wind Onshore	PER	2040	MEDIUM	USD2021/kW	809.03
Wind Onshore	PRT	2040	MEDIUM	USD2021/kW	1.008.03
Wind Onshore	RUS	2040	MEDIUM	USD2021/kW	1.014.66
Wind Onshore	SAU	2040	MEDIUM	USD2021/kW	1.063.21
Wind Onshore	ZAF	2040	MEDIUM	USD2021/kW	1.197.72
Wind Onshore	ESP	2040	MEDIUM	USD2021/kW	718.59
Wind Onshore	SWE	2040	MEDIUM	USD2021/kW	766.87
Wind Onshore	THA	2040	MEDIUM	USD2021/kW	1.063.21
Wind Onshore	TUN	2040	MEDIUM	USD2021/kW	1.044.61
Wind Onshore	ARE	2040	MEDIUM	USD2021/kW	1.022.91
Wind Onshore	UKR	2040	MEDIUM	USD2021/kW	819.21
Wind Onshore	URY	2040	MEDIUM	USD2021/kW	809.03
Wind Onshore	USA	2040	MEDIUM	USD2021/kW	755.97
Wind Onshore	VNM	2040	MEDIUM	USD2021/kW	1.067.74
Wind Onshore	DZA	2030	LOW	USD2021/kW	1.109.14
Wind Onshore	ARG	2030	LOW	USD2021/kW	963.28
Wind Onshore	AUS	2030	LOW	USD2021/kW	895.69
Wind Onshore	BRA	2030	LOW	USD2021/kW	692.77
Wind Onshore	CHL	2030	LOW	USD2021/kW	845.67
Wind Onshore	CHN	2030	LOW	USD2021/kW	725.98
Wind Onshore	COL	2030	LOW	USD2021/kW	859.01
Wind Onshore	CRI	2030	LOW	USD2021/kW	1.117.70
Wind Onshore	DNK	2030	LOW	USD2021/kW	1.403.16
Wind Onshore	EGY	2030	LOW	USD2021/kW	966.22
Wind Onshore	IND	2030	LOW	USD2021/kW	738.58
Wind Onshore	IDN	2030	LOW	USD2021/kW	1.128.89
Wind Onshore	JOR	2030	LOW	USD2021/kW	1.109.14
Wind Onshore	KAZ	2030	LOW	USD2021/kW	1.086.10
Wind Onshore	KEN	2030	LOW	USD2021/kW	1.109.14
Wind Onshore	MRT	2030	LOW	USD2021/kW	1.109.14

Wind Onshore	MEX	2030	LOW	USD2021/kW	1.000.98
Wind Onshore	MAR	2030	LOW	USD2021/kW	1.239.32
Wind Onshore	NAM	2030	LOW	USD2021/kW	1.109.14
Wind Onshore	NOR	2030	LOW	USD2021/kW	1.085.27
Wind Onshore	PER	2030	LOW	USD2021/kW	859.01
Wind Onshore	PRT	2030	LOW	USD2021/kW	1.070.30
Wind Onshore	RUS	2030	LOW	USD2021/kW	1.077.34
Wind Onshore	SAU	2030	LOW	USD2021/kW	1.128.89
Wind Onshore	ZAF	2030	LOW	USD2021/kW	1.271.71
Wind Onshore	ESP	2030	LOW	USD2021/kW	762.98
Wind Onshore	SWE	2030	LOW	USD2021/kW	814.25
Wind Onshore	THA	2030	LOW	USD2021/kW	1.128.89
Wind Onshore	TUN	2030	LOW	USD2021/kW	1.109.14
Wind Onshore	ARE	2030	LOW	USD2021/kW	1.086.10
Wind Onshore	UKR	2030	LOW	USD2021/kW	869.82
Wind Onshore	URY	2030	LOW	USD2021/kW	859.01
Wind Onshore	USA	2030	LOW	USD2021/kW	802.67
Wind Onshore	VNM	2030	LOW	USD2021/kW	1.133.70
Wind Onshore	DZA	2040	LOW	USD2021/kW	984.50
Wind Onshore	ARG	2040	LOW	USD2021/kW	855.03
Wind Onshore	AUS	2040	LOW	USD2021/kW	795.04
Wind Onshore	BRA	2040	LOW	USD2021/kW	614.92
Wind Onshore	CHL	2040	LOW	USD2021/kW	750.64
Wind Onshore	CHN	2040	LOW	USD2021/kW	644.40
Wind Onshore	COL	2040	LOW	USD2021/kW	762.48
Wind Onshore	CRI	2040	LOW	USD2021/kW	992.10
Wind Onshore	DNK	2040	LOW	USD2021/kW	1.245.48
Wind Onshore	EGY	2040	LOW	USD2021/kW	857.64
Wind Onshore	IND	2040	LOW	USD2021/kW	655.58
Wind Onshore	IDN	2040	LOW	USD2021/kW	1.002.03
Wind Onshore	JOR	2040	LOW	USD2021/kW	984.50
Wind Onshore	KAZ	2040	LOW	USD2021/kW	964.05
Wind Onshore	KEN	2040	LOW	USD2021/kW	984.50
Wind Onshore	MRT	2040	LOW	USD2021/kW	984.50
Wind Onshore	MEX	2040	LOW	USD2021/kW	888.49
Wind Onshore	MAR	2040	LOW	USD2021/kW	1.100.05
Wind Onshore	NAM	2040	LOW	USD2021/kW	984.50
Wind Onshore	NOR	2040	LOW	USD2021/kW	963.31
Wind Onshore	PER	2040	LOW	USD2021/kW	762.48
Wind Onshore	PRT	2040	LOW	USD2021/kW	950.03
Wind Onshore	RUS	2040	LOW	USD2021/kW	956.28
Wind Onshore	SAU	2040	LOW	USD2021/kW	1.002.03
Wind Onshore	ZAF	2040	LOW	USD2021/kW	1.128.80
Wind Onshore	ESP	2040	LOW	USD2021/kW	677.24
Wind Onshore	SWE	2040	LOW	USD2021/kW	722.75

Wind Onshore	THA	2040	LOW	USD2021/kW	1.002.03
Wind Onshore	TUN	2040	LOW	USD2021/kW	984.50
Wind Onshore	ARE	2040	LOW	USD2021/kW	964.05
Wind Onshore	UKR	2040	LOW	USD2021/kW	772.07
Wind Onshore	URY	2040	LOW	USD2021/kW	762.48
Wind Onshore	USA	2040	LOW	USD2021/kW	712.47
Wind Onshore	VNM	2040	LOW	USD2021/kW	1.006.30
Wind Onshore	DZA	2030	HIGH	USD2021/kW	1.270.53
Wind Onshore	ARG	2030	HIGH	USD2021/kW	1.103.44
Wind Onshore	AUS	2030	HIGH	USD2021/kW	1.026.02
Wind Onshore	BRA	2030	HIGH	USD2021/kW	793.57
Wind Onshore	CHL	2030	HIGH	USD2021/kW	968.72
Wind Onshore	CHN	2030	HIGH	USD2021/kW	831.62
Wind Onshore	COL	2030	HIGH	USD2021/kW	984.00
Wind Onshore	CRI	2030	HIGH	USD2021/kW	1.280.33
Wind Onshore	DNK	2030	HIGH	USD2021/kW	1.607.33
Wind Onshore	EGY	2030	HIGH	USD2021/kW	1.106.81
Wind Onshore	IND	2030	HIGH	USD2021/kW	846.05
Wind Onshore	IDN	2030	HIGH	USD2021/kW	1.293.15
Wind Onshore	JOR	2030	HIGH	USD2021/kW	1.270.53
Wind Onshore	KAZ	2030	HIGH	USD2021/kW	1.244.14
Wind Onshore	KEN	2030	HIGH	USD2021/kW	1.270.53
Wind Onshore	MRT	2030	HIGH	USD2021/kW	1.270.53
Wind Onshore	MEX	2030	HIGH	USD2021/kW	1.146.63
Wind Onshore	MAR	2030	HIGH	USD2021/kW	1.419.65
Wind Onshore	NAM	2030	HIGH	USD2021/kW	1.270.53
Wind Onshore	NOR	2030	HIGH	USD2021/kW	1.243.18
Wind Onshore	PER	2030	HIGH	USD2021/kW	984.00
Wind Onshore	PRT	2030	HIGH	USD2021/kW	1.226.04
Wind Onshore	RUS	2030	HIGH	USD2021/kW	1.234.10
Wind Onshore	SAU	2030	HIGH	USD2021/kW	1.293.15
Wind Onshore	ZAF	2030	HIGH	USD2021/kW	1.456.75
Wind Onshore	ESP	2030	HIGH	USD2021/kW	874.00
Wind Onshore	SWE	2030	HIGH	USD2021/kW	932.73
Wind Onshore	THA	2030	HIGH	USD2021/kW	1.293.15
Wind Onshore	TUN	2030	HIGH	USD2021/kW	1.270.53
Wind Onshore	ARE	2030	HIGH	USD2021/kW	1.244.14
Wind Onshore	UKR	2030	HIGH	USD2021/kW	996.38
Wind Onshore	URY	2030	HIGH	USD2021/kW	984.00
Wind Onshore	USA	2030	HIGH	USD2021/kW	919.46
Wind Onshore	VNM	2030	HIGH	USD2021/kW	1.298.66
Wind Onshore	DZA	2040	HIGH	USD2021/kW	1.184.86
Wind Onshore	ARG	2040	HIGH	USD2021/kW	1.029.04
Wind Onshore	AUS	2040	HIGH	USD2021/kW	956.84
Wind Onshore	BRA	2040	HIGH	USD2021/kW	740.06

Wind Onshore	CHL	2040	HIGH	USD2021/kW	903.40
Wind Onshore	CHN	2040	HIGH	USD2021/kW	775.54
Wind Onshore	COL	2040	HIGH	USD2021/kW	917.65
Wind Onshore	CRI	2040	HIGH	USD2021/kW	1.194.00
Wind Onshore	DNK	2040	HIGH	USD2021/kW	1.498.95
Wind Onshore	EGY	2040	HIGH	USD2021/kW	1.032.18
Wind Onshore	IND	2040	HIGH	USD2021/kW	789.00
Wind Onshore	IDN	2040	HIGH	USD2021/kW	1.205.95
Wind Onshore	JOR	2040	HIGH	USD2021/kW	1.184.86
Wind Onshore	KAZ	2040	HIGH	USD2021/kW	1.160.25
Wind Onshore	KEN	2040	HIGH	USD2021/kW	1.184.86
Wind Onshore	MRT	2040	HIGH	USD2021/kW	1.184.86
Wind Onshore	MEX	2040	HIGH	USD2021/kW	1.069.31
Wind Onshore	MAR	2040	HIGH	USD2021/kW	1.323.93
Wind Onshore	NAM	2040	HIGH	USD2021/kW	1.184.86
Wind Onshore	NOR	2040	HIGH	USD2021/kW	1.159.35
Wind Onshore	PER	2040	HIGH	USD2021/kW	917.65
Wind Onshore	PRT	2040	HIGH	USD2021/kW	1.143.37
Wind Onshore	RUS	2040	HIGH	USD2021/kW	1.150.89
Wind Onshore	SAU	2040	HIGH	USD2021/kW	1.205.95
Wind Onshore	ZAF	2040	HIGH	USD2021/kW	1.358.52
Wind Onshore	ESP	2040	HIGH	USD2021/kW	815.06
Wind Onshore	SWE	2040	HIGH	USD2021/kW	869.83
Wind Onshore	THA	2040	HIGH	USD2021/kW	1.205.95
Wind Onshore	TUN	2040	HIGH	USD2021/kW	1.184.86
Wind Onshore	ARE	2040	HIGH	USD2021/kW	1.160.25
Wind Onshore	UKR	2040	HIGH	USD2021/kW	929.20
Wind Onshore	URY	2040	HIGH	USD2021/kW	917.65
Wind Onshore	USA	2040	HIGH	USD2021/kW	857.46
Wind Onshore	VNM	2040	HIGH	USD2021/kW	1.211.09

14 Annex II: Data per country for WACC

region	final_value
DZA	14.6%
ARG	22.2%
AUS	4.6%
BRA	9.0%
CHL	5.8%
CHN	7.2%
CRI	11.2%
COL	7.4%
DNK	4.6%
EGY	15.6%
IND	7.8%
IDN	7.4%
JOR	11.2%
KAZ	7.4%
KEN	14.1%
MRT	14.6%
MEX	7.4%
MAR	8.3%
NAM	11.2%
NOR	4.6%
PER	6.9%
PRT	6.4%
RUS	18.9%
SAU	5.6%
ZAF	9.0%
ESP	6.9%
SWE	4.6%
THA	6.9%
TUN	17.8%
UKR	22.2%
ARE	5.3%
URY	7.4%
USA	4.6%
VNM	9.0%

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