Comparative techno-economic potential study to produce green hydrogen products via CSP-PV-hybrid-power-plants for MENA

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Abbreviations

AEL	Alkaline Electrolysis
ASU	Air Separation Unit
BESS	Battery Energy Storage System
C&I	Commercial and Industrial
CAPEX	Capital expenditures
CF	Capacity factor (refers to yearly average, if not stated otherwise)
CSP	Concentrated Solar Power
DNI	Direct normal irradiance
ENI	global energy company
EU	European Union
GCR	Ground Coverage Ratios
GHG	Greenhouse gas
H_2	Hydrogen
HB	Haber-Bosch
HJT	Heterojunction cells
HT	High temperature
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
KPI	Key Performance Indicator
LCOE	Levelized Cost of Electricity
LCOX	Levelized cost of PtX Production
LID	Light Induced Degradation
MeOH	Methanol
MILP	Mixed-Integer Linear Programming
MT	Medium temperature
NDCs	Nationally Determined Contributions
N_2	Nitrogen

NH_3	Ammonia
OPEX	Operational expenditures
PEM	Proton Exchange Membrane
PERC	Passivated Emitter and Rear Cell
PtX	Power-to-X
PV	(Solar) Photovoltaic
RE/RES	Renewable Energy (Sources)
REPower	EU regulations and legislative act
RFNBO	Renewable Fuels of Non-Biological Origin
SOEL	Solid Oxide Electrolysis
TCO	Total cost of ownership (discounted, whole project period)
TES	Thermal Energy Storage
TOPCon	Tunnel Oxide Passivated Contact
TRL	Technology Readiness Level
VRE	Volatile Renewable Energy
WB	The World Bank

Executive Summary

This study offers a comprehensive assessment, focusing on the techno-economic analysis of hybrid power plants consisting of Concentrated Solar Power and Solar photovoltaic (CSP-PV hybrid systems) to produce green hydrogen (H_2), green ammonia (NH_3), and green methanol (MeOH) in the MENA region using exemplary data (renewable energy potentials) for sites in Algeria, Morocco, and Tunisia. The report evaluates the competitiveness of CSP-PV hybrid systems in comparison to PV and wind hybrid systems, as well as other configurations across a range of scenarios and takes into account various performance indicators, including costs, environmental impact, and social factors.

General Assumptions: The analysis relies on techno-economic parameters from existing literature and consultant expertise. CAPEX and OPEX encompasses various system components. Further different RE potentials depending on exemplary sites and different technology design, are also considered. These assumptions are presented in different scenarios with varying combinations to account for future uncertainties and explore diverse possibilities. The spatial distribution is adaptable, assuming co-location of renewable generation and PtX processes. Factors like byproducts, marine shipping, and related infrastructure are not within the scope. Data verification is conducted using reference values and consultant experience.

Modelling Method: The analysis employs PROSUMER[1] modelling software, enabling detailed hourly modelling of PtX production stages. It adopts a bottom-up approach using mixed-integer linear programming (MILP) optimization. Input parameters encompass cost items, operational characteristics, and renewable energy generation profiles. Consequently, the PROSUMER model determines optimal asset capacities (e.g., VRE generator capacities relative to electrolyzer size and hydrogen/battery/thermal energy storage capacity) and optimal asset operation (yearly and hourly dispatch) to minimize the production cost of green hydrogen, ammonia and methanol over the facility's lifespan.

Scenario Definition: A comprehensive multi-dimensional scenario analysis is conducted to encompass a wide range of potential framework conditions for PtX projects. Various dimensions and manifestations are considered:

- **Sites:** Five representative site locations in Algeria, Morocco, and Tunisia are under consideration, with at least one per country.
- **Technologies and System Selection:** Two scenarios are examined: a technology-open scenario comprising CSP, PV, wind, and storage options, and a CSP/PV hybrid scenario excluding wind. The objective of these scenarios is to compare CSP-PV hybrid systems against other configurations.
- **PtX Product Cases:** This analysis encompasses three key PtX commodities: green hydrogen, green ammonia, and green methanol. The production of hydrogen relies on electrolysis, while both NH_3 and MeOH production require hydrogen as a fundamental input. NH_3 and MeOH synthesis are not modelled explicitly, but implicitly by definition of respective Hydrogen demand profiles.
- **Time Horizons: 2030 vs. 2050:** In this study, two critical time horizons are examined: 2030 as a baseline reference point and 2050 to project potential future developments. The latter assumes cost reductions for specific components but maintains other critical parameters for the sake of consistency.

The combination of these scenarios results in a total of 60 distinct cases.

Key Performance Indicators (KPI): The different scenarios are evaluated and compared by five KPIs which encompass various aspects:

- Economic: Capital Expenditure (CAPEX), Operational Expenditure (OPEX), and LCOX.
- Ecological: Water demand and land use.
- Social: Number of jobs created.

[1] Consultant's in-house modelling environment. See: Appendix C: PROSUMER Tool description

Main results

- Single CSP-PV hybrid systems have economic advantages in regions with abundant solar resources.
- CSP is an economically viable supplementary energy source for high base load scenarios, particularly when considering methanol production.
- However, in most cases, hybrid systems combining wind and solar technologies (CSP and PV) outperform single CSP-PV hybrid systems.
- The combination of an electric heater, thermal energy storage, and a power block has demonstrated the ability to outperform battery energy storage, even without the integration of solar thermal collectors.
- Alkaline electrolysis is the preferred technology for PtX production in 2030 over solid oxide electrolysis. Proton Exchange Membrane was not included in the technology mix and could therefore not be selected.
- When Solid Oxide Electrolysis (SOEL) become affordable, CSP becomes more attractive as it can provide additional renewable thermal energy, avoiding heat-to-power solutions with conversion losses.
- Solar tower systems are the preferred CSP technology over parabolic trough systems, as it achieves higher capacity factors (lower LCOE).

1 Introduction

To establish a global hydrogen economy, knowledge transfer about the interaction of different renewable energy systems (RES), downstream electrolysis processes as well as the further chemical conversion processes are necessary. Therefore technology-open potential and profitability analyses for different production processes are required, including different technology options for the generation of renewable energies up to the production of green hydrogen products. For the successful and competitive market integration of green hydrogen products in particular, high efficiencies in the whole production process are necessary. High plant capacity factors are advantageous for this.

To align the need of a constant hydrogen flow with the fluctuating production of RES, storage facilities can be used. In this context, concentrated solar power (CSP) can have advantages over fluctuating renewable energy source (RES), such as PV and wind power as CSP offers the possibility of storing energy in the form of heat, and CSP can produce in addition to electricity, high-temperature heat, which can be used as a feedstock for downstream processes such as high-temperature electrolysis. But on the other hand, CSP has higher investment costs compared to other RES, such as PV and wind. Therefore, a techno-economic analysis of CSP-PV hybrid power plants for the production of green hydrogen products is important.

The main objective of this analysis is to evaluate the competitiveness of CSP-PV hybrid systems for PtX projects for the production of green H_2, NH_3, and MeOH. To achieve this, a scenario analysis that encompasses five distinct geographical locations, two technology pools, three target products, and two different time horizons is conducted. This comprehensive approach results in a total of 60 cases under consideration.

For each of these 60 scenarios, a least-cost optimization process was conducted to determine the most favourable system design and operation. Based on the results of the optimization for each scenario five key performance indicators (KPIs) were evaluated. To ensure the robustness and relevance of the findings, the analysis was benchmarked against reference values obtained from the consultant’s expertise of prior projects and scientific literature.

The report is structured as follows: Chapter 2 provides a technology review. Based on the review and system specification, Chapter 3 details the techno-economic analysis of all scenarios and sites. Chapter 4 presents the key modelling results. Chapter 5 gives a conclusion.

2 Literature Review

This chapter provides a comprehensive technology review. This includes a review on the analysed **renewable energy sources** for electricity generation: mainly photovoltaic (PV), wind turbines, and concentrated solar power (CSP) and a review of technologies for the **production and storage of green hydrogen and its derivatives**. For each technology the following aspects have been deeply analysed:

- **Technologies and performances**: This section evaluates the performance of various technology types, including their capacity factor, technological readiness, water usage, employment or land use.
- **Current costs and cost projections:** The upfront costs and levelized cost of electricity (LCOE) are assessed in this section, with future projections up to 2030 and 2050 based on the review presented.
- **Current use in the targeted** countries: This section examines the current use of renewable energy technologies in Algeria, Morocco, and Tunisia.

The results of the review are used to facilitate the design and modelling of the scenarios for green PtX production. However, the used input data and additional performance indicators such as area requirements, water needs, and employment can be found in the Appendices A and B.

2.1 Technology review: CSP

2.1.1 Technologies and Performances

CSP is a type of renewable energy technology that uses mirrors or lenses to focus sunlight onto a small area, which produces heat that can be used to generate electricity. There are several types of CSP technologies.

- **Parabolic trough systems** are the most mature CSP technology and currently make up the majority of installed CSP capacity. They use parabolic-shaped mirrors to focus sunlight onto a receiver tube, where a heat transfer fluid is heated and used to generate steam to drive a turbine and produce electricity. Parabolic troughs have achieved an optical efficiency of up to 80%, and some plants have achieved capacity factors of over 70%, meaning they operate at a high percentage of their maximum capacity over time (IRENA 2013).
- **Central Receiver Systems** (“Solar tower”) show highest efficiencies compared to other CSP technologies due to higher operating temperatures and have become more prominent in recent commercial installations.
- **Dish/engine systems** use a parabolic dish to concentrate sunlight onto a receiver at the focal point, which heats a working fluid to drive a Stirling engine or other heat engine to produce electricity. Dish/engine systems have demonstrated solar to electricity efficiencies of up to 31%, but they are currently less mature and have much lower installed capacity than other CSP technologies.
- **Linear Fresnel** reflectors use rows of flat mirrors or reflectors to focus sunlight onto a stationary receiver, like a parabolic trough system. Linear Fresnel systems are less mature than parabolic troughs but have the potential to be less expensive due to their simpler design and use of fewer components.

CSP has a very high TLR scale of 9, meaning the system is proven in a commercial operational environment. CSP has a long commercial track record since over 40 years, however, at the same time with a comparatively low market penetration. Thus, CSP technologies such as parabolic trough, linear Fresnel and central receiver system have a high TRL (“System fully operational and ready for commercialization”) with a proven commercial operation since over 40 years. The Technology Readiness Level (TRL) is a measure used to assess the maturity of a technology, with TRL 1 being the lowest level of development and TRL 9 being the highest level of development according to EU (EY, 2017)[2].

The current trend in CSP is towards larger installations using higher temperature which can be reached only by central receiver systems using molten salt as heat transfer fluid. Single installations have installed generator capacities of 100 to 150 MW_e with perspective towards 200 MW_e. As the thermal storage in CSP has become an integral part of the installation – i.e. no installation without thermal storage has been realized in the recent past – the capacity factors of CSP plants are not comparable to those

[2] However, IEA uses another scale TRL 1 to TRL 11 special for electrolysers, see the next chapters

of other standalone renewable energy sources such as PV and wind depending on the storage size, it can reach up to 70% (API 2016).

2.1.2 Current Costs and Cost Projections

Between 2010 and 2021, CSP global weighted average cost of electricity fell from USD 0.358/kWh to USD 0.114/kWh – a decline of 68%. The capital costs for CSP projects commissioned in 2020 ranged from USD 4449 USD/kW for parabolic trough to 5339 USD/kW for solar tower (IRENA, 2021).

The trend in CSP is now towards higher temperatures and larger installations in order to increase thermal performance and reduce specific costs. storage options with CSP is cheaper, which makes CSP the preferred solar energy technology for baseload needs.

2.1.3 Current usage of CSP, potentials and barriers in Algeria, Morocco and Tunisia

Of the total 6.5 GW of CSP capacity installed worldwide (IRENA, 2023b), 0.54 GW (8.3%) are installed in Morocco and specific 0.025 GW (0.4%) in Algeria. There is no commercial CSP installation in Tunisia.
Both Morocco and Algeria started with hybridized combined cycles, but only Morocco nowadays has CSP stand-alone installations in commercial operation, notably the NOOR projects with 510 MW installed capacity. The largest CSP capacities outside of the MENA region are installed in Spain, USA, and China.

Table 1: Installed capacities, potentials, and barriers of CSP in Algeria, Morocco and Tunisia

Country	Economic potential of CSP implementation[3]	Installed CSP Capacity	Capacity Factor in Selected Regions	Sources
Algeria	168,972 TWh/a	25 MW (as hybrid portion)	Hassi R'mel 0.94 as hybrid portion	(DLR 2005), (IRENA, 2023b)
Tunisia	9,244 TWh/a	n.a	n.a.	(DLR 2005), (IRENA, 2023b)
Morocco	20,146 TWh/a	540 MW (including hybrid portion)	NOOR 0.51 Ain Beni Mathar 0.29	(DLR 2005), (IRENA, 2023b)

Mainly parabolic trough CSPs technologies have been installed in MENA countries at present. However, solar tower CSP technology was installed in Morocco in 2019 as well (WB, 2020).

2.2 Technology review: Wind energy

2.2.1 Technologies and Performances

Wind turbines have been developed over several decades and are a mature technology with high TRL scale of TLR 9 (EY, 2021). The trend towards more advanced and more efficient turbine technologies with larger rotor diameters and hub-heights has resulted in a rise in energy outputs and capacity factors in most markets. The global weighted average total capacity factor of wind energy was estimated to be around 39% (IRENA, 2021). Advances in wind turbine technology and increased installation in remote and offshore locations are expected to drive continued growth in wind power generation. In addition, the development of energy storage solutions and grid integration technologies are expected to further enhance the flexibility and reliability of wind power generation.

[3] from DNI and CSP site mapping taking sites with DNI > 2000 kWh/m²/y as economic

2.2.2 Current Costs and Cost Projections

The LCOE for onshore wind energy is declining, while the LCOE for offshore wind energy is becoming more competitive with other forms of energy generation. The global weighted average LCOE of new onshore wind projects added in 2021 fell by 15%, year-on-year while that offshore wind declined 13% (IRENA, 2021).

Cost projections for wind energy suggest that the LCOE for both onshore and offshore wind energy will continue to decline in the coming years due to technological improvements, economies of scale, and policy support. The cost projections of wind turbines are summarised in the Table 2.

Table 2: Costs projections of wind turbines (IRENA, 2021)

Costs categories	Onshore Wind Energy	Offshore Wind Energy
LCOE Projections 2030	0.03 to 0.05 USD/kWh	USD 0.05 to 0.09 USD/kWh
LCOE Projections 2050	0.02 to 0.03 USD/kWh	USD 0.03 to 0.07 USD/kWh
CAPEX 2030	800 to 1,350 USD/kW	1,700 to 3,200 USD/kW
CAPEX 2050	650 to 1,000 USD/kW	1,400 to 2,800 USD/kW

2.2.3 Current usage of wind energy, potentials and barriers in Algeria, Morocco and Tunisia

The highest installed capacity of wind turbines is found in Morocco (2787 MW, potential: ~25 GW), followed by Tunisia (245 MW, potential: ~8 GW) and Algeria (10 MW, potential: <20 GW). Also, the best capacity factor, i.e., better annual wind conditions are found to be in Morocco (up to 56%). The potential for wind capacity depends also on institutional or policy-related aspect. Some of the barriers in the examined countries are: System stability issues due to the intermittency of wind, high upfront costs, lack of skilled technicians and engineers, lack of coordination between political groups/public institutions.

2.3 Technology review: solar PV

2.3.1 Technologies and Performances

PV technology has improved significantly in recent years, particularly in terms of performance, efficiency and reliability, while new technologies are emerging. Module technology has evolved to become increasingly application driven to match the requirements of residential, commercial and industrial (C&I) sector, utility scale, floating PV, agri-PV and other types of systems. This resulted in a range of different module sizes, structures (frame/frameless), materials (glass/glass, doping replacement) and the availability of a range bifacial modules for different applications. The design type and parameters on system level have become more differentiated as well to comply with application requirements. PV systems have been developed over several decades and are a mature technology with high TRL scale of TLR 9 (EY, 2021).

The global weighted average capacity factor for a new, utility-scale solar PV increased from 13.8% in 2010 to 17.2% in 2021 (IRENA, 2021).

2.3.2 Current Costs and Cost Projections

Technological progress has a direct impact on the cost of electricity generation, which is best expressed in terms of LCOE. Lowering CAPEX, OPEX and increased energy yield with a lower annual degradation leads to lower LCOE while widening the spread with conventional generation technologies, taking into account that gas and nuclear costs have increased. The table below shows that LCOE is trending on average towards 16-33 USD/MWh short/mid-term and 12-21 USD/MWh long-term. Cost reduction is widely achieved thanks to increased efficiencies, learning curves of manufacturer and EPCs in optimizing their production and design methods and finally due to a massive increase in volume production which allowed for cost reduction along the value chain. It is important to add that PV projects are capital intensive and therefore quite sensitive to interest rates fluctuations.

Cost estimates focus on utility scale solar PVs. The costs projections of PVs are summarised in the Table 3.

Table 3: Costs projections of utility scale PVs (NREL, 2021)

Costs categories	Utility scale PV
LCOE Projections 2030	16.34-33.3 USD/MWh
LCOE Projections 2050	12.25-20.7 USD/MWh
CAPEX 2030	638 to 1,182 USD/kW
CAPEX 2050	481 to 776 USD/kW

2.3.3 Current usage of solar PV energy, potentials and barriers in Algeria, Morocco and Tunisia

The following table summarizes key PV projects in the target countries based on insights of MESIA's Solar Outlook Report (MESIA, 2022) and IRENA renewable energy capacity statistics (IRENA, 2023):

Table 4: PV projects and experiences of projects in target countries

Country	Projects	Cumulated installed Capacity 2023
Algeria	1 GW Tender, 11 sites in southern Algeria, tender phase 50 MW GREG-Biskra Project (awarded)	435 MW (IRENA, 2023, third party source)
Morocco	800 MW, CSP-PV Noor Midelt I, awarded, no financial close yet 400 MW Noor II PV, 6 locations (under evaluation)	318 MW (IRENA, 2023, estimated)
Tunisia	3rd Rd 500 MW Solar Tender (on hold): 200 MW, Tatouine 2x100 MW Kaiouran/Gafsa 2x50 MW Sidi Bouzid/Tozeur 4th Rd: 70 MW Solar Tender, 16 projects: 10 x 1 MW, 6 x 10 MW (Bid evaluation, on hold)	197 MW (IRENA, 2023, estimated)

MESIA (2022) identifies several challenges for large scale PV installations and for PtX economy development.

- **Tunisia:** Despite the potential for large utility scale and C&I renewable energy installation, the projects are delayed or postponed.
- **Morocco:** Challenges are still present within the country's legal framework to enable more opportunities for solar market players. Other challenges are achieving a price for green hydrogen that can compete with grey hydrogen, and the conversion and transport of green ammonia or methanol for export.

2.4 Technology review: Water electrolysis

2.4.1 Technologies and Performance

The Current mature technologies for water electrolysis are alkaline electrolysis (AEL) and Proton-Exchange-Membrane (PEM) electrolysis. According to (IEA, 2022a) both AEL and PEM technology are considered as commercially available technologies with TRL 9 (early adoption[4]). High-temperature solid oxide electrolysis (SOEL), operating at high-temperature steam, is an emerging technology, which is considered TRL 7 (demonstration).

[4] TLR scale refers to the IEA definition, special for Electrolyzers TRL 1 to TRL 11 scale. **Electrolyzers – Analysis – IEA**

The current and prospective KPIs for the three considered electrolyser technologies (AEL, PEM, SOEL) are presented in detail in Appendix A. When all technologies are compared against each other, the SOEL technology has the highest system efficiency but is not yet available in the higher scale ranges. When comparing only commercially available technologies, AEL has a slightly higher efficiency compared to PEM. However, since AEL is typically operating at atmospheric pressure levels, additional energy demand for mechanical compression needs to be considered to deliver hydrogen at the same pressure level than PEM systems.

The KPIs for the year 2030 and beyond show that further technology improvements are expected. The overall system efficiencies for the three electrolyser technologies are expected to be improved compared to the current status. SOEL is expected to become commercially available at the 100 MW scale by 2030.

2.4.2 Current Costs and Cost Projections

1.1.1.1 Current status

The specific[5] investment costs (CAPEX) and operating costs (fixed OPEX) for AEL, PEM and SOEL electrolysis systems are shown in Table 5, Table 6 and Table 7. Currently, AEL systems are available at the lowest specific CAPEX. In terms of OPEX however, PEM system require lower operating costs. It general it can be observed that the specific CAPEX decreases with the increasing plant scale (economies of scale) for both AEL and PEM technology (see Table 5 and Table 6 respectively). For SOEL there is no reliable information on different plant sizes.
The lowest operating costs are achieved with PEM technology. The operating costs for AEL compared to PEM are higher because of the used caustic electrolyte, which requires higher maintenance efforts (Fraunhofer ISE, 2021). Regarding the plant scale, no difference for the specific OPEX is reported in the literature. However, it can be expected that for large-scale systems, specific OPEX will decrease due to scaling effects.
For the SOEL technology both the specific CAPEX and OPEX are currently higher compared to the AEL and PEM technology.

Table 5: Current investment and operating cost of AEL electrolysis

KPI	Unit	Value	Source
Specific fixed OPEX	EUR/(kW*a)	20 ± 5	(Fraunhofer ISE, 2021)
Specific CAPEX **5 MW scale**	EUR/kW	949	(Fraunhofer ISE, 2021)
Specific CAPEX **100 MW scale**	EUR/kW	663	(Fraunhofer ISE, 2021)

Table 6: Current investment and operating cost of PEM electrolysis

KPI	Unit	Value	Source
Specific fixed OPEX	EUR/(kW*a)	15 ± 5	(Fraunhofer ISE, 2021)
Specific CAPEX **5 MW scale**	EUR/kW	978	(Fraunhofer ISE, 2021)
Specific CAPEX **100 MW scale**	EUR/kW	718	(Fraunhofer ISE, 2021)

[5] Specific CAPEX and OPEX are referring to the rated stack power in kW.

Table 7: Current investment and operating cost of SOEL electrolysis

KPI	Unit	Value	Source
Specific CAPEX	EUR/kW	2250	(NOW, 2018)
Specific fixed OPEX	EUR/(kW*a)	32.5	(NOW, 2018)

1.1.1.2 Medium-term 2030

Table 7, Table 8 and Table 9 show the expected cost developments until 2030 for AEL, PEM and SOEL technologies respectively. Additionally, for the AEL and PEM technologies, the specific CAPEX for the 1 GW plant scale are shown.
The AEL electrolysis is expected to maintain a slight cost advantage over PEM electrolysis in terms of CAPEX. However, it can be expected that the cost difference between AEL and PEM electrolysis is reduced compared to the current status. According to NOW (2018), significant cost reduction potential is assumed for SOEL electrolysis, which is expected to achieve lower CAPEX compared to AEL and PEM. However, due to the early market status of SOEL this forecast will have to be proven.
The economy of scale effect is expected to further decrease the specific CAPEX of AEL and PEM systems in the medium-term, not only due to technology improvement, but also considering further upscaling of electrolysis plants towards the 1 GW scale.

Table 8: Expected investment and operating cost of AEL electrolysis in 2030

KPI	Unit	Value	Source
Specific fixed OPEX	EUR/(kW*a)	N/A[6]	
Specific CAPEX **5 MW scale**	EUR/kW	726	(Fraunhofer ISE, 2021)
Specific CAPEX **100 MW scale**	EUR/kW	444	(Fraunhofer ISE, 2021)
Specific CAPEX **1 GW scale**	EUR/kW	420	(ISPT, 2022)

Table 9: Expected investment and operating cost of PEM electrolysis in 2030

KPI	Unit	Value	Source
Specific fixed OPEX	EUR/(kW*a)	N/A[7]	
Specific CAPEX **5 MW scale**	EUR/kW	729	(Fraunhofer ISE, 2021)
Specific CAPEX **100 MW scale**	EUR/kW	502	(Fraunhofer ISE, 2021)
Specific CAPEX **1 GW scale**	EUR/kW	450	ISPT (2022)

Table 10: Expected investment and operating cost of SOEL electrolysis in 2030

KPI	Unit	Value	Source
Specific CAPEX	EUR/kW	480	(NOW, 2018)
Specific fixed OPEX	EUR/(kW*a)	12	(NOW, 2018)

[6] Expected to be lower than the current level (Fraunhofer ISE (2021))
[7] Expected to be lower than the current level and lower than AEL level (Fraunhofer ISE (2021))

2.4.3 Current usage of electrolysis, potentials and barriers in Algeria, Morocco, and Tunisia

According to the information currently available it can be inferred that there are no operational electrolysis plants in Algeria, Morocco, and Tunisia dedicated to the production of green hydrogen.
However, several projects in Morocco have been announced with a time frame up to 2030 according to (Öko-Institut e.V., 2022). The announced projects are ranging from 1-100 MW electrolysis capacity.

Table 11: Electrolysis projects in the selected countries

Country	Existing projects	Announced projects	Sources
Algeria	None in the IEA Database 2022	Feasibility study | Sonatrach (state owned) & ENI (Italy) | green hydrogen	(IEA, 2022b), (Öko-Institut e.V., 2022)
Morocco	None in the IEA Database 2022	• (not reported) MW | Starting 2025 | HEVO; CCC; Fusion Fuel; Vitol • 1 MW | starting date not documented | IRESEN; Fraunhofer IMWS • 3-5 MW | starting 2021 | OCP pilot in Jorf Lasfar • 100 MW | starting 2024 | MASEN with KfW	(IEA, 2022b), (Öko-Institut e.V., 2022)
Tunisia	None in the IEA Database 2022	• BMZ "Project Building blocks of green hydrogen in Tunisia" German KfW will finance pilots with 20 Mio. € • TuNur is planning a H_2 pilot project in the south of Tunisia	(IEA, 2022b), (Öko-Institut e.V., 2022)

2.5 Technology review: Ammonia synthesis

2.5.1 Technologies and Performance

The production of ammonia is an established industrial process. On an industrial scale, ammonia is produced via the Haber-Bosch (HB) synthesis process. For the synthesis of ammonia, hydrogen and nitrogen are required as feedstocks. Today's ammonia synthesis plants are typically supplied by on-site produced hydrogen via steam methane reforming (SMR) and on-site produced nitrogen via cryogenic air separation units (ASU).
While conventional ammonia production plants are based on technically and commercially mature technology, green ammonia production plants require further technological developments to improve the process flexibility when operated by variable energy supply from renewable energy sources.

2.5.2 Current Costs and Cost Projections

The specific CAPEX for ammonia synthesis plants are strongly dependent on the plant scale and range from 4,935 USD/tpa at 20 ktpa plant scale up to 1,860 USD/tpa at 650 ktpa plant scale according to (IRENA, 2022).

2.6 Technology review: Methanol synthesis

2.6.1 Technologies and Performance

Methanol production is a well-established industrial process. At industrial scale, methanol is produced from natural gas or coal. For the synthesis of green e-methanol, hydrogen and carbon dioxide are required as feedstocks. Today's methanol synthesis plants are typically supplied by syngas through natural gas reforming or coal gasification.

The chemical process of e-methanol production from renewable sources is identical to fossil-based methanol but can lower the GHG emissions during the entire lifecycle. To obtain renewable e-methanol with a CO_2 neutral footprint CO_2 from sustainable sources like biomass or direct air capture is required as feedstock.

2.6.2 Current Costs and Cost Projections

The specific CAPEX for methanol synthesis plants is dependent on the plant scale and range from 9,720 USD/tpa at 4,000 tpa plant scale up to 2,000 USD/tpa at 100 ktpa plant scale according to (IRENA, 2021b).

2.7 Summary of review

Substantial **renewable energy** potentials for CSP, PV and Wind exist in the targeted countries. Although the respective potentials differ among the countries, all the technologies are relevant candidates for Power-to-X processes and will be considered for the techno-economic analysis. The optimization exclusively considered onshore wind for the Wind component. In contrast, for Concentrated Solar Power (CSP), a comprehensive analysis was conducted, considering both solar tower and parabolic trough systems.

Current mature technologies in **water electrolysis** are AEL and PEM electrolysis. According to (IEA, 2022a) both AEL and PEM technology are considered as commercially available technologies with TRL 9. From a modelling perspective the difference between AEL and PEM is quite small when optimizing power-to-X value chains. Therefore only AEL, which is currently more competitive for large-scale applications is considered for modelling in this study. The SOEL, operating at high-temperature steam, is an emerging technology, which is at TRL 7[8]. SOEL is of particular interest in combination with CSP, as its thermal energy requirements may be met directly by CSP components.

While the **technologies for the production of hydrogen derivatives such as ammonia and methanol** are generally mature, their deployment in combination with volatile RES has not been proven on an industrial scale. The flexibility of these processes remains limited, especially for methanol synthesis, although improvements are expected as more renewable production capacities are being developed. Therefore, a steady supply of renewable electricity is a key for the viability of large-scale renewable hydrogen derivative production. This can be achieved to some extent by combining various mature RES technologies. According to the review, the highest capacity factors (CF) can be achieved with CSP (+ thermal storage).

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[8] TLR scale refers to the IEA definition for Electrolyzers from TRL 1 to TRL 11 scale. **Electrolyzers – Analysis – IEA**

3 Techno-economic Analysis

3.1 Task and Approach

The goal of the techno-economic analysis is to conclude on the competitiveness of CSP-PV hybrid power plants for the production of **green H_2, green ammonia and green methanol in the MENA region** using exemplary sites in **Algeria, Morocco, and Tunisia**. By analyzing multiple parameters, it is to be shown if and under which conditions the use of CSP-PV hybrid power plants have competitive advantages compared to other RE system configurations considering multiple Key Performance Indicators (KPIs) such as costs or environmental and social indicators. Various factors influencing the potential application of CSP-PV hybrid systems shall be examined and evaluated by performing a scenario analysis.

The composition of scenarios covers five sites with varying RE potentials, two different technology scenarios, three target products/commodities, and two-time horizons. The scenario definition is described in detail in section 3.4. This results in a total of 60 cases. The optimal system design and operational characteristics of the systems in all cases are then analysed and compared against each other. The KPIs are compared among scenarios benchmarked additionally against reference values. The comparative analysis allows conclusions to be drawn about the relevance of the various input factors/external conditions for the feasibility of CSP-PV hybrid PtX projects.

3.2 Modelling Methodology

The commercial modelling software tool PROSUMER was applied, which allows for detailed hourly modelling of all stages of hydrogen/ammonia/methanol production considering renewable power generation, electrolysis and all relevant stages of conversion, transport, and storage to desired end-products. It is a bottom-up technology driven approach using least cost optimisation technique for the identification and selection of the optimal system design as well as for optimal system operation. The modelling yields a techno-economic optimum for each scenario based on a mixed-integer linear programming (MILP) optimization algorithm.

Input factors are cost items (CAPEX and OPEX) and operational characteristics (e.g., min/max capacity, ramping rates, conversion efficiency, degradation, generation profiles of the renewable energy plants, etc.) by module/facility. The input data is partly based on section 2 and based partly on the consultant's project experience. For a comprehensive list of input assumptions see Appendix A: Assumptions book – Techno-economic parameters used for the optimization.

As a **result**, the PROSUMER model determines the optimal capacity of the assets (e.g., VRE generator capacities relative to the electrolyzer size and hydrogen/battery/thermal energy storage capacity) and the optimal asset operation (yearly and hourly dispatch) in order to achieve the lowest cost of hydrogen/ammonia/methanol production over the course of the facilities' lifetime (Total cost of ownership, TCO). As the yearly production amount is considered a given input per scenario, minimising the TCO is equivalent to minimising the levelized cost of PtX production (LCOX)

More details on the PROSUMER tool can be found in Appendix C: PROSUMER Tool description.

3.3 General Assumptions

The energy conversion technologies and processes are modelled in PROSUMER using the techno-economic parameters (Costs, conversion efficiencies, lifetime, etc.) detailed in Appendix A. These parameters are based on section 2 and on relevant project experience of the Consultant. Cost estimates for the 2030-time horizon are Class 3[9] estimates (+/- 20% to 30%), which are typically used during preliminary design or feasibility study phase. Spatial distribution of the energy system components plays a minor role in the modelling for this study, as project experience has shown that it can be flexibly adapted to specific project conditions, without major impacts on project economics/feasibility. E.g., co-location of VRE generation and PtX processes is assumed.

[9] Per AACE International (Association for the Advancement of Cost Engineering) Recommended Practice No. 18R 97

The Cost for pipeline transport of desalinated water to inland locations is quite low compared to VRE assets and electrolyzer costs. Therefore, water/CO_2 transport costs are only included in the levelized cost of production calculation after optimisation. The by-products of the PtX value chain (e.g., waste heat, oxygen from electrolysis, oxygen and argon from air separation) and their sale are not considered in optimization. Marine shipping facilities and related infrastructure are also not included in the model.

The data is analysed and compared in a data verification process to ensure data accuracy. Reference values from published projects and publications have been used. Additionally, consultants' experiences is used for verification.

Regarding the local policy/legal framework, no difference among sites/target countries are considered, as no national policies with significant impact on PtX projects (e.g., subsidy schemes) are known in the target countries. In this context, it is important to note that the EU regulation on renewable fuels of non-biological origin (RFNBOs), which includes green hydrogen, green ammonia and green methanol, requires that the electricity generation installation must not have received any subsidies in the form of operating or investment aid (European Commission, 2023, Article 5b) This is taken into account in the modelling by not allowing and thus not considering the use of grid electricity.

3.4 Scenario Definition

To cover a broad scope of possible framework conditions of PtX projects, a comprehensive multi-dimension scenario analysis is performed. The following graph gives an overview of the dimensions and the respective manifestations considered. Recombination of the scenarios results in a total of 60 distinct cases. More details follow in the sub-chapters of this section.

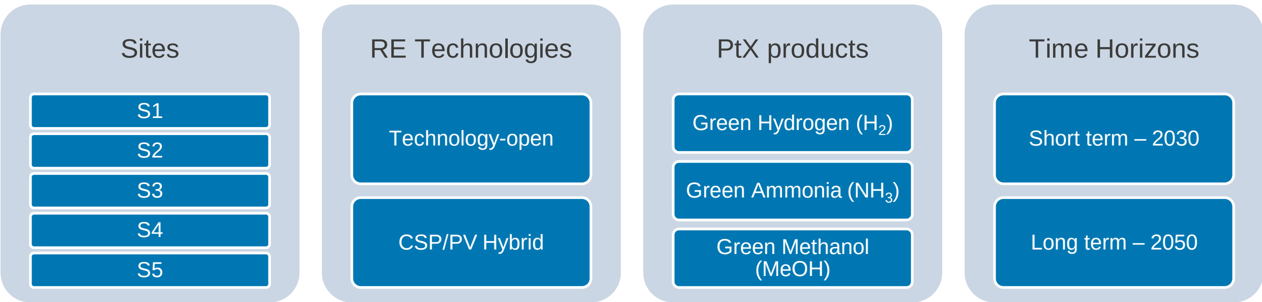

Figure 1: Scenario dimensions and respective alternative manifestations

3.4.1 Sites (local resources)

For the scenario analysis, five locations will be considered, at least one per country. The sites will be selected on the basis of previous studies and literature, which have considered – among others – following criteria for identification of potential sites for CSP/PtX projects:

- Above-average renewable energy potentials and consequently lower H_2 levelized costs study based on preceding studies.
- Infrastructure availability such as grid, roads, or pipelines,
- Exclusion of protected areas, areas for agricultural, water and permanent ice areas or forests

A preliminary screening of solar and wind resources using publicly available data, ensured that there are high levels of resource availability, yet some variation among the considered sites. This means to ensure the avoidance of methodological bias that could favour certain technologies over others.

Figure 2 shows the selected sites based on the the PtX Atlas (Fraunhofer IEE, 2022) and Table 16 summarizes the characteristics for each site. At this place, it should be pointed out, that theses 5 sites serve as representative sites for different RE conditions. This means that in case of similar RE conditions at other sites and countries the modelling results could also apply for these sites. No further national conditions, especially legal conditions and hydrogen standards were taken into account for the site selection.

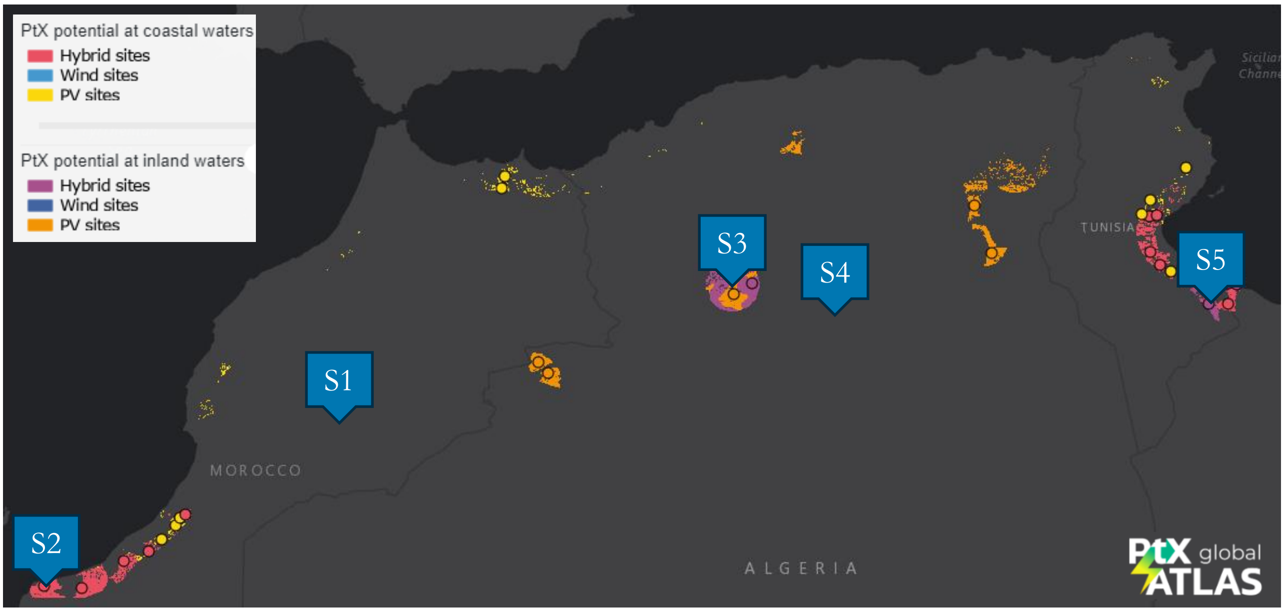

Figure 2: Selected sites, shown on the PtX Atlas (Fraunhofer IEE, 2022), Global PtX Atlas | Fraunhofer IEE

Sites S2, S3 and S5 represent an overlap of potential hybrid sites, which was identified by the PtX Atlas (Fraunhofer IEE, 2022) focusing on Wind and PV as RE technologies, and by the studies (Dii, 2012), (Dii, 2013), which examined potential CSP (hybrid) locations. S1 was selected as it is the site of one of the largest existing CSP plants to date and represents the best case regarding solar resources. S4 was selected for its potential role as a green hydrogen transit hub, due to its existing infrastructure for the export of (natural) gas to Europe (Prepublished National Hydrogen strategy).

Table 12: Sites selection

Site	Location	Country	Coordinates	Description
S1	Ouarzazate	Morocco	31.0863, -6.8729	In-country, Very high PV/CSP Low Wind
S2	Laâyoune	Morocco	27.6994, -13.0407	Coastal, Moderate PV, Low CSP Very high Wind
S3	El-Bayadh	Algeria	33.5952, 1.0238	In-country, High PV/CSP Moderate Wind
S4	Hassi R'Mel	Algeria	32.8985, 3.2983	In-country, High PV/CSP Moderate Wind v
S5	Tataouine	Tunisia	32.9087, 10.2508	In-country, Moderate PV, Low CSP Moderate Wind

Based in this site selection, public and commercial meteorological datasets and simulation tools were used to determine the VRE resources availabilities per site (8760h profile for wind, PV, CSP), which serve as input to the techno-economic modelling. More details on this are provided in Appendix A.

3.4.2 Technologies and System Selection

The applied methodology of least-cost optimization allows selecting the most economic combination of technologies to be selected from a large pool of candidate technologies. This approach eliminates the need to predefine acceptable technology combinations. By giving the optimization model the freedom to make choices independently, it minimizes the impact of the modeler's personal biases and leads to the discovery of economically optimized solutions. However, to be able to fulfil the objective of the techno-economic analysis to assess the competitiveness of CSP-PV hybrid based PtX projects (Section 3.1), it is necessary to compare CSP-PV hybrid systems against other system compositions such as Wind/PV hybrid, even in cases where CSP would not be selected by a technology-agnostic least-cost optimization.

Therefore, the two following RE technology scenarios are introduced:

In the **RE technology open system,** all renewable energy technology candidate, i.e., CSP, PV, Wind together with battery storage, hydrogen storage or thermal energy storage are considered (see Figure 3Figure 3).

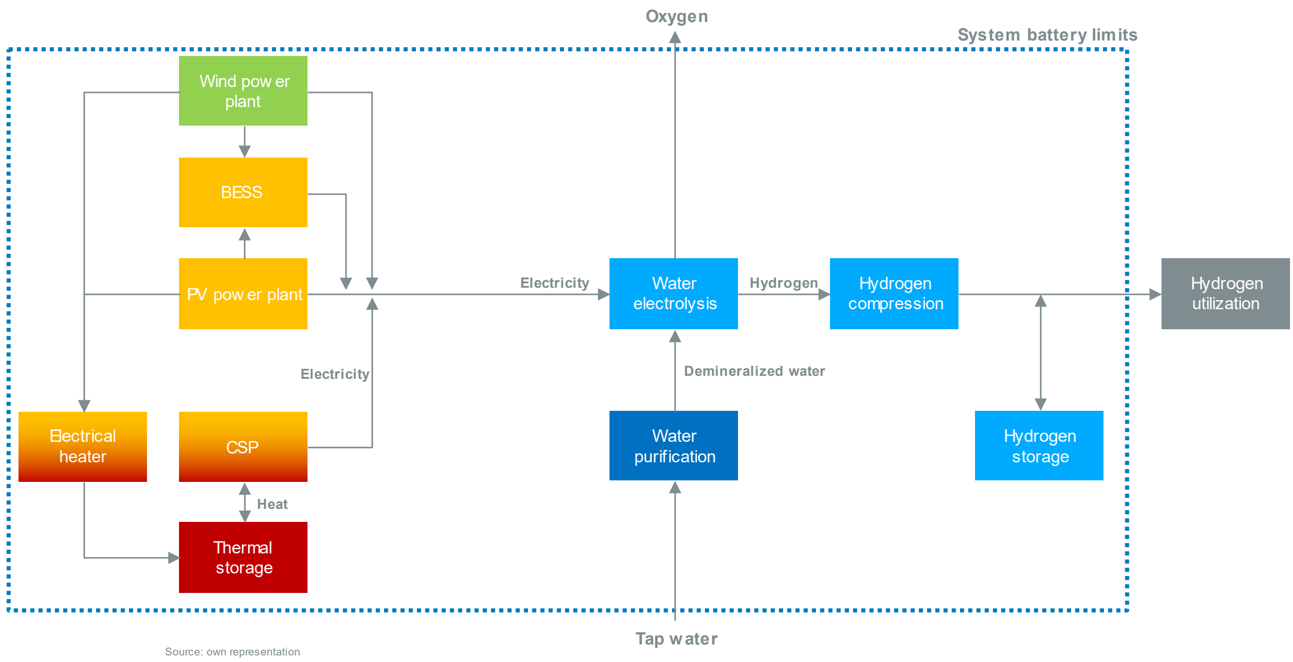

Figure 3: Technology open scenario, own illustration

For the **CSP/PV hybrid system the general assumptions are the same as for the technology open scenario** (see Figure 4). However, this scenario focuses on selected CSP technologies with solar PV for electricity production without considering other renewable systems. I.e., Wind turbines are not considered as candidate technology.

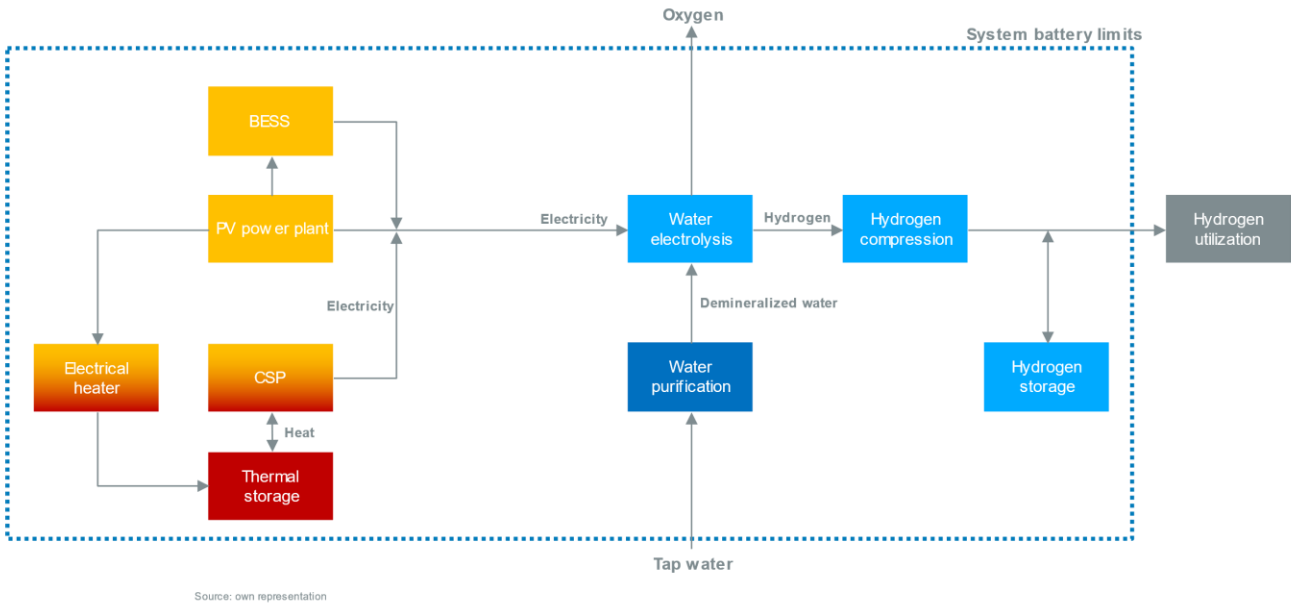

Figure 4: CSP/PV hybrid technology scenario, own illustration

3.4.3 PtX products

The scenario analysis covers three different PtX products, namely **green hydrogen (H_2)**, **green ammonia (NH_3)**, and **green methanol (MeOH)**. While green hydrogen is a direct product of electrolysis using renewable energy, green ammonia and green methanol are so-called hydrogen derivatives, i.e., they require green hydrogen as the main input for another conversion process.

Direct use of green hydrogen may come into consideration if there are domestic/regional demands, e.g., from steel industry, or if it can be directly exported via pipelines, if such infrastructure exists or can be economically built/retrofitted. Derivatives, on the other hand, are much easier to transport and can be exported via ship, e.g., to replace fossil-based chemicals in importing economies, to achieve carbon emission reductions.

This study, however, focusses on the value chain up to the production of PtX products. Three scenarios will be considered, one each for the three PtX products mentioned above.

To allow for comparability between the scenarios, **all PtX product scenarios** assume:

- An electrolyzer output capacity of 3.9 t H_2/h, corresponding to ~200 MW_{el} in case of AEL electrolysis and 161 MW_{el} in case of SOEL electrolysis.
- A target capacity factor of the electrolyzer of 60%/5,256 FLH. This is a average value for Green H_2 projects.
- This output capacity and capacity factor result in a **target for annual production of ~20.5 kt H_2**.

At this place, it should be pointed out, that this fix assumption regarding the electrolyser output capacity in combination with a pre-defined capacity factor (CF), removes some freedom in optimisation, especially in regard to cost optimisation. The influence of higher CF in combination with lower capacity output was not evaluated. However, the assumed assumption are based on the consultant's experience of dynamic cost optimisation and are typical value for Green hydrogen projects currently in development in the MENA region.

Even for the derivatives ammonia and methanol, electrolysis remains the core of the Power-to-X value chain in terms of energy needs and costs. As this study focusses on supply alternatives for renewable energy, only the hydrogen production and storage are explicitly modelled for the techno-economic analysis. However, by considering the respective **minimum H_2**

supply levels for each target commodity's production process, a differentiation between different PtX products is implicitly considered:

- Hydrogen as final product/**H_2**
  - No restrictions on minimum H_2 supply level is considered, i.e. f**ull flexibility of hydrogen supply**.[10]
- Ammonia as final product/**NH_3**
  - The fixed H_2 production target of **~20.5 kt H_2** p.a. and the specific H_2 demand for ammonia production of 0.18 kg H_2/kg NH_3 yields annual NH_3 production target of 113.9 kt NH_3
  - To reach a typical capacity factor of 80% for an ammonia synthesis plant, a capacity of 16.25 t NH_3/h is needed.
  - This plant capacity and the technology specific minimum turn ratio of **20%** results in a min production of 2.6 t NH_3/h, corresponding to **minimum H_2 supply of 0.585 t H_2/h.**
  - This corresponds to 15% loading of the electrolyzer but may also be (partly) met from H_2 storage.
- Methanol as final product/**MeOH**
  - The fixed H_2 production target of **~20.5 kt H_2** p.a. and the specific H_2 demand for methanol production of 0.19 kg H_2/kg MeOH yields annual MeOH production target of 107.9 kt MeOH
  - To reach a typical capacity factor of 80% for a methanol synthesis plant, a capacity of 12.48 t MeOH/h is needed.
  - This plant capacity and the technology specific minimum turn ratio of **80%** results in a min. production of 8.87 t MeOH/h, corresponding to **minimum H_2 supply of 2.340 t H_2/h.**
  - This corresponds to 60% loading of the electrolyzer but may also be (partly) met from H_2 storage.

The minimum turndown ratio of the electrolyzer plant (1% for AEL or 30% for SOEL) are respected in the hourly modelling for all PtX products. It should be noted that opposed to NH_3 and MeOH synthesis processes, the electrolysis can also be put on standby/shut down.

Seasonal variations in H_2/derivatives output during the year are allowed. This enables the model to optimize the timing of production, i.e., to adapt production to match the seasonal availability of electricity from RES. This reduces RES capacity needs and/or storage needs relative to annual production.

3.4.4 Time horizons

The literature review has shown that the costs of the energy conversion technologies considered in this analysis are expected to evolve differently in the future.

In order to assess a potential economics-driven technology shift, the scenario analysis considers two pivotal years or horizons:

- As a baseline, a commissioning year (COD) of **2030** is considered. This is a realistic COD for PtX projects that enter the initial stage of project development (scoping) in after the release of this report (October 2023). All cost assumptions found in Appendix A refer to this baseline case.
- To explore **future** developments, a COD of **2050** is considered. For this assumption, following CAPEX decreases are assumed:
  - CSP -7% (is applied to all CSP components: Solar field, Power block, TES)
  - PV -31%
  - Wind -23%
  - AEL -27%
  - SOEL -79%
  - BESS -25%

[10] This assumption offers a contrast to the baseload supply requirements defined in the NH_3 and MeOH scenarios. It should be noted that it is not applicable for all projects with hydrogen as final product. It is most applicable for projects integrated in broader energy systems, e.g., if the production facility is connected to a higher-level pipeline infrastructure, if it is complemented by conventional hydrogen production or if the hydrogen is blended with natural gas.

PV and solid-oxide electrolysis (SOEL) are expected to see the most significant cost reduction. Costs for CSP or alkaline electrolysis (AEL) are expected to decrease by a smaller percentage.

Based on RES costs alone, a smaller role for CSP in the future seems likely. However, an almost 80% cost decrease of SOEL electrolysis, which requires thermal energy for H_2 production, may create new use cases for CSP, as it can provide thermal energy directly at low costs.

It should be noted that the 2050 scenario only considers the expected CAPEX reduction of key components. All other parameters (e.g., conversion efficiencies) are assumed to remain as in 2030. In the context of this study, it serves as a "what-if" analysis, rather than claiming to be an accurate prediction of future developments.
Therefore, its results should be interpreted by comparison with the 2030 results, rather than external references for future PtX project performance.

3.5 Key Performance Indicators (KPIs)

Following KPIs are used to evaluate and compare the optimized renewable PtX project setups per scenario:

Table 13: Key Performance Indicators (KPIs)

Category	Specification of KPI
Economic	Capital Expenditure (CAPEX) in USD
	Operational Expenditure (OPEX) in USD
	Levelized costs of PtX Production (LCOX) in USD/kg
Ecology	Water demand pro production unit of PtX, in l/kg
	Land use pro production unit, in m³/kg
Social	Number of employees, in jobs/kg

The **CAPEX** and **OPEX** refer to the sum expenses over the whole project period (net present value, i.e., discounted) and are calculated based on the optimization results (asset sizing and operation) and the assumptions given in Appendix A.

The Levelized production costs of respective PtX commodities (**LCOX**) are calculated for hydrogen (LCOH) and – if applicable for the respective scenario – for ammonia (LCOA) or methanol (LCOM). LCOX is defined as:

$$LCOX = \frac{TCO_X}{Total\ Production\ of\ X}$$

Where TCO_X is the discounted total cost of ownership for commodity X. It includes CAPEX and OPEX for all components required to produce and supply this commodity and $Total\ Production\ of\ X$ refers to the produced amount of this commodity during the project period, discounted with the same discount rate as the TCO. The composition of LCOX calculation for ammonia is presented in Figure 5.

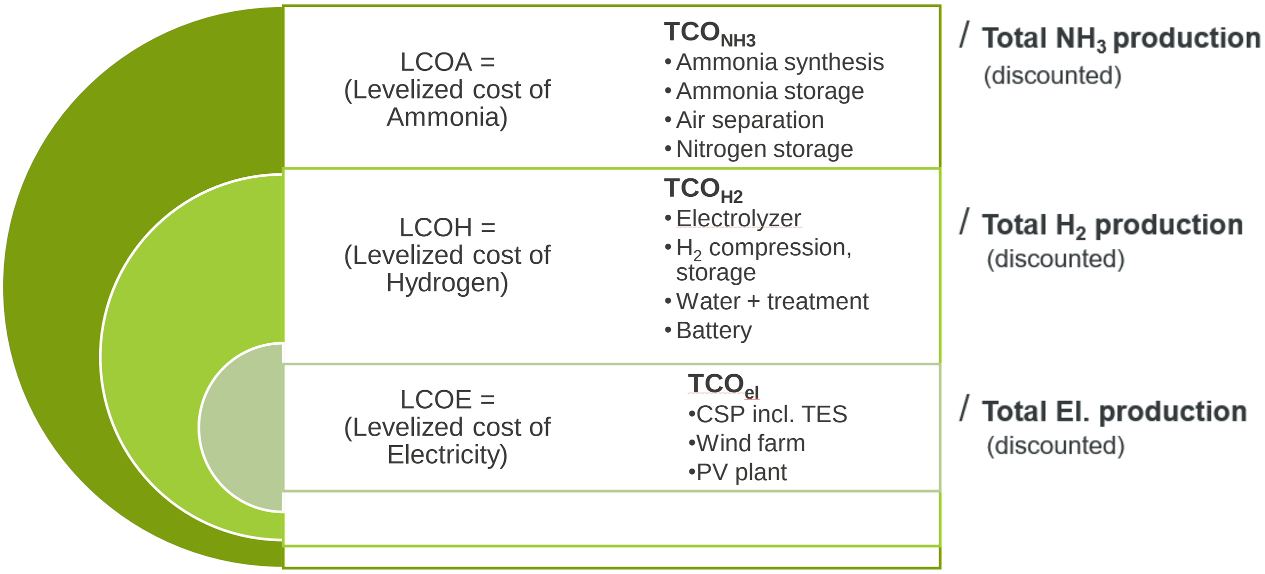

Figure 5: Composition of Levelized cost of Ammonia (LCOA)

(Note that the TCO for electricity production is part of TCO for hydrogen production, which is in turn part of TCO for production of ammonia.)

The social and ecological KPIs are evaluated based on the optimization outputs using the key technology specific parameters for employment, land requirements and water consumption.

Table 14: Socio-economic & environmental parameters

(Note: these figures are presented in more detail in the Appendix B including references. Where min/max ranges have been indicated in the literature review, median values are used for the KPI evaluation.)

Technology	Employment [jobs/MW]	Land requirements [ha/MW]	Water consumption
CSP	13	2	0.3 m^3/MWh_{el}[11]
Wind	5.9	3.1	
PV (fixed tilt)	3.5	1.1	
Electrolysis (AEL | SOEL)	4.75[12]	0.02	9.3 | 11.1 $m^3/t\ H_2$[13]

It should be noted that these parameters (assumptions) are not used as inputs for the optimization of PtX value chains but are used to estimate the socio-economic and environmental impacts of the examined PtX projects based on the outcome of an economics-driven optimization. For the evaluation of environmental and social KPIs, the PtX value chain is only evaluated

[11] Mainly make-up water consumption of steam cycle. Assumes air-cooled condenser.
[12] Excluding jobs created from renewable energy installations. In addition, a regional employment multiplier for the MENA region of 1.51 in 2030 and 1.23 in 2050 based on assumptions on labour productivity is considered.
[13] Based on water requirements listed in section 3.3.

up to the production of hydrogen, which is the common core of all PtX value chains considered in this study. The synthesis of derivatives (e.g., water demand of Haber-Bosch process) is not considered to allow for better comparability of the results among different PtX cases.

3.6 Limitations of this study and future work

The purpose of this section is to show the constraints and shortcomings of the study, while maintaining the integrity and transparency of the work.

Reliability and validity of input data sources and data processing

It should be noted that the literature review presented in section 2 of this study only gives a high-level review of technologies considered in this study. Within this project scope, it was not possible to conduct comprehensive local data collection and review e.g., organising interviews with local experts or stakeholders. However, the Consultant's expertise from multiple previous projects have been used to secure the data quality assurance. By this, Class 3[14] estimates (+/- 20% to 30%), which are typically used during preliminary design or feasibility study phase are achieved. For confidentiality reasons, detailed documentation of data from previous projects could not be included in this report. However, a high-level review of the assumptions with independent experts was conducted.

Applied methodology limitations

The techno-economic analysis is based on a common mixed-integer linear optimization methodology to optimize multiple scenarios (refer to: Appendix C). The main limitation of this approach is its inherent restriction to linear constraints and objective functions, which may not adequately address the complexity of the nonlinear relationships and limitations frequently encountered in real-world techno-economic systems. Furthermore, the applied optimization methodology relies on deterministic input values. Uncertainties (e.g. regarding cost estimates or VRE availability) can therefore not be fully accounted for.

[14] Per AACE International (Association for the Advancement of Cost Engineering) Recommended Practice No. 18R 97

4 Key modelling results

4.1 Volatile Renewable Energy (VRE)

The availability of REs at each site is the only factor influencing the choice of technology and thus the LCOX in this modelling approach. Therefore, the later results should always be linked to this evaluation as they are essential for the interpretation of the results.

The following graphs give an overview of the respective VRE resource availabilities per site and show the distribution of the hourly capacity factors during one year for each VRE technology in a box plot. The respective 8760 h timeseries of hourly capacity factors is determined using meteorological data and technology-specific simulations and are an input to the techno-economic modelling.

Figure 6 shows that,

- site **S1** represents very high PV and CSP resources (high yearly average capacity factor) and low wind resources.
- at the coastal site **S2** the conditions are completely different. While PV resources are moderate, and CSP even lower, wind has an exceptionally high availability,
- site **S5** has similar conditions as **S2** for PV and CSP but with a lower-capacity factor for wind
- site **S3** and **S4** have similar conditions with high PV and CSP conditions combined with moderate wind conditions.

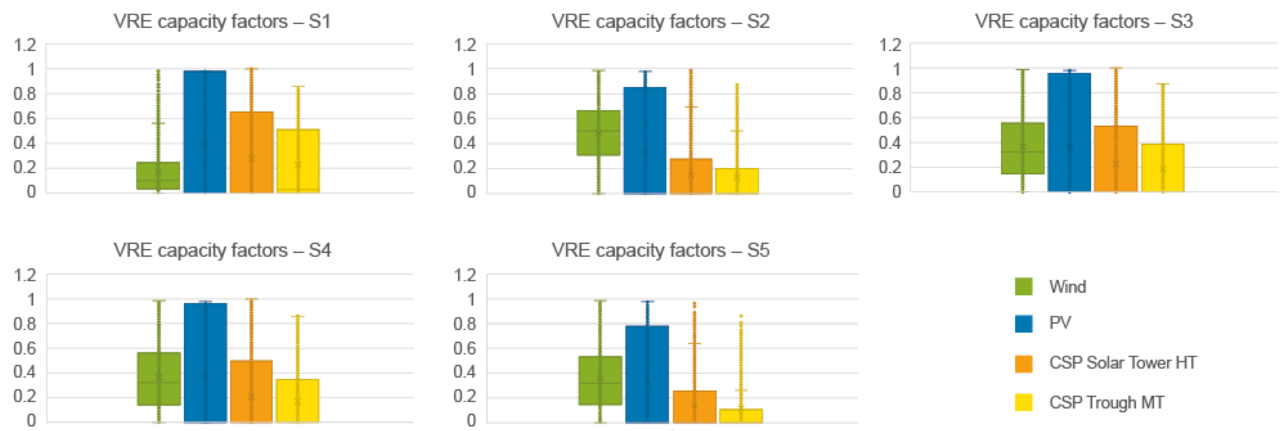

Figure 6: Volatile Renewable Energy (VRE)

(Note that the capacity factors of CSP Solar Tower/Trough shown here do not refer to electrical output of a CSP plant (which is dependent on TES sizing and other design factors). Instead, it represents the capacity factor of the thermal energy output of the solar field.)

4.2 Optimal energy mix for all scenarios

In this section the technology mix for each of the 60 scenarios will be presented and discussed

The results are divided into two parts:

1. Energy mix of Wind, PV and CSP (GWh). Note: The different results among the sites are driven by the assumed local VRE resources, no other site-specific conditions, like infrastructure, was considered
2. The capacity factor of the chosen RES technologies in combination with the selected storage option (Battery storage vs. electrical heater combined with thermal storage). Note: the electrolysis output capacity and its capacity factor were fixed for this model approach. Thus, for all cases, a target production of 20.5 kt H_2 per year is assumed with varying requirements on minimum hourly hydrogen supply (see: section 3.4.3).

Figure 7 shows the mix of energy sources selected by the optimization for all three products and for all five locations for the technology-open scenario for 2030: The following can be summarized:

- For all scenarios:
    - Solar tower system is preferred over parabolic through systems (applies to all 60 cases) This can be explained by the former's higher capacity factor (of heat generation) and the higher heat-to-power conversion efficiency achieved by the higher temperature solar tower system.
    - AEL was chosen instead of SOEL due to the high CAPEX cost for SOEL in 2030
    - For MeOH production a higher share of curtailment (th. and el.) occurs, due to the oversizing of the RES systems, required to ensure the high baseload H2 supply for the synthesis process (80% min turndown ratio).
- S1: The optimization selects for S1 a CSP-PV hybrid system for all three products due to the very high PV and CSP resources. Wind is not selected at all, as the low-capacity factor makes it uneconomic compared to PV and CSP at this site.
- S2 + S5. The optimization selects for S2 and S5 wind as the main energy source for all three products, due to the high wind conditions. However specially to produce MeOH and the required baseload, PV is used as a supplementary source. For S5, there is also a certain size of PV for all three products due to the lower wind conditions in comparison to S2.
- S3 + S4: For green H_2 and green NH_3, a PV-wind hybrid system was selected by the optimisation due to moderate wind conditions whereby for green MeOH production a mix of all three energy sources (PV, CSP and wind) was selected due to the baseload required storage.

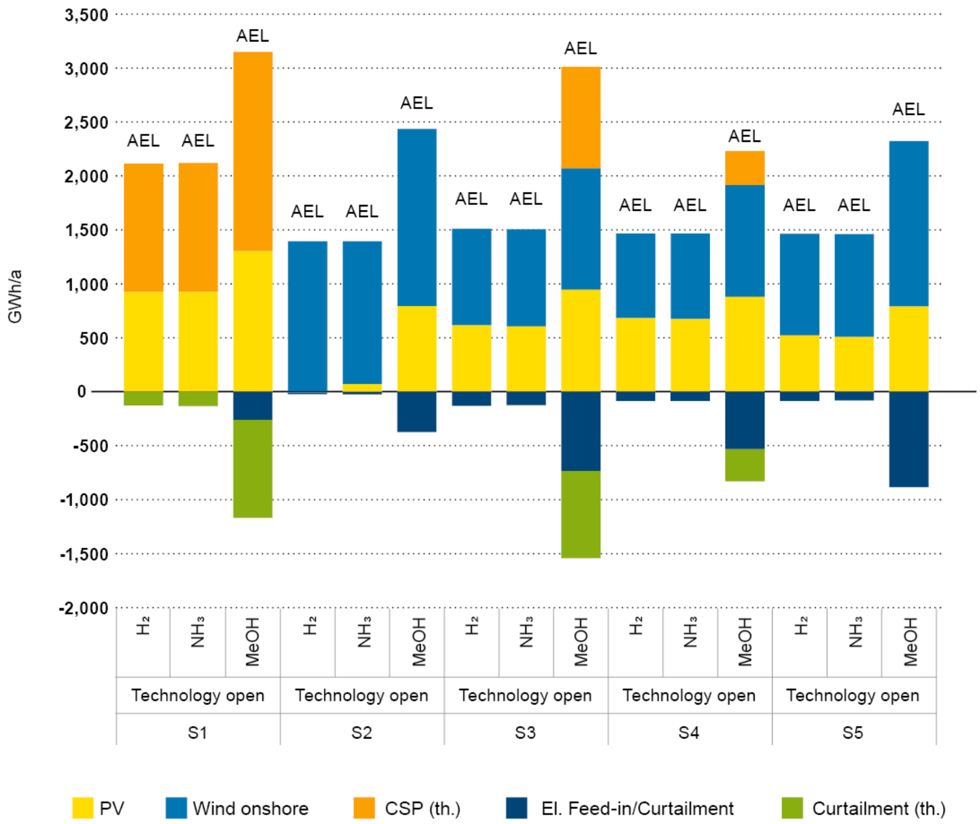

Figure 7: RE Energy inputs [GWh/a] for the technology-open scenario, for 2030

(Note: the bars in the positive section represent energy inputs. PV and Wind is counted as electrical energy (AC), input from CSP is measured as thermal energy generated by the CSP system may also be used as a direct input into the electrolysis process, i.e. not be converted to electrical energy at all. However, when comparing thermal energy input with electrical energy, the heat-to-power conversion efficiency of 35-43 % in CSP systems should be kept in mind. Negative values in the graph denote excess renewable energy, that is either fed into the public grid systems with CSP, curtailment of thermal energy occurs, i.e., if there is an oversupply of solar energy due to system or curtailed. In constraints, solar input is curtailed by reducing the amount of sunlight directed to the solar collector.)

Figure 8 shows the mix of energy sources selected by the optimization for all three products and for all five locations for the CSP-PV hybrid scenario for 2030: Compared to the technology open scenario, the following can be summarised.

- For all scenarios:
  - Generally, the energy inputs for the CSP-PV hybrid system are higher than for the technology-open scenario. This is related to a) higher curtailments due to required oversizing of PV and CSP, and b) losses from to heat-to-power conversion of CSP.
  - As in the technology-open scenario, the curtailment for green MeOH is higher than for H_2 and NH_3 due to the baseload required for the synthesis process.
  - For the MeOH production for four if the five sites, SOEL was selected instead of AEL (S2-S5) to SOELs partial reliance on thermal energy as an input, which can be stored at lower costs than electricity, leading to better economics for the high baseload requirements of the MeOH scenarios.
- S1: As a CSP-PV hybrid combination has already been selected in the technology-open scenario, there are no differences here.
- S2 + S5: Where CSP was not selected in the technology-open scenario, in the CSP-PV hybrid scenario, CSP was not selected at all or only at a very low capacity, so that the up to 100% of the energy input comes from PV due to the low CSP conditions at these sites.
- S3 + S4: Where CSP was only selected for MeOH production in the technology-open scenario, in this target scenario a combination of CSP and PV was selected for all three products, thus CSP will be a supplementary source to the PV production (in case of wind power not being feasible)

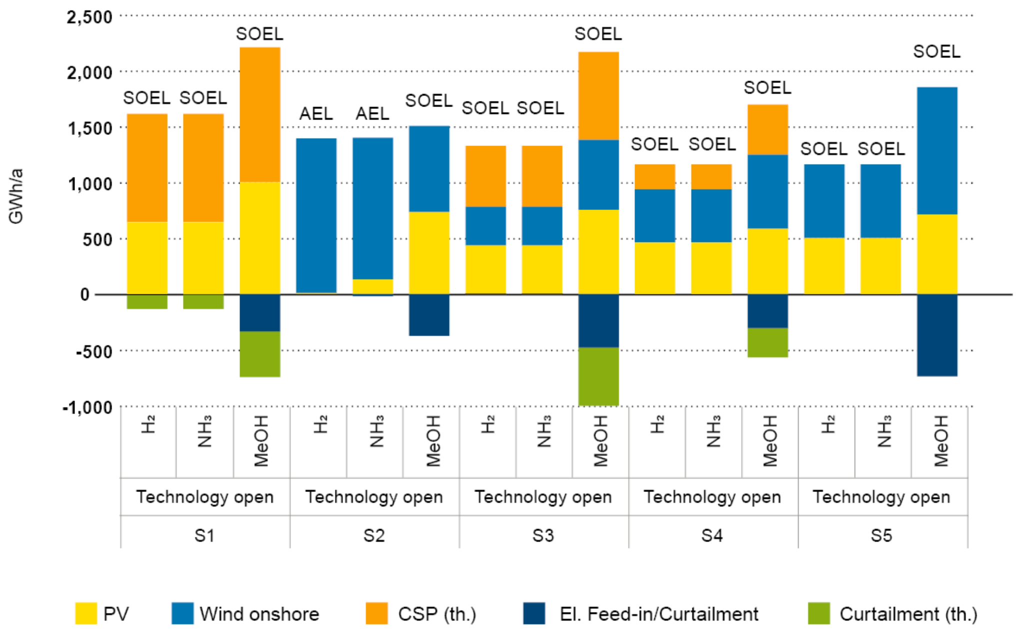

Figure 8: RE Energy inputs [GWh/a] for the CSP-PV hybrid scenario, for 2030

(Note: the bars in the positive section represent energy inputs. PV and Wind is counted as electrical energy (AC), input from CSP is measured as thermal energy generated by the CSP system may also be used as a direct input into the electrolysis process, i.e. not be converted to electrical energy at all. However, when comparing thermal energy input with electrical energy, the heat-to-power conversion efficiency of 35-43 % in CSP systems should be kept in mind. Negative values in the graph denote excess renewable energy, that is either fed into the public grid systems with CSP, curtailment of thermal energy occurs, i.e., if there is an oversupply of solar energy due to system or curtailed. In constraints, solar input is curtailed by reducing the amount of sunlight directed to the solar collector.)

Figure 9 shows the mix of energy sources selected by the optimization for all three products and for all five locations for both scenarios for 2050: The following can be summarized in comparison to 2030:

- For all scenarios:
  - Generally, the amounts of energy input are lower in 2050 for both scenarios (technology open and CSP-PV hybrid scenario) due to reduced curtailment or feed-in, which is enabled by the 25% lower costs of BESS.

  - SOEL is the preferred electrolysis technology due to the estimated cost estimation in 2050. Only in case of a high share of energy supply by wind, AEL is still the preferred choice by the optimization system due to the lower availability solar resources on those sites, making the use of thermal energy form CSP less attractive.
- S2 + S5: For the technology open scenario, a PV-wind combination is still the preferred design. In case of wind power not being feasible (CSP-PV hybrid scenario) the preferred system design consists only of PV as the main energy source and CSP is not selected at all. Where in 2030 a small share of CSP was selected by the system in 2050 CSP is not chosen by the model anymore due to the smaller anticipated cost reduction of CSP compared to other VRE technologies
- S3 + S4: CSP is still selected for energy input in the technology open scenario for all three products. However, the share is reduced in comparison to 2030. This can be explained by the smaller cost reduction of CSP compared to PV. In contrast for the technology open scenario for 2050 for all three products a mix of CSP, PV and wind was selected where in 2030 CSP was only selected for MeOH production. This can be explained by the switch from AEL to SOEL electrolyzer technology related to the latters steep cost reduction. Due to SOELs partial reliance on thermal energy as an input, which can be stored at lower costs than electricity, CSP which can directly provide thermal energy becomes more valuable to the system.

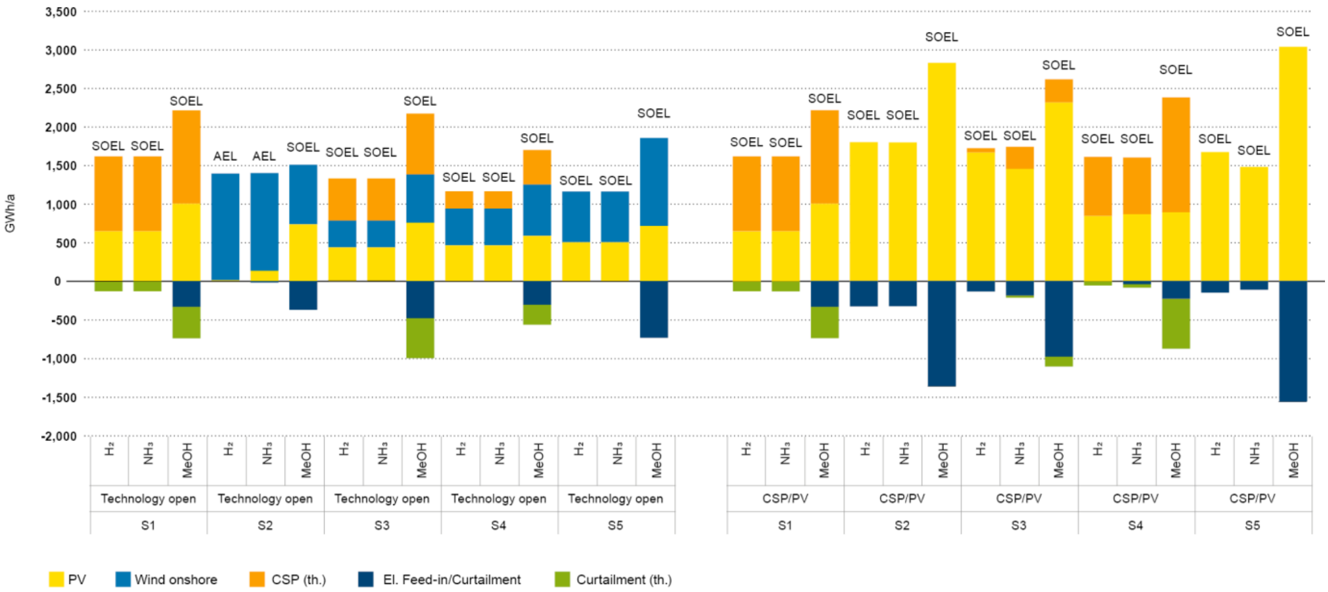

Figure 9: RE Energy inputs [GWh/a] for the technology open scenario (left) and the CSP-PV hybrid scenario (right) for 2050

(Note: the bars in the positive section represent energy inputs. PV and Wind is counted as electrical energy (AC), input from CSP is measured as thermal energy generated by the CSP system may also be used as a direct input into the electrolysis process, i.e. not be converted to electrical energy at all. However, when comparing thermal energy input with electrical energy, the heat-to-power conversion efficiency of 35-43 % in CSP systems should be kept in mind. Negative values in the graph denote excess renewable energy, that is either fed into the public grid systems with CSP, curtailment of thermal energy occurs, i.e., if there is an oversupply of solar energy due to system or curtailed. In constraints, solar input is curtailed by reducing the amount of sunlight directed to the solar collector.)

Table 15 shows the capacity factors (PV, wind, CSP) and the selected storage option selected by the optimization for all three products and for all five locations for the technology-open scenario for 2030: The following can be summarized:

- For all scenarios:
  - PV capacity factors are between 30-40% and thus in the expected range of PV systems. S2 with very high solar conditions reaches the highest CF with 39.3% for all scenarios. Further, there are no difference between the CF for the three products for each site site as electricity feed-in to the grid (equivalent to curtailment) is not considered in the CF.
  - The same can be recognized for wind CF factor, with the highest value for S2. Also, CF wind stays constant for all three products at each site.

  - Battery storage, this a electrical storage option is only selected in case of H_2 and NH_3 production and where CSP was not selected as energy source, so where wind energy is a main energy source (S2-S5). This can be explained by the high cost of BESS compared to TES, so that BESS is not selected if CSP + TES can also cover the system's storage needs.
  - For MeOH production for all sites a thermal storage option was selected by the optimization systems, meaning thermal storage is more economic than electric storage by batteries. So CSP components such as thermal storage with electrical heater (except MeOH production for S3) and a power block are included, even no solar collector is selected (no thermal energy input from CSP). This means that for high storage needs, even the high conversion losses of a power-to-heat-to-power storage can be outweighed by the low CAPEX of thermal energy storage.
- S1: CSP was selected in combination with PV as main energy source. The CF for CSP is for H_2 and NH_3 production around 24%, where for MeOH production CF decreases. This can be explained by the oversizing of the system due to the required baseload for the synthesis process. It should be noted that excess thermal energy cannot be feed into a public grid, so that curtailment of thermal energy is considered in the CF, as opposed to excess electricity from PV or wind.
- S3 + S4: Here, CSP was only selected for MeOH production and here as well the CF is much lower than the theoretical potential (1-3%) due to the high level of curtailment.

Table 15: RES capacity (MW) and the capacity factor (%) of the chosen RES technologies in combination with the selected storage option* for the technology open scenario for 2030

		S1			S2			S3			S4			S5		
		Technology open scenario, 2030														
		H_2	NH_3	MeOH	H_2	NH_3	MeOH	H_2	NH_3	MeOH	H_2	NH_3	MeOH	H_2	NH_3	MeOH
PV	MWAC	269	269	378	2	25	269	191	188	294	217	215	280	184	179	278
Wind	MW	0	0	0	334	318	395	302	304	380	273	275	360	321	325	522
CSP	MWth	487	481	758						468			170			
CF PV (%)		39.3%	39.3%	39.3%	33.7%	33.7%	33.7%	36.8%	36.8%	36.8%	35.8%	35.8%	35.8%	32.5%	32.5%	32.5%
CF Wind (%)					47.4%	47.4%	47.4%	33.8%	33.8%	33.8%	32.8%	32.8%	32.8%	33.5%	33.5%	33.5%
CF CSP (%)		24.7%	24.6%	14.2%						3.2%			1.2%			
CSP TES		x	x	x			x			x			x			x
Power block		x	x	x			x			x			x			x
Electric Heater				x			x						x			x
Battery storage					x	x		x	x		x	x		x	x	

Table 16: RES capacity (MW) and the capacity factor (%) of the chosen RES technologies in combination with the selected storage option* for the CSP-PV hybrid scenario for 2030

		S1			S2			S3			S4			S5		
		CSP-PV hybrid scneario, 2030														
		H_2	NH_3	MeOH	H_2	NH_3	MeOH	H_2	NH_3	MeOH	H_2	NH_3	MeOH	H_2	NH_3	MeOH
PV	MWAC	269	269	379	687	660	904	316	316	497	301	301	205	670	667	1108
CSP	MWth	486	490	788	0	74	0	574	570	534	663	668	950	148	165	0
CF PV (%)		39.3%	39.3%	39.3%	39.3%	33.7%	33.7%	33.7%	36.8%	36.8%	36.8%	35.8%	35.8%	35.8%	32.5%	32.5%
CF CSP (%)		24.7%	24.7%	24.6%	14.2%		13.6%		20.2%	20.6%	12.9%	19.3%	19.6%	11.4%	13.3%	13.1%
CSP TES		x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Power block		x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Electric Heater					x	x	x	x	x	x	x	x	x	x	x	x
Battery storage								x								

*Battery storage vs. electrical heater combined with thermal storage

Comparing these results with the results for the CSP-PV hybrid scenario for 2030 (see Table 16), the following can be observed:

- The capacity factor for PV remains the same for all products for all sites compared to the technology open scenario.
- In case CSP was selected, CSP reached a capacity factor between 20-24% for H_2 and NH_3 production in S1, S3, S5 and between 11-14% for MeOH production in S2 and S4. Thus, for the later cases the scenario factor is much higher than in the technology open scenario indicating that CSP has a role in providing an additional energy input rather than being used for backup electricity supply via thermal storage.
- For all cases thermal storage (including thermal storage, CSP power block and electrical heater) is the most economical storage option even if CSP was not selected as energy source. This means that for high storage needs, even the high conversion losses of a power-to-heat-to-power storage can be outweighed by the low CAPEX of thermal energy storage.
- Only for S1, an electrical heater was not selected by the optimization model. This can be explained by the site specific higher capacity factor of the CSP plant, making it more competitive with the combination of PV + electrical heater for charging the thermal storage.

Note: The comparison of the results for 2030 with the results for 2050 for both scenarios does not show any further characteristics in the composition of the energy sources, the CF and the storage option that could not already be observed in the analysis of the results for 2030.

4.3 Optimized system design – example: Site S4

In this section, the optimization results are shown at a higher level of detail, i.e., the exact system configuration and the material and energy flows based on a Sankey diagram. Due to the large number of scenarios examined, only selected scenarios are described in detail here. The selected scenarios are chosen in such a way, that they are representative, i.e., many of the various dynamics of the optimization observed over all 60 cases are shown. Note that the fully detailed modelling results including installed capacity of each system component, yearly commodity consumption/production amounts per component, capacity factors, etc. for all sites/scenarios are found in Appendix D: Detailed site-specific results.

For the following optimal system design analysis, scenarios of site 4 were chosen.

4.3.1 S4: technology-open scenario, NH_3, 2030

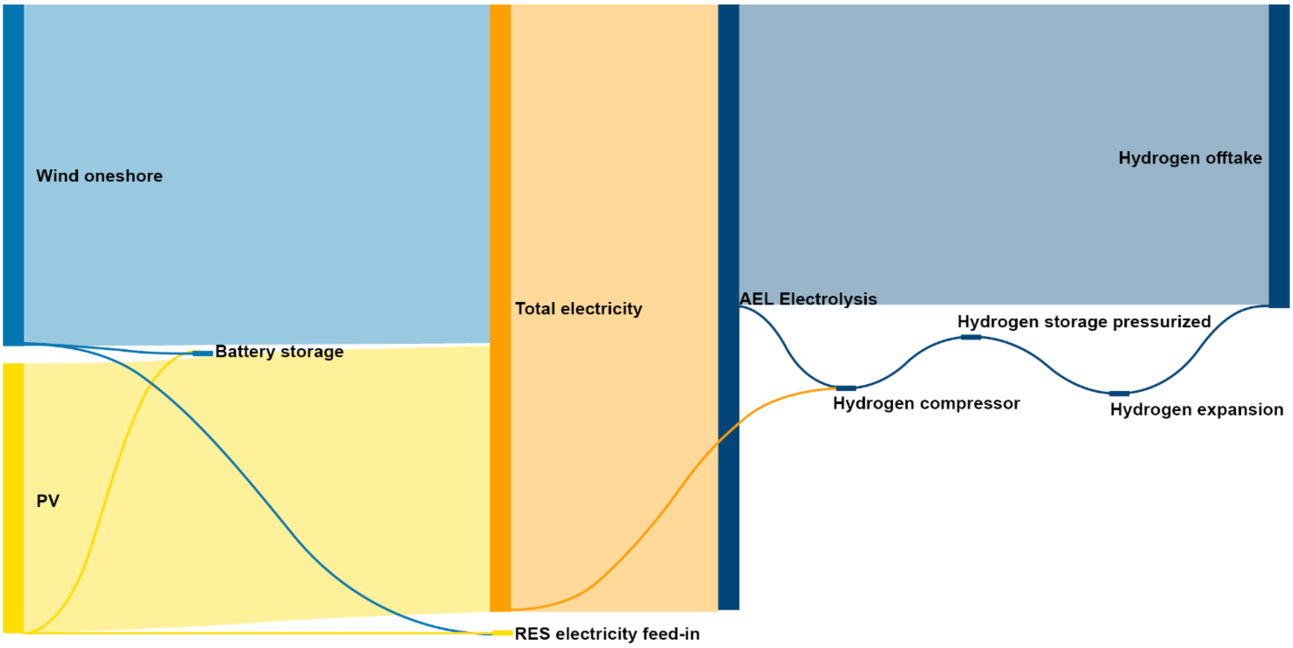

Figure 10: Flow chart for case S4, technology-open, NH_3, 2030

As Figure 10 shows, the least-cost optimization in the technology-open scenario selects a mix of PV and Wind for ammonia production. PV has the lowest LCOE for this site. However, since PV is only available during daytime, the model also covers a considerable share of the energy demand from Wind (on all sites, except S1). The combination of these two RES technologies with different generation profiles allows for a higher capacity factor of downstream components. To cover the minimum electricity demand of electrolysis (1% min turn ratio of modularized AEL electrolyzer plant) during hours of close to zero RES electricity generation, a small battery storage is selected.

To allow for high flexibility of the electrolyzer in the NH_3 scenario, which assumes moderate baseload hydrogen demand to maintain minimum loading of ammonia plant, a pressurized hydrogen storage is also selected.

4.3.2 S4: CSP-PV scenario, NH_3, 2030

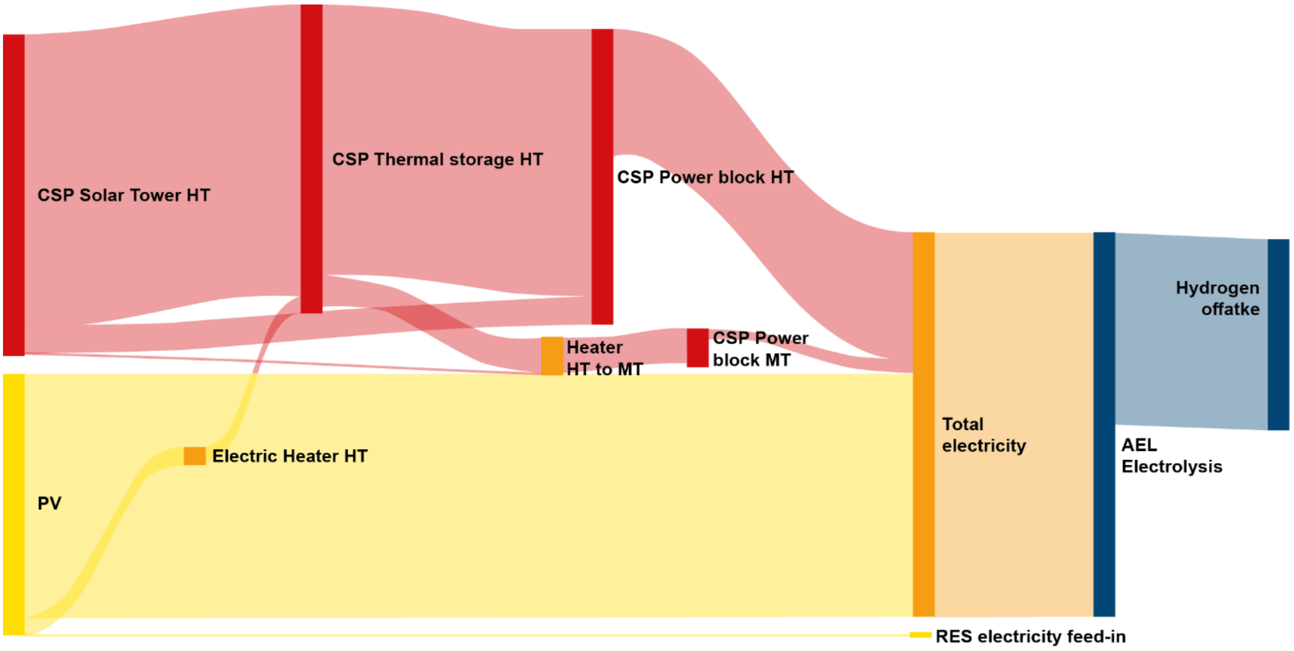

Figure 11: Flow chart for case S4, CSP-PV hybrid, NH_3, 2030

The modelling results for the CSP-PV hybrid scenario (otherwise same scenarios as above) is shown in Figure 11. According to the scenario definition, Wind is not considered in the energy mix. PV as the lowest LCOE energy source still forms a considerable share of the energy mix, but here it is complemented by a considerable share of CSP with large thermal energy storage (TES), which is selected to enable the targeted 60% capacity factor of electrolysis (See: 3.4.3).
As a large TES makes the electricity production highly dispatchable, the electrolyzer does not have to be as flexible, so that hydrogen storage is not selected.

Notably, TES also enables to harness peak PV production via electric heaters, reducing Feed-in/Curtailment of RES electricity from 6.1% in the technology-open scenario to 0.3% in the CSP-PV hybrid scenario.

4.3.3 S4: technology-open scenario, MeOH, 2030

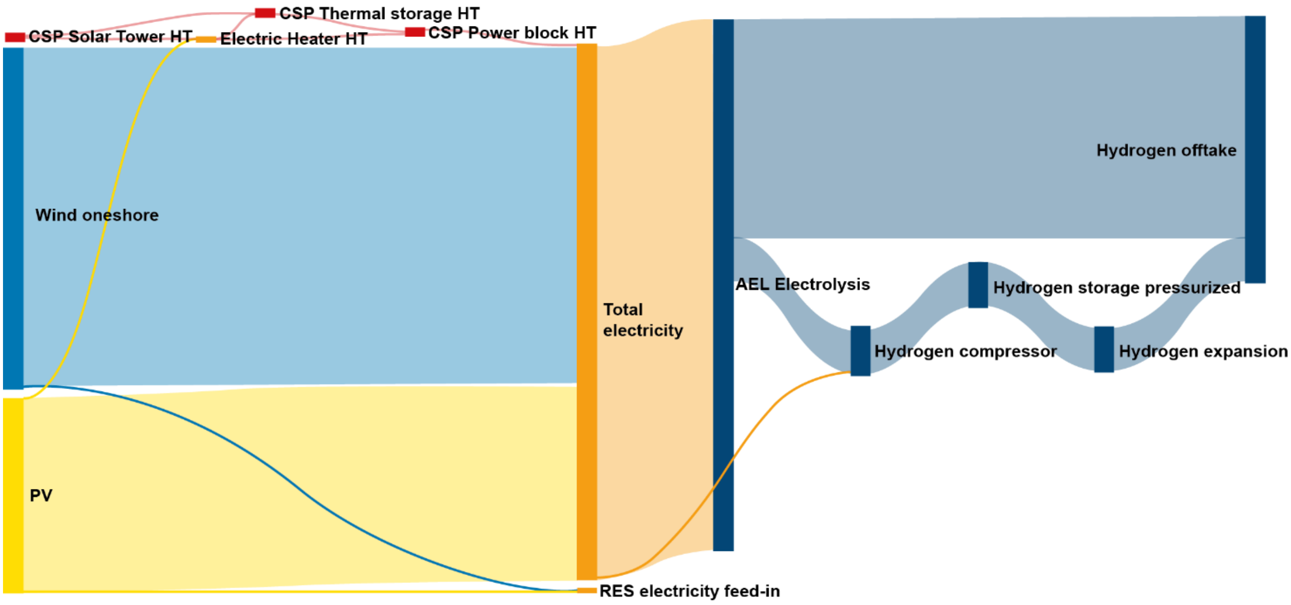

Figure 12: Flow chart for case S4, technology-open, MeOH, 2030

Figure 12 shows the flow chart for methanol production in the technology-open scenario.
While just as for NH_3 production, most of the energy comes from a mix of PV and wind, CSP incl. TES is selected in addition, and the share of hydrogen that is stored in a pressurized hydrogen storage is much larger. Both can be explained by the very high demand for constant H_2 supply in the MeOH scenario. Further differences in optimized system design among the PtX scenarios (H_2/NH_3/MeOH) are elaborated in section **Error! Reference source not found.**. Note that the flow chart shows electricity feed-in to the grid, but not the curtailment of electricity and thermal energy, which is considerably higher (See **Error! Reference source not found.**).

4.3.4 S4: Technology-open scenario, NH_3, 2050

Returning to the technology-open scenario and NH_3 production, but now for 2050, the following constellation is determined by the least-cost optimization (**Error! Reference source not found.**).

By the assumed CAPEX degression by 2050 (See: 3.4.4), the economic optimum shifts noticeably: With an anticipated cost reduction of 79%, high temperature solid-oxide electrolysis (SOEL) replaces AEL as the most economic option.
CSP, despite the much lower CAPEX reduction for 2050 compared to PV and Wind, is now selected in the least-cost scenario. This can be explained by the fact that CSP can directly supply thermal energy input to the electrolysis process, avoiding the Heat-to-Power conversion losses typically associated with CSP, and therefore offering a more cost-competitive energy supply to the PtX production. However, CSP is not solely selected for heat provision. Around half of thermal energy generated in the CSP is converted to electricity complementing PV and Wind.
As in the PV-CSP hybrid scenario (2030), the dispatchability of CSP+TES electricity allows for the omission of hydrogen storage and for the harnessing of excess renewable electricity via electric heaters (0% Feed-in/curtailment).

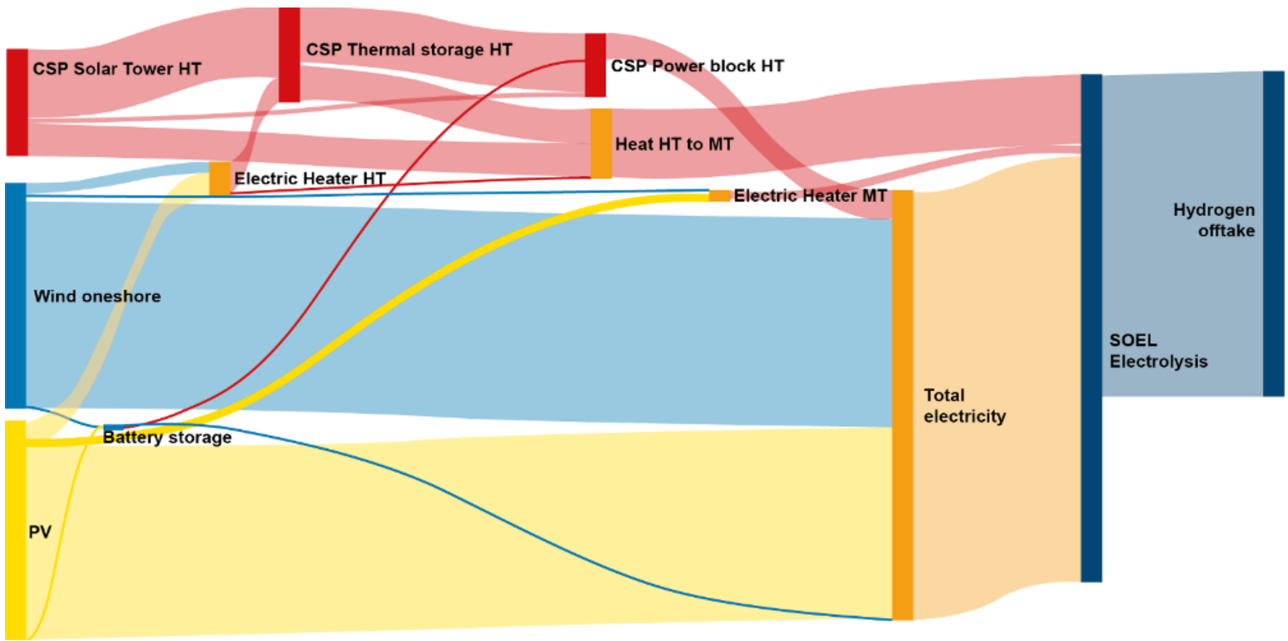

Figure 13: Flow chart for case S4, Technology-open, NH_3, 2025

4.3.5 S4: seasonal variation of PtX production

As mentioned in section 3.4.3 the optimization allows for a seasonal variation in PtX production as the model optimizes against a fix annual production value. It was expected that this would allow the model to match PtX production with the seasonal availabilities of electricity from RES, reducing RES capacity or storage needs to achieve the target annual production.

The following Table 17 shows the margin of seasonal variations in PtX production levels by indicating the largest negative and positive monthly deviations from a seasonally constant production profile. It can be seen that except for the MeOH cases[15], all cases show significant seasonal variations. These results are representative for all sites.

Table 17: Largest deviations from constant production of PtX commodities per month

	Technology-open			PV/CSP hybrid		
	H_2	NH_3	MeOH	H_2	NH_3	MeOH
Min	- 14.7%	- 14.8%	0.0%	- 12.7%	- 12.6%	0.0%
Max	+ 19.7%	+ 19.8%	0.0%	+ 16.6%	+ 16.6%	0.0%

[15] Seasonal variations not permissible by scenario definition, as the minimum turn ratio of methanol synthesis equals the target average capacity factor of the plant. See: 3.4.3

Although the effect on the LCOX cannot be quantified based on the results (lack of reference case), it can be assumed that the seasonal variation does reduce the LCOX, because otherwise it would not occur in all optimized cases. As a rough indication, it can be estimated that all system components would have to be sized larger by the same percentage as the largest negative deviation from a constant production profile to make up for lower RES availability in the respective "worst case" month. On the other hand, sizing all assets for the worst case, would cause significant excess/curtailment during months with higher RES availability.

4.4 LCOX for all scenarios

The following Table 18 present the levelized cost of production for the respective PtX products (LCOX) for both scenarios for 2030 including the average levelized cost of electricity (LCOE) of the selected mix of RES technologies. The table also shows the total capacity (MW) of each of the possible renewable energy sources (Wind, PV, CSP) for the technology open scenario in 2030. The following can be summarized:

- General remark: The modelling is based on a least-cost optimization, meaning the technology is chosen and sized in such a way, that it results in the lowest LCOX. Thus, if CSP is not selected in the technology open scenario, excluding wind as an energy source (CSP-PV hybrid scenario) will result in higher or at most the same LCOX. Note: The model does not consider feed-in tariffs for excess electricity, which might influence the LCOX. For this model from an economic point of view, curtailment has the same effect as grid feed-in.
- LCOE and LCOH are higher in case of a required baseload, this for NH_3 and MeOH production. This can be explained by the fact that a very stable hydrogen supply is required, which requires large storage facilities and the oversizing of electricity generators from renewable energy sources. It should be noted that especially for MeOH production, large amounts of excess electricity need to be either curtailed or fed into the public grid. This implies that improvements of LCOH could be achieved, if remuneration for excess electricity fed into the grid were considered.
- The difference between the LCOM for all five sites a quite small compared to LCOH and LCOA. Further it can be observed, that in case of MeOH production even if the LCOE are quite high in the comparison, the LCOM can be even lower compares to other sites. This can be explained by the higher share of storage costs and thus smaller share of (site-specific) VRE electricity costs in the LCOX for methanol production.
- S2+S5: It is shown that high wind resources are more essential to economic competitiveness of Power-to-X projects than high solar resources. This can be explained by the fact that wind generally has a higher yearly average capacity factor and less variability than solar, which is conducive to higher capacity factors of electrolysis and other PtX processes, yielding better cost-benefit ratios. The lowest LCOE and LCOX in the technology-open scenario occur at site S2, followed by S4 due to higher wind resources for S2. If wind energy is not feasible for this supply, the LCOX increase significantly, as the CSP conditions at these sites are very low.
- S3+S4: However, the comparison between S3, S4 (both with high PV/CSP share and moderate wind) and S5 (with moderate PV share, low CSP share and moderate wind) shows that high solar resources can still give locations with good wind conditions a competitive advantage, as they improve the economic viability of hybrid wind-PV projects.
- S1: Only for S1, a single CSP-PV is the most economic configuration. However, this best-case for CSP-PV hybrid is not competitive with the above-mentioned sites.

Table 18: Levelized cost of X (LCOX) for 2030

(Note that the colour scale is based on horizontal comparison (i.e., among the scenarios) of the respective KPI, with blue colour representing the lowest LCOX and red colour representing the highest LCOX)

		S1			S2			S3			S4			S5		
		Technology open scenario, 2030														
		H_2	NH_3	MeOH	H_2	NH_3	MeOH	H_2	NH_3	MeOH	H_2	NH_3	MeOH	H_2	NH_3	MeOH
PV	MWAC	269	269	378	2	25	269	191	188	294	217	215	280	184	179	278
Wind	MW	0	0	0	334	318	395	302	304	380	273	275	360	321	325	522
CSP	MWth	487	481	758						468			170			
LCOE (Total)	EUR /MWh	55.77	55.79	65.64	29.87	30.15	38.32	38.18	38.24	55.49	38.74	38.79	49.23	40.44	40.48	52.71
LCOH	EUR/kg	5.68	5.68	7.42	3.98	4.00	6.54	4.75	4.76	7.71	4.71	4.72	6.60	4.83	4.83	7.99
LCOA	EUR/t		1,142			850			984			973			996	
LCOM	EUR/t			1,693			1,526			1,747			1,536			1,801
		Percentage change (%) CSP-PV, 2030														
LCOE (Total)	EUR /MWh	0%	0%	0%	51%	55%	23%	61%	61%	7%	62%	62%	93%	26%	26%	-10%
LCOH	EUR/kg	0%	0%	0%	83%	83%	65%	34%	35%	22%	35%	35%	29%	60%	60%	50%
LCOA	EUR/t		0%			69%			30%			30%			52%	
LCOM	EUR/t			0%			53%			19%			23%			42%

Reference values for LCOX for 2030

In external literature, i.e., preceding studies, following levelized production costs were determined:

- LCOH: 4.6-5.5 EUR/kg (Fraunhofer ISE, 2023), 4.7 EUR/kg (DLR, 2022)
- LCOA: 1033-1266 EUR/t (Fraunhofer ISE, 2023), 600 EUR/t (Cesaro et al., 2021)
- LCOM: 1128-1379 EUR/t (Fraunhofer ISE, 2023), 1200 EUR/t (IRENA, 2021b)

The LCOX values determined in this study are generally in a similar range but higher than the reference values. This could be due to more conservative, i.e., higher cost parameters assumed (see Appendix A). This should be considered when comparing the above values with those from other studies.

The comparison of LCOX between commissioning year of 2030 and 2050 for the technology open scenario shows following results:

- As a result of the assumed CAPEX degression by 2050 the LCOX of all PtX products are generally also expected to fall with cost reduction between (-)19% to (-)40%
- The LCOX reduction for 2050 is higher for sites with high solar resources due to a higher assumed cost reduction for PV than for wind.

4.5 Environmental and Social KPIs for 2030

Table 19 presents the environmental and social KPIs for each case, which are calculated based on the optimized installed capacities and annual commodity flows (See Appendix D: Detailed site-specific results). For the evaluation of environmental and social KPIs, the PtX value chain is only evaluated up to the production of hydrogen, which is the common core of all PtX value chains considered in this study. The synthesis of derivatives (e.g., water demand of the Haber-Bosch process) is not considered to allow for better comparability of the results among different PtX cases.

Table 19: Water demand, Land use and job creation per tonne of Hydrogen produced for 2030

(Note: the colour scale is based on horizontal comparison (i.e., among the scenarios) of the respective KPI, with blue colour representing the best and red colour representing the worst value.)

		S1			S2			S3			S4			S5		
		Technology open scenario, 2030														
		H_2	NH_3	MeOH	H_2	NH_3	MeOH	H_2	NH_3	MeOH	H_2	NH_3	MeOH	H_2	NH_3	MeOH
Water demand	$m^3/t\ H_2$	20,.	20.3	19.6	13.8	13.8	13.9	13.8	13.8	14.4	13.8	13.8	13.9	13.8	13.8	14.0
Land use	$m^2/t\ H_2$	9,.	9.6	12.1	20.3	19.9	30.6	22.5	22.5	31.5	21.3	21.4	28.9	23.5	23.6	39.2
Employment	jobs/ kt H_2	6,.	6.2	7.1	5.8	5.8	8.9	6.7	6.7	9.7	6.6	6.6	8.7	6.9	6.9	10.9
		CSP-PV hybrid scenario, 2030														
		H_2	NH_3	MeOH	H_2	NH_3	MeOH	H_2	NH_3	MeOH	H_2	NH_3	MeOH	H_2	NH_3	MeOH
Water demand	$m^3/t\ H_2$	20.3	20.3	19.6	19.5	19.6	19.8	20.6	20.6	20.4	21.1	21.1	21.2	19.9	19.9	20.4
Land use	$m^2/t\ H_2$	9.7	9.6	12.1	19.1	18.5	21.6	11.5	11.5	13.5	10.7	10.7	7.9	19.4	19.3	26.9
Employment	jobs /kt H_2	6.2	6.2	7.1	9.4	9.2	9.1	7.1	7.1	6.7	6.7	6.7	5.1	9.7	9.7	11

In the following the results are explained and set in the context of the selected energy mix (see 4.2). Following observations can be made:

Water demand is relatively lower in the high Wind and PV cases and higher when CSP is used. CSP, unlike to PV and Wind has some water consumption (0.3 m^3/MWh_{el}). This is related to the make-up water (compensation for losses) of the steam cycle of the power block (heat-to-power conversion).
Furthermore, in cases where SOEL electrolysis is used, water consumption is higher. This is related to the usage of pressurized steam as an input to SOEL (modelled here as demineralized water + heat). Naturally, water in the form of vapor is lost more easily than liquid water, e.g., it cannot be separated that easily from the gaseous oxygen which needs to be vented from the electrolyzer.

Regarding **Land use**, the opposite is observed: It is lower for high CSP shares in the energy mix and higher for large wind capacities. PV represents the middle ground in terms of land use. This can be directly attributed to the assumptions regarding land use per MW installed (High land use in cases with onshore Wind, especially in MeOH cases as high baseload requires oversizing of RES)

In the case of **Employment,** the highest job creation values are observed for the largest installed capacities of renewables. This can be explained by the fact that job creation is estimated based on installed capacity per technology (jobs/MW). The installed capacities (MW) are thus the sole driver of high job creation. Installed capacities also drive CAPEX and OPEX, which feed into LCOX calculation. It should be noted, that CSP has by far the largest value for specific job creation (13 jobs/MW).

5 Conclusions

System selection

- Under current price developments for mainly electrolysers, the use of pure CSP-PV hybrid plants for production of green hydrogen, ammonia, or methanol for a specific site, is only economical reliable under excellent solar conditions or without adequate wind resources (results site 1)
- In the case of excellent wind conditions, PV wind hybrid plants are more economically viable. Further, in these cases even wind power plants are not possible to build, CSP has only a limited role or even pure PV plants without CSP would be the economical reliable case (results scenario 2 & 5)
- With regard to the use of CSP among the value chains of different PtX commodities, especially changes from pure hydrogen production (assuming flexible production) to PtX processes with high base load requirements (in this case methanol production – min. loading of 80%), CSP in combination with a thermal energy storage (CSP) is an economic choice in combination with Wind and PV for sites with high PV and CSP conditions combined with moderate wind conditions (scenario 3 & 4)
- In contrast, a moderate baseload demand (in this case ammonia production – min. loading of 20%) has little effect on the system layout and storage requirements of PtX value chains. A moderately sized hydrogen storage and in some cases a higher grade of hybridisation of RES technologies is mostly sufficient to cover the requirements of NH_3 production with little impact on the economics of green hydrogen production, i.e., the LCOH varies very little between the H_2 and the NH_3 scenario. (scenario 1-5)
- Assuming the different rates of cost degression per technology, considerable shifts in the system constellations resulting from least-cost optimization can be observed. With the highest expected cost reduction of 79% for high temperature solid-oxide electrolysis (SOEL), it replaces AEL as most economic option in most 2050 cases.

The role of CSP

- The analysis of 60 different cases shows that CSP does have economic use cases for PtX production in CSP-PV-Wind hybrid constellations, i.e., as a tertiary energy source or even primarily as a storage or backup technology. As thermal energy – whether from CSP thermal collector fields or produced from surplus electricity via electric heaters – can be stored at very low costs, it can offer an attractive complement to PV-Wind hybrids. The lower efficiency of (power-to-) heat-to-power storage options can be tolerated, if it is only needed for limited time periods, e.g., during rare coincidence of (close to) zero generation from both wind and PV. The dispatchability of CSP electricity reduces the need for other storage technologies (battery, hydrogen storage).
- Furthermore, the integration of (CSP and) TES allows for the harnessing of excess renewable electricity via electric heaters, which would otherwise be curtailed or fed into the public grid for little or no remuneration.
- The combination of Electric heater, TES and Power block can outperform Battery Energy Storage System (BESS) as electricity storage – even without a solar thermal collector. This can be explained by the momentary low value of electricity during peak production. Especially as no feed-in tariff for surplus generation is considered, this electricity is virtually free. Therefore, even the high conversion losses of a power-to-heat-to-power storage can be outweighed by the low CAPEX of thermal energy storage. The advantage of a low-CAPEX storage technology is also favoured by low-capacity factors of storage, i.e., if storage only acts as a backup during rare occasions of minimum production of all RES generators.
- The solar tower CSP technology is preferable compared to parabolic trough systems, as it achieves higher capacity factors, and its higher operating temperature allows for higher heat-to-power conversion efficiency and higher energy density in thermal storages.
- When Solid Oxide Electrolysis (SOEL) become affordable, CSP becomes more attractive as it can provide cheap, renewable thermal energy, avoiding heat-to-power solutions with conversion losses.

LCOX

- The combination of multiple RES technologies with different generation profiles allows for a higher capacity factor of Power-to-X processes/plants, improving the overall economics of PtX projects (lower LCOX).
- A site with high wind resources is more essential to economic competitiveness of Power-to-X projects than high solar resources because generally wind has a higher yearly average capacity factor and less variability. However, good solar resources, including for CSP, can offer a competitive advantage for hybrid PtX projects.
- Low levelized cost of energy (LCOE) are beneficial, however the complementary energy generation of RES and thus the minimization of storage capacities influence the levelized costs of PtX production (LCOX).
- With further CAPEX degression, the LCOX of all PtX products will generally decrease.

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7 Appendix

7.1 Appendix A: Assumptions book – Techno-economic parameters used for the optimization

Investment costs (CAPEX) are given as total installation cost (TIC), which typically includes equipment, design allowance, bulk materials, transport, mechanical installation, civil & subcontract works, engineering & supervision, but excludes contingencies, owner's costs, VAT, and impot tax, as these are typically not considered within a general economic analysis, but only in project-specific financial/commercial analyses.

7.1.1 General project framework

Table 20: General economic parameters

Parameter	Unit	Value
Discount rate (Typically: Weighted average cost of capital – WACC)	%	8
Commercial operational date (COD) or year of commissioning	year	2030 (2050[16])
Time horizon (operation)	years	25
Currency	-	USD

7.1.2 Charges & Commodity prices

Some commodities or services are not (entirely) generated and consumed within the system boundaries of the hydrogen/ammonia/methanol value chain, but are imported / exported at the following specific costs:

Table 21: Commodities parameters

Parameter	Unit	Value	Reference / Consultant Comment
Desalinated water	USD/kg H_2O	0.001	Consultant project experience
Feed-in remuneration for surplus electricity (if any)	USD/kWhel	0	Not considered in the economic optimization

[16] Applied for future scenario, See: 3.4.4 Time horizons

7.1.3 Renewable electricity supply

Table 22: Wind farm parameters

Parameter	Unit	Value	Reference / Consultant Comment
Type	-	Wind Park	
Minimum capacity	MW	0	Assumption
Maximum capacity	MW	-	Assumption
Specific CAPEX	USD/kW	1,100 (-23%[17])	Consultant project experience
Specific fixed OPEX	USD/kW/year	13	Consultant project experience
Specific variable OPEX	USD/kWh	-	Consultant project experience
System lifetime	years	25	Consultant project experience

Notes: 8760h generation profile(s) [$MW/MW_{installed}$] are determined per site using publicly available data[18].
Dataset: MERRA-2, Turbine Type considered: Vestas V90 2000

Table 23: PV plant parameters

Parameter	Unit	Value	Reference / Consultant Comment
Type	-	Single-axis tracking	
Minimum capacity	MW_{AC}	0	Assumption
Maximum capacity	MW_{AC}	-	Assumption
DC/AC ratio	MW_{DC} /MW_{AC}	1.4	Consultant project experience
Specific CAPEX	USD/kW_{AC}	910 (-31%[19])	Consultant project experience
Specific fixed OPEX	USD/kW_{AC} /year	13.7 (1.5% of CAPEX)	Consultant project experience
Specific variable OPEX	USD/kWh_{AC}	-	Consultant project experience
System lifetime	years	30	Consultant project experience

Notes: 8760 h generation profile(s) [$MW/MW_{installed}$] are determined per site using commercial weather data (Meteonorm), considering a typical meteorological year.

17 Applied for future scenario, See: 3.4.4 Time horizons
18 Staffell et al. (2016), https://www.renewables.ninja/about
19 Applied for future scenario, See: 3.4.4 Time horizons

Table 24: CSP Solar field parameters

Parameter	Unit	Value		Reference / Consultant Comment
Type	-	Solar Tower	Parabolic Trough	
Max. operating temperature	°C	560	400	Solar field type affects values for Power block and TES
Minimum capacity	MW_{th}	0	0	Not reproduceable
Maximum capacity	MW_{th}	400	800	Largest sizes realized so far
Specific CAPEX	USD/kW_{th}	316 (-7%[20])	216 (-7%[21])	Battery limits heat management system to TES / SG
Specific fixed OPEX	USD/kW_{th} /year	18	15	Assumes SF and heat management maintenance, operation done with Powerblock
Specific variable OPEX	USD/kWh_{th}	0	0	Operation in power block assumptions
System lifetime	years	25	25+	PBT more modular than Central Receiver system, lifetime almost not limited

Notes: 8760 h generation profile(s) [MW_{th}/MW_{th},installed] are determined per site using commercial weather data (Meteonorm), considering a typical meteorological year. CSP Thermal output timeseries is simulated using the tool System Advisor Model (SAM) by NREL.

7.1.4 Storage technologies

Table 25: CSP Power block parameters

Parameter	Unit	Value		Reference / Consultant Comment
Type	-	Steam cycle (560 °C) Air-cooled condenser	Steam cycle (400 °C) Air-cooled condenser	
Minimum capacity	MW_{AC}	0	0	Not reproduceable
Maximum capacity	MW_{AC}	150	280	Realized so far

[20] Applied for future scenario, See: 3.4.4 Time horizons
[21] Applied for future scenario, See: 3.4.4 Time horizons

Parameter	Unit	Value		Reference / Consultant Comment
Thermal Efficiency	%	43	35	Consultant experience, Li et al. (2019)
Specific CAPEX	USD/kW_{AC}	1400 (-7%[22])	1300 (-7%[23])	Consultant experience, IRENA (2012)
Specific fixed OPEX	$USD/kW_{AC}/year$	45	39	Consultant experience,
Specific variable OPEX	USD/MWh_{AC}	3.2	3.2	Here operation cost including for Solar field/TES
System lifetime	years	25	25	Consultant experience

Table 26: TES parameters

Parameter	Unit	Value		Reference / Consultant Comment
Type	-	Molten Salt Tanks (560 °C)	Molten Salt Tanks (400 °C)	
Minimum capacity	MWh_{th}	0	0	Not reproduceable
Maximum capacity	MWh_{th}	4200 (-7%[24])	4500 (-7%[25])	Largest sizes realized so far
Max. DoD	% of nominal capacity	95%	95%	
Specific CAPEX	USD/kWh_{th}	20	24	Less molten salt (volume) versus higher cost of steel in HT TES Consultant experience
Specific fixed OPEX	$USD/kWh_{th}/year$	0.6	0.6	Consultant experience
Heat losses	%/h	0.09	0.09	According to realized design specifications
System lifetime	years	25	25	Corrosion reserve designed for ~25 years

[22] Applied for future scenario, See: 3.4.4 Time horizons
[23] Applied for future scenario, See: 3.4.4 Time horizons
[24] Applied for future scenario, See: 3.4.4 Time horizons
[25] Applied for future scenario, See: 3.4.4 Time horizons

Table 27: Electric Heater parameters

Parameter	Unit	Value		Reference / Consultant Comment
Type	-	Electric Resistance Heater (Molten Salt, 560 °C)	Electric Resistance Heater (Molten Salt, 400 °C)	
Minimum capacity	MW_{th}	0	0	
Maximum capacity	MW_{th}	12	12	Realized size, however, modular
Efficiency (power to heat)	%	93,5 %	95 %	Consultant experience
Specific CAPEX	USD/kW_{th}	148.5 (-7%[26])	110 (-7%[27])	Consultant experience (10-12 MW), Iñigo-Labairu et al. (2022)
Specific fixed OPEX	$USD/kW_{th}/year$	0.8	0.8	Consultant experience
System lifetime	years	25	25	Corrosion reserve designed for ~25 years

Table 28: Battery storage parameters

Parameter	Unit	Value	Reference / Consultant Comment
Type	-	Li-ion, Utility-scale	Assumption
Minimum unit size	MWh		10
Specific CAPEX	USD/kWh +USD/kW	300 (-25%[28]) 100 (-25%[29])	Consultant project experience
Specific fixed OPEX	USD/kWh/year +USD/kW/year	4.0 0.5	Consultant project experience
Roundtrip efficiency	%	85	Consultant project experience
Max DoD	%	80	Consultant project experience
System lifetime	years	15	Consultant project experience

[26] Applied for future scenario, See: 3.4.4 Time horizons
[27] Applied for future scenario, See: 3.4.4 Time horizons
[28] Applied for future scenario, See: 3.4.4 Time horizons
[29] Applied for future scenario, See: 3.4.4 Time horizons

Battery limits:

- ISBL[30]: Battery Energy Storage system (BESS: Racking Frame/Building, Battery Management System, Battery Modules) and Power Conversion System (PCS: Inverter, Protections (Switches, breakers, etc.), Energy Management System)
- OSBL: AC Transformer

Notes: The storage capacity determined by the techno-economic optimization represents only operational storage, which is used under ideal conditions. Strategic storage (e.g., to increase system resilience in case of power cuts) is not considered.

7.1.5 Hydrogen production

1.1.1.3 Water treatment (demineralization)

Desalinated water is considered a utility. As its quality (mineral content) is not sufficient to be used directly as feedstock for electrolysis, additional demineralization and polishing stages will be required. The following parameters will be considered.

Table 29: Demineralization parameters

Parameter	Unit	Value	Reference / Consultant Comment
Type	-	RO-EDI	
Specific electricity demand	$kWh_{el}/kg_{H2O\ (product)}$	0.0006	Consultant project experience
Specific tap water demand (recovery)	$kg_{H2O\ (raw)}/kg_{H2O\ (product)}$	~1.5	Consultant project experience
Specific CAPEX	$USD/(kg_{H2O\ (product)}/h)$	140	Consultant project experience
Specific fixed OPEX	$USD/(kg_{H2O}/h)/year$	1.5	Consultant project experience
System lifetime	years	25	Consultant project experience

[30] ISBL = Inside battery limit; OBSL = Outside battery limit

Table 30: Electrolysis parameters

Parameter	Unit	Value		Reference / Consultant Comment
Type	-	AEL	SOEL	
Specific electricity demand Balance of Plant (BoP)	$kWhel/kg_{H2}$	53.4 (62% el. Efficiency)	41.2 (81% el. Efficiency)	Beginning of life (BOL) value. Efficiency degradation applies. PROSUMER will use average value as constant.
Specific heat demand (steam)	$kWhth/kg_{H2}$	-	8.3	Calculated based on spec. steam demand of 11.1 kg/kg_{H2} at 150 °C and 3 bar
Specific demineralized water demand (electrolysis)	kg_{H2O}/kg_{H2}	9.3	11.1	Consultant database
Minimum turn ratio	%	1	30	Modular design of AEL should allow high flexibility of the plant
Specific CAPEX (2022 data)	USD/ kWel	1,100 (-27%[31])	2,250 (-79%[32])	Consultant database, (NOW, 2018)
CAPEX stack replacement	% of CAPEX	30	30	Consultant project experience
Specific fixed OPEX (O&M)	USD/ kWel/year	20	32.5	Consultant database, (NOW, 2018)
Stack replacement interval	years	10	10	Consultant project experience
Technical plant lifetime	years	25	25	Consultant project experience

[31] Applied for future scenario, See: 3.4.4 Time horizons
[32] Applied for future scenario, See: 3.4.4 Time horizons

Table 31: Hydrogen compression parameters

Parameter	Unit	Value		Reference / Consultant Comment
Type	-	Piston compressor (0.15 to 30 barg)	Piston compressor (30 to 100 barg)	Assumption
Min. surge pressure	barg	0.15	30	Consultant Database
Max. discharge pressure	barg	30	100	Consultant Database
Specific electricity demand	kWh_{el}/kg_{H2}	1.662	0.696	Consultant Database
Minimum turn ratio	% of nominal capacity (per unit)	25	25	Not considered in PROSUMER (modular design allows high flexibility)
Specific CAPEX	$USD/(kg_{H2}/h)$	3380	3910	Consultant Database
Specific fixed OPEX (O&M)	$USD/(kg_{H2}/h)$ /year	175	100	Consultant Database
Technical plant lifetime	years	25	25	Consultant Project experience

Table 32: High Pressure storage parameters

Parameter	Unit	Value	Reference / Consultant Comment
Type	-	compressed gas, pressure vessels	Assumption
Minimum size	kg_{H2}	0	Assumption
Maximum size	kg_{H2}	-	May be limited by land availability constraints.
Minimum operating pressure	barg	30	Assumption
Max. DoD	% of nominal capacity	69	Consultant Database
Maximum operating pressure	barg	100	Assumption
Hydrogen loss	%/day	0	(Assumption)
Specific CAPEX	USD/kg_{H2}	730	Consultant Project experience
Specific fixed OPEX	$USD/kg_{H2}/year$	20	Consultant Project experience
System lifetime	years	25	Consultant Project experience

Notes: The storage capacity determined by the techno-economic optimization represents only operational storage, which is used under ideal conditions. Strategic storage (e.g., to increase system resilience in case of power cuts) is not considered.

7.1.6 Ammonia production

This section lists techno-economic parameters for the production of ammonia from hydrogen. The parameters are used to determine hydrogen demand profiles (min. baseload) and to estimate the levelized production cost of ammonia (LOCA). The air separation unit is required to produce Nitrogen (N_2) from ambient air. N_2 is required in addition to hydrogen for the synthesis of ammonia.

Table 33: Ammonia synthesis parameters

Parameter	Unit	Value	Reference / Consultant Comment
Type	-	Haber-Bosch reactor	Consultant project experience
Specific electricity demand	kWh_{el}/kg_{NH3}	0.35	Consultant project experience
Specific hydrogen demand	kg_{H2}/kg_{NH3}	0.18	Consultant project experience
Specific nitrogen demand	kg_{N2}/kg_{NH3}	0.83	Consultant project experience
Minimum turn ratio	% from nominal capacity	20	Consultant project experience
Specific CAPEX	$USD/(kg_{NH3}/h)$	3900	Consultant project experience
Specific fixed OPEX	$USD/(kg_{NH3}/h)/year$	200	Consultant project experience
System lifetime	years	25	

Table 34: Air Separation parameters

Parameter	Unit	Value	Reference / Consultant Comment
Type	-	Cryogenic air separation	
Specific electricity demand	kWh_{el}/kg_{N2}	0.24	
Specific CAPEX	$USD/(kg_{N2}/h)$	2500	Consultant project experience
Specific fixed OPEX	$USD/(kg_{N2}/h)/year$	50	~2% of CAPEX
Average capacity factor	%	80	Consultant experience
System lifetime	years	25	

7.1.7 Methanol production

This section lists techno-economic parameters to produce methanol from hydrogen. The parameters are used to determine hydrogen demand profiles (min. baseload) and to estimate the levelized production cost of methanol (LCOM).

Table 35: Methanol synthesis parameters

Parameter	Unit	Value	Reference / Consultant Comment
Type	-	e-methanol synthesis plant	
Specific electricity demand	kWh_{el}/kg_{MeOH}	0.79	
Specific hydrogen demand	kg_{H2}/kg_{MeOH}	0.19	
Specific carbon dioxide demand	kg_{CO2}/kg_{MeOH}	1.37	

Parameter	Unit	Value	Reference / Consultant Comment
Specific carbon dioxide cost	USD/t_{CO2}	120	Costs include capturing & transport. Consultant project experience (See below)
Minimum turn ratio	% from nominal capacity	80	Consultant project experience
Specific CAPEX	USD/(kg_{MeOH}/h)	5,600	Consultant project experience
Specific fixed OPEX	USD/(kg_{N2}/h)/year	110	Consultant project experience
Average capacity factor	%	90	Consultant experience
System lifetime	years	25	

Notes: Consultant project experience on biogenic CO_2 as a feedstock, which is required for green methanol synthesis: Availability is highly site specific and requires thorough research on potential industrial sources, i.e., industrial processes such as cement production, waste incineration, biomass power plants or bioethanol production, within a radius of up to 300 km around the methanol production site. The value of 120 USD/t_{CO2} was taken from a reference project in Egypt, where a cement plant with 40% biogenic carbon with 50 km distance to the methanol production site was considered.

7.2 Appendix B: Environmental, social, technological performance indicators of considered technologies

7.2.1 CSP

The area requirements for CSP can vary depending on various factors, such as the size, the solar multiple for storage operation and type of CSP or the location. The average value is assumed to be 2 [ha/MW] (IRENA, 2013).
The number and type of jobs varies according to the type of CSP technology, economic and legislative framework conditions of the country, and the development level of related sub-industries. According to (AfDB, 2016) the total (including up and down stream value chain) average number of jobs are 13 [jobs/MW].
CSP plants using steam cycles require cooling (i.e. 2-3 m^3 of water per MWh) to condense the exhaust steam from the turbines. The lower the efficiency, the higher the cooling needs. As water resources are often scarce in Sun Belt regions, wet or dry cooling towers are often needed for CSP installations. In general, dry (air) cooling towers are more expensive and less efficient than wet towers. They reduce the electricity production by around 7% and increase the capital cost by 10% but need just 10% water compared to wet towers.

Table 36: Selected performance indicators for CSPs

KPIs	Values	Reference
Employment [jobs/MW]	13	(AfDB, 2016)
Water [m^3/MWh_{el}]	0.3	(IRENA, 2013)
Area[33] [ha/MW]	~2	(IRENA, 2013)

[33] Average value

7.2.2 Wind

Overall, the water usage associated with wind energy is very low compared to other forms of energy production, such as fossil fuels or nuclear power.
The number and type of jobs varies according to the type of technology used, the economic and legislative framework conditions of the country, and the development level of related sub-industries. According to Aldieri et al., 2019, for wind energy the mean (range)[34] total jobs are (5.2-16.55) jobs/MW.
The square meter requirements for wind energy production can vary depending on various factors, such as the size and type of the wind turbine and the location of the wind farm. (Enevoldsen and Jacobson, 2021) indicate that the mean (range) installed and output for power densities of onshore wind farms in Europe are 19.8 (6.2-46.9) MW/km², for onshore wind farms outside of Europe are 20.5 (16.5-48) MW/km² and for offshore wind farms in Europe are 7.2 (3.3-20.2) MW/km².

Table 37: Selected performance indicators for wind-turbines

KPIs	Values	Reference
Employment	5.2-6.55	(Aldieri et al., 2019)
Water	-	-
Area [MW/km²]	(16.5-48)	(Enevoldsen and Jacobson, 2021)

7.2.3 PV

The improvement of n-type over p-type has a direct positive impact on both power density (MWp/ha) and energy density (MWh/ha) over time for both fixed-tilt and tracking plants which has been driven in large part by the increase in module wattage, higher efficiencies, lower temperature coefficient and lower annual degradation. Whereas Ground Coverage Ratios (GCR) vary strongly from site to site, the median (along with 25th-75th percentile range) shows already in 2019 Power densities of 0.875 MWp/ha for fixed tilt, and 0.675 MWp/ha for tracker. Median of Energy density has been estimated at 1.125 MWh/(a*ha) for Fixed tilt and 975 MWh/(a*ha) for Trackers. (IEEE, 2022). These values have all improved by the latest module technologies (bifacial, n-type) which are not captured in these estimates.
PV Plants, by their inherent technology, do not require any water during operation unless the operator chooses wet cleaning methods. Many plants in the Middle East such as Benban in Egypt and Al-Maktoum parks in UAE decided for dry cleaning using water-free robots. In exceptional cases, very few times in a year the operator might use water for a cleaning cycle.
PV, as well as other renewable energy activities have the potential of creating jobs along the value chain. A study of AfDB (2016) estimated the number of jobs for PV at 3.5 jobs/MW installed for upstream value chain, and 5-14 jobs/MW installed downstream value chain.

[34] Excluding outlier

Table 38: Selected performance indicators for PV

KPIs	Values	Reference
Employment - upstream - downstream	~3.5 ~5-14	(AfDB, 2016)
Water (dry cleaning, standard case Middle East North Africa)	0	-
Area (2019 median) [MW/ha] fixed tilt [MW/ha], Trackers [MWh/a.ha], fixed tilt [MWh/a.ha], Trackers	 0.875 0.675 1.125 975	(IEEE, 2022)

7.2.4 Electrolysis

Current status

The current KPIs for the three considered electrolyser technologies (AEL, PEM, SOEL) are shown in **Error! Reference source not found.**,
 and **Error! Reference source not found.** for PEM, AEL and SOEL respectively.
When all technologies are compared against each other, the SOEL technology has the highest system efficiency but is not yet commercially available in the higher scale ranges. When only commercially available technologies are compared, AEL has a slightly higher efficiency compared to PEM. However, since AEL is typically operating at atmospheric pressure levels, additional energy demand for mechanical compression needs to be considered to deliver hydrogen at the same pressure level than PEM systems.
Based on the data from Fraunhofer (ISE, 2021) it can be observed that for large-scale electrolysis plants the system efficiency decreases (+0.6 kWh/kg for AEL and +0.9 kWh for PEM). According to Fraunhofer this is due to additionally required high-voltage transformers and associated losses. It should be noted that the efficiency of an electrolysis plant strongly depends on the plant design. Therefore, the efficiency should be regarded on a project-specific basis.
The specific deionized (DI) water demand for AEL systems is slightly higher compared to PEM, but when comparing the different capacity scales within a technology it is the same. The tap water demand to produce 1 Nm^3 of hydrogen is 1 to 2 L (Fraunhofer ISE, 2021).

Table 39: Technical KPIs AEL electrolysis

KPI	Unit	Value	Source
Stack operational lifetime	h	60,000	IRENA (2020)
Efficiency degradation	%/a	N/A[35]	
Load range	%	15 - 100	IRENA (2020)
5 MW scale			
System efficiency	kWh_{el}/kg_{H2}	52.8	Fraunhofer ISE (2021)
H_2 outlet pressure	-	Atmospheric	Fraunhofer ISE (2021)

[35] Assumption 1%/a

KPI	Unit	Value	Source
Stack operational lifetime	h	60,000	IRENA (2020)
Efficiency degradation	%/a	N/A[35]	
Load range	%	15 - 100	IRENA (2020)
Spec. DI water demand	L/kg_{H2}	9.3	Fraunhofer ISE (2021)
100 MW scale			
System efficiency	kWh_{el}/kg_{H2}	53.4	Fraunhofer ISE (2021)
H_2 outlet pressure	-	Atmospheric	Fraunhofer ISE (2021)
Spec. DI water demand	L/kg_{H2}	9.3	Fraunhofer ISE (2021)

Table 40: Technical KPIs PEM electrolysis

KPI	Unit	Value	Source
Stack operational lifetime	h	65,000	IRENA (2020)
Efficiency degradation	%/a	N/A[36]	
Load range	%	5-120	IRENA (2020)
5 MW scale			
System efficiency	kWh_{el}/kg_{H2}	54.2	Fraunhofer ISE (2021)
H_2 outlet pressure	barg	30	Fraunhofer ISE (2021)
Spec. DI water demand	L/kg_{H2}	9.1	Fraunhofer ISE (2021)
100 MW scale			
System efficiency	kWh_{el}/kg_{H2}	55.1	Fraunhofer ISE (2021)
H_2 outlet pressure	barg	30	Fraunhofer ISE (2021)
Spec. DI water demand	L/kg_{H2}	9.1	Fraunhofer ISE (2021)

[36] Assumption 1.3%/a

Table 41: Technical KPIs SOEL electrolysis

KPI	Unit	Value	Source
Stack operational lifetime	h	20,000	IRENA (2020)
Efficiency degradation	%/a	4	FCH (2015)
Load range	%	30 - 125	IRENA (2020)
System efficiency	kWh_{el}/kg_{H2}	42.3	NOW (2018)
H_2 outlet pressure	barg	5	NOW (2018)
Spec. DI water demand	L/kg_{H2}	N/A[37]	

Medium-term 2030

In the following tables, the expected development of the KPIs for the year 2030 are described. Further technology improvements are expected by 2030, both regarding the electrolysis cells and stack design as well as regarding power electronic devices (rectifiers). The overall system efficiencies for the three electrolyser technologies are further improved compared to the current status.

The specific water demand and the hydrogen outlet pressure are expected to remain at the current level for AEL and PEM technology[38], as shown in **Error! Reference source not found.** and **Error! Reference source not found.**.

Exceptionally the hydrogen outlet pressure for the AEL technology in the 1 GW scale is assumed to increase to 5 bara, as a trade-off between the advantages of atmospheric and pressurized electrolysis regarding the lower gas hold-up with increased pressure and lower gas cross-over at the membrane at lower pressure levels (ISPT, 2022).

In the medium-term view only AEL and PEM electrolysis technologies are considered to be commercially available at the 1 GW scale.

In contrast to the current technology status, it is expected that in the medium-term PEM system will be able to outperform the AEL system in terms of system efficiency.

As shown in **Error! Reference source not found.** the operating pressure of SOEL electrolysis is expected to increase to approx. 12 barg in 2030.

Table 42: Technical KPIs AEL electrolysis

KPI	Unit	Value	Source
		5 MW scale	
System efficiency	kWh_{el}/kg_{H2}	48.9	(Fraunhofer ISE, 2021)
H_2 outlet pressure	-	Atmospheric	(Fraunhofer ISE, 2021)
Spec. DI water demand	L/kg_{H2}	9.3	(Fraunhofer ISE, 2021)
		100 MW scale	
System efficiency	kWh_{el}/kg_{H2}	49.4	(Fraunhofer ISE, 2021)
H_2 outlet pressure	-	Atmospheric	(Fraunhofer ISE, 2021)
Spec. DI water demand	L/kg_{H2}	9.3	(Fraunhofer ISE, 2021)

[37] Assumption: 14 L/kg_{H2} tap water quality
[38] It should be noted that from the market perspective, electrolysis systems with different operating pressures are available (1-20 bar for AEL, 1-40 bar PEM)

KPI	Unit	Value	Source
1 GW scale			
System efficiency	kWh_{el}/kg_{H2}	52.0	(ISPT, 2022)
H_2 outlet pressure	bara	5	(ISPT, 2022)
Spec. DI water demand	L/kg_{H2}	N/A	

Table 43: Technical KPIs PEM electrolysis

KPI	Unit	Value	Source
5 MW scale			
System efficiency	kWh_{el}/kg_{H2}	47.6	(Fraunhofer ISE, 2021)
H_2 outlet pressure	barg	30	(Fraunhofer ISE, 2021)
Spec. DI water demand	L/kg_{H2}	9.1	(Fraunhofer ISE, 2021)
100 MW scale			
System efficiency	kWh_{el}/kg_{H2}	48.1	(Fraunhofer ISE, 2021)
H_2 outlet pressure	barg	30	(Fraunhofer ISE, 2021)
Spec. DI water demand	L/kg_{H2}	9.1	(Fraunhofer ISE, 2021)
1 GW scale			
System efficiency	kWh_{el}/kg_{H2}	51.2	(ISPT, 2022)
H_2 outlet pressure	barg	30	(ISPT, 2022)
Spec. DI water demand	L/kg_{H2}	N/A	

Table 44: Technical KPIs SOEL electrolysis

KPI	Unit	Value	Source
1 MW scale			
System efficiency	kWh_{el}/kg_{H2}	40	(NOW, 2018)
H_2 outlet pressure	barg	12	(NOW, 2018)
Spec. DI water demand	L/kg_{H2}	N/A[39]	
10 MW scale			
System efficiency	kWh_{el}/kg_{H2}	40	(NOW, 2018)
H_2 outlet pressure	barg	12	(NOW, 2018)
Spec. DI water demand	L/kg_{H2}	N/A	
100 MW scale			
System efficiency	kWh/kg	40	(NOW, 2018)

[39] Assumption: 14 L/kgH2 Tap water quality

KPI	Unit	Value	Source
H_2 outlet pressure	barg	12	(NOW, 2018)
Spec. DI water demand	L/kg_{H2}	N/A	

Area requirements

The footprint of electrolysis plants depends on the technology type and plant configuration. In general, PEM electrolysers are characterized by a more compact design than AEL electrolysers. Therefore, PEM electrolysis plants are considered to require less area for installation compared to AEL electrolysis plants. The specific area requirement of electrolysis plants at 1 GW scale according to (ISPT, 2022) are summarized in **Error! Reference source not found.**.

Table 45: Specific area requirements of electrolysis plants (1 GW scale)

KPI	Unit	Value	Source
AEL plants	ha/MW	0.017	ISPT (2022)
PEM plants	ha/MW	0.014	ISPT (2022)

7.2.5 Ammonia synthesis

Table 46: Technical KPIs ammonia synthesis

KPI	Unit	Value	Source
TRL	-	8	(IEA, 2021)
Spec. energy consumption	MWh/t NH_3	1[40]	(IRENA, 2022)
Specific water demand	kg/t NH_3	1600[41]	(IRENA, 2022)
Operating temperature	°C	350-500	(IRENA, 2022)
Operating pressure	bar	100- 400	(IRENA, 2022)
Specific H_2 consumption	kg/kg NH_3	0.176	(IRENA, 2022)
Specific N_2 consumption	kg/kg NH_3	0.824	(IRENA 2022)

[40] Including nitrogen purification from cryogenic distillation
[41] For hydrogen production, Additional water is required for cooling and auxiliary systems.

7.2.6 Methanol synthesis

Table 47: Technical KPIs methanol synthesis

KPI	Unit	Value	Source
TRL	-	8-9	(IRENA, 2021b)
Spec. energy consumption	MWh/t MeOH	1-2[42]	(IRENA, 2021b)
Water demand	kg/t MeOH	1700[43]	(IRENA, 2021b)
Operating temperature	°C	200-300	(IRENA, 2021b)
Operating pressure	bar	50-100	(IRENA, 2021b)
Specific H_2 consumption	t/t MeOH	1.373	(IRENA, 2021b)
Specific CO_2 consumption	t/t MeOH	0.188	(IRENA, 2021b)

7.3 Appendix C: PROSUMER Tool description

PROSUMER is a modelling software which designs the optimal configuration of an energy system with the goal of minimizing carbon emissions and total cost of ownership. The software has been developed by ENGIE Impact R & D lab in collaboration with ENGIE Research as part of the EYES lab, which brings together mathematicians and energy system experts. PROSUMER software is based on a mixed-integer linear programming (MILP) algorithm. MILP allows to draft a vast amount of possible energy system configurations and select the 'best' one.

PROSUMER algorithm aims at minimizing the total cost of ownership (TCO) of an energy system, given a set of potential technologies to leverage and their corresponding techno-economical parameters. The total cost of ownership corresponds to the sum of investment costs and operational costs over all years of the project. More precisely, it corresponds to the sum of:

- Purchasing and installing the assets,
- Operation and maintenance costs,
- Fuel costs and other input commodities' costs,
- Taxes and subsidies (if applicable),
- Revenues from sale/export of commodities (negative).

Additional financial considerations: To account for time value of money, these values are discounted. To account for amortization, the remaining value of the assets at the end of the project (the salvage) is subtracted to the objective which is the TCO. Consider for example an asset whose lifetime is 30 years, while the project lifetime is 20 years. Then one third of the initial value of the asset at the end of the project is subtracted from the TCO computation. The TCO minimization must be reached under a set of constraints, accounting for the operational context of the energy system at stake. The constraints fall in the following categories:

[42] CO_2 capture not included
[43] For hydrogen production

- **Balance constraints**: The conservation of energy in the system must be ensured, meaning that for each fluid managed by the system and for each hour, over all years of the project:

$$\textit{energy production} + \textit{market supply} = \textit{energy consumption} + \textit{market resell}$$

- **Operational constraints**: Boundaries which constraint the energy to flow within the system. For example, capacity of an electric line, ramp rate of an electrolyzer, maximum energy-to-power ratio of a battery etc. Additional constraint on a minimum capacity to reserve to face eventual breakdowns or to supply ancillary markets can also be integrated.
- **Ambitions**: These are the set of objectives that one wants to reach, while minimizing the TCO. This includes for example a limit on yearly CO_2 emissions or a certain share of renewables in the energy mix.

As output, PROSUMER returns the following valuable information for each scenario simulation:

- **Asset selection**: As a result of the optimization, PROSUMER determines given all the potential energy conversion /production assets to leverage, which assets to install and which ones not to consider, in order to minimize the cost of the system while matching all the system constraints.
- **Asset sizing**: While selecting the assets to install, PROSUMER also determines the optimal size for each of them. If the demand is expected to increase during the project, it may result in investments in additional capacities within the project duration.
- **Hourly dispatch**: PROSUMER determines how much each asset will produce or consume on a hourly basis and how they will interact with each other.
- **Capacity reserved**: If required, the capacity reserved at every hour on the different assets composing the system to face eventual breakdowns or to supply ancillary markets can be calculated by PROSUMER.
- **Cashflow**: The cash flow resulting from the optimal investment strategy calculated by PROSUMER is deducted from all the costs and earnings considered.
- **Advanced KPIs**: PROSUMER allows to calculate automatically more advanced KPIs such as the levelized cost of energy or a Sankey Diagram.

It should be noted that the deployed modelling techniques and algorithms used have certain limitations. A good understanding of the algorithm as well as a strong expertise in energy systems are necessary to overcome these intrinsic limitations and allow to systematically provide relevant results.

- **Linear model:** All PROSUMER equations are linear. This means that some non-linear corelations like cost curves can only be approximated with linear formulas and need to be modelled careful and the results should be reviewed critically based on technical knowledge.
- **One hour granularity:** The lowest time granularity of PROSUMER is the hour. It is therefore not possible to model demand peaks of a few minutes in PROSUMER.
- **Grid representation:** The system is also represented as a set of equipment exchanging power in kW, PROSUMER does not represent voltage for electricity, pressure for gas or other quantities associated with flows.
- **Deterministic model:** PROSUMER is a deterministic model, which means that it assumes perfect foresight of the renewable production capacity and of the energy demand over the whole project duration.

7.4 Appendix D: Detailed site-specific results

Available for download in a separate document

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The International Hydrogen Ramp-up Programme (H2Uppp) of the German Federal Ministry for Economic Affairs and Climate Action (BMWK) promotes projects and market development for green hydrogen in selected developing and emerging countries as part of the National Hydrogen Strategy.