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Work Package 2: Modelling of scenarios for Power-to-X production in Bornholm

DTU Management
Department of Technology, Management and Economics

Danish Board of Business Development

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1 Introduction

1.1 Context

Power-to-X facilities, essentially, serve the purpose of converting electrical energy from various sources -preferably from renewable energy sources- into other forms of energy such as e-fuels. These facilities can play a vital role in indirectly electrifying hard-to-abate sectors, thereby helping on their decarbonization. The size, power sources, and technologies employed at the different units of Power-to-X plants can greatly affect their output, requiring for careful planning and optimization. This project aimed to develop an intuitive and open-source tool (OptiPlant) designed to identify an optimal size for the different Power-to-X plant components (conversion and storage units) and their operation. The tool is designed to provide fast results for a large variety of system configurations and scenarios, and also consider uncertainties.

Work package 2 (WP2) combines advanced mathematical modeling, technical PtX knowledge, resource assessment, business feasibility, and risk evaluation. High-quality input data was provided by the project partners and was incorporated into the OptiPlant model, which was the key to getting reliable results that could be used for strategic investment decisions. The sizing of the Power-to-X facilities was optimized considering local profiles for VRE (variable renewable energy) in Bornholm and techno-economic data for different energy conversion and storage technologies. Additionally, local data in terms of the availability of land and water resources, among others, were also considered to be able to assess the local private economic feasibility. This focus on Bornholm-specific data ensured that the resulting strategies and solutions were customized for the island's unique context and conditions.

1.2 Work package scope

Work Package 2 (WP2), titled 'Modelling of scenarios for Power-to-X plant', consisted of two main tasks:

- **Task 1-Development of optimization model for Power-to-X plant:** This task included all the work related to developing and enhancing the OptiPlant model such as filtering and selecting the input data, developing the model's code, improving the UX of the tool, etc. Taking all of that into account, the model was able to determine the optimal plant sizing for e-fuel production in Bornholm considering uncertainties.

- **Task 2-Model scenarios for Power-to-X production at Bornholm:** This task involved designing and scoping different relevant scenarios to be studied for the particular location of Bornholm, running the code under the respective conditions, and filtering and processing the obtained outcomes.

WP2 used techno-economical input data from the collaborating partners and Bornholm's resources potential from WP1. The optimal Power-to-X plant capacities resulting as the outcome of WP2 were used as input data of the WP4, which then could provide information about potential income from sales of services to the power grid and of sales of excess heat to the district heating system. The involved partners from all work packages also contributed to the definition/scoping of the simulated scenarios of WP2 and in the discussion of the results obtained by the OptiPlant model.

1.3 Work package outcomes

Task 1: The open-source model OptiPlant was further developed within the project such that the project partners and other parties could also use this tool as a design tool for dimensioning Power-to-X projects in other locations. The purpose of this Power-to-X feasibility tool is to go beyond research and have real-life applications for companies that can assess investment decisions based on high-quality results. In this way, the OptiPlant tool could become a key supporter of the green transition in hard-to-abate sectors, such as the shipping industry, and provide export business opportunities for companies that are active in the Power-to-X field. The tool is designed to emulate and model various scenarios for Power-to-X (PtX) facilities, considering a multitude of variable factors. More detailed information on the OptiPlant tool can be found in Section 2 of this report.

Task 2: Relevant scenarios for the feasibility assessment of a Power-to-X plant within Bornholm's context were carefully designed and selected after discussions with all the project's stakeholders. These are presented and described in detail in Section 3 For each of these scenarios, the model's outcomes including optimal plant sizing, plant operation, costs, land/water consumption, etc. were determined. These results are presented in Section 4 of this report.

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2 Optimization model for Power-to-X plant: OptiPlant

2.1 Model Description

OptiPlant is a tool initially developed by Nicolas Campion from the DTU Department of Technology, Management, and Economics that enables the user to model Power-to-X fuel production systems with a high variety of customizable input parameters and to optimize them according to different criteria. The model is presented in further detail in the articles [1] and [2].

In the standard version of the model, the Power-to-X plant is modeled using a linear deterministic programming model. Its purpose is to minimize the fuel production cost of a PtX plant by effectively managing the investments and operation of power supply, storage, and fuel production units under certain constraints. The default model assumes perfect foresight (deterministic). However, the model can also incorporate stochastic elements to account for the variability and uncertainty in renewable energy profiles.

A visual and general description of the OptiPlant model is provided in Figure 1 below:

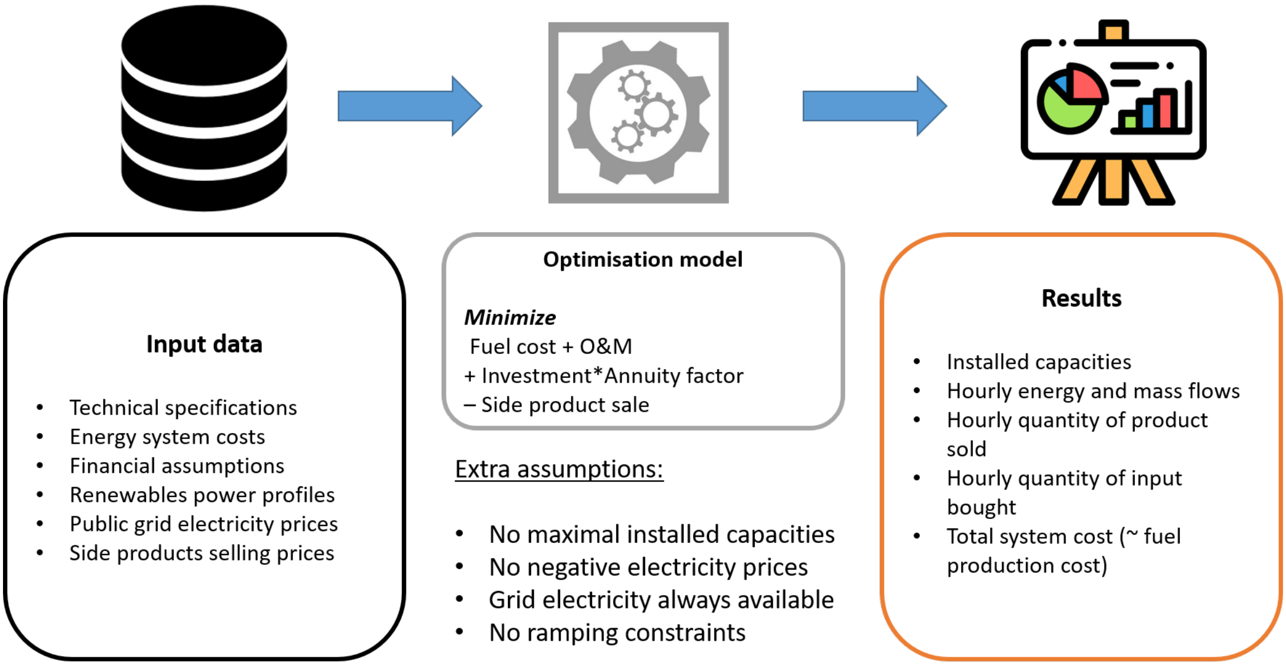

Figure 1: Overview of the OptiPlant optimization model [2]

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The model can be depicted through a simplified mathematical representation as an objective function subject to a range of constraints with a set of input data under specific assumptions [2]:

Objective function: The goal of the model is to minimize the total cost of the system (i.e. the fuel production cost).

$$\begin{aligned} Minimize \sum_{Units,Time} & FuelCost[u,t] * B[u,t] + \sum_{Units,Time} VariableOM[u] * X[u,t] \\ & + \sum_{Units} (Investment[u] * AnnuityFactor + FixedOM[u]) * Cap[u] \\ & - \sum_{Units,Time} SideProductPrice[u,t] * S[u,t] \end{aligned} \tag{1}$$

Where: *Units* refers to the different facilities of the e-fuel production system (electrolyzer, wind turbines, storage technologies, etc...). *Fuel cost* is the hourly price of electricity. *Side product price* is the hourly price of heat and oxygen. *B[u,t]* is the quantity of fuel bought at time t for the unit u. *X[u,t]* is the output mass or energy flow of the unit u at time t. *Cap[u]* is the installed capacity of unit u. *S[u,t]* is the quantity of side product sold at time t for the unit u. *B[u,t]*, *X[u,t]*, *Cap[u]* and *S[u,t]* are positive real variables.

Main constraints: The function of the model is shaped and influenced by a set of limitations and restrictions that are considered during the optimization process. The most important ones are listed below:

Load constraint: The output mass of the energy flow of each energy system unit has to stay within the operating range for each time step. For example, the ammonia or methanol plant cannot operate below 20% of the maximal capacity. The maximal load is fixed to 100% for all the units.

$$Cap[u] * Load_{min}[u] \leq X[u,t] \leq Cap[u] \qquad \forall_{u,t} \tag{2}$$

Renewable power available: Example for a specific wind profile: the output power of the wind plant is equal to the normalized power profile multiplied by the installed capacity of wind power.

$$X[u,t] = PowerProfile[u,t] * Cap[u] \qquad \forall_{t,u=WindPlant} \tag{3}$$

Fuel production constraint: The fuel plant has to produce enough e-fuel to satisfy the settled fuel demand (which can be yearly or monthly).

$$\sum_{Time} S[u,t] = Demand[u] \qquad \forall_{t,u=FuelPlant} \tag{4}$$

Other relevant restrictions for the model are mass and energy balance constraints used to regulate the flux between the different units of the fuel production plant, such as managing the intermediate storage systems (hydrogen buffer and/or batteries).

As previously mentioned, OptiPlant can operate under either a deterministic or stochastic framework regarding weather profiles. The deterministic approach, often associated with perfect foresight, assumes precise future weather parameters. Although it produces an 'ideal' solution that is theoretically optimal, it falls short in practice due to the inherent uncertainties in weather forecasting. In contrast, the stochastic method accommodates these uncertainties by utilizing probability distributions, targeting a robust solution that performs well across a spectrum of potential scenarios. Fundamental to the stochastic model's design are penalties for overproduction and underproduction of fuel. These penalties play a crucial role in determining the optimal plant size, ensuring the model accounts for the potential costs of weather-induced imbalances in production. Figure 2 below explains schematically and clearly the difference between these two approaches used in the model.

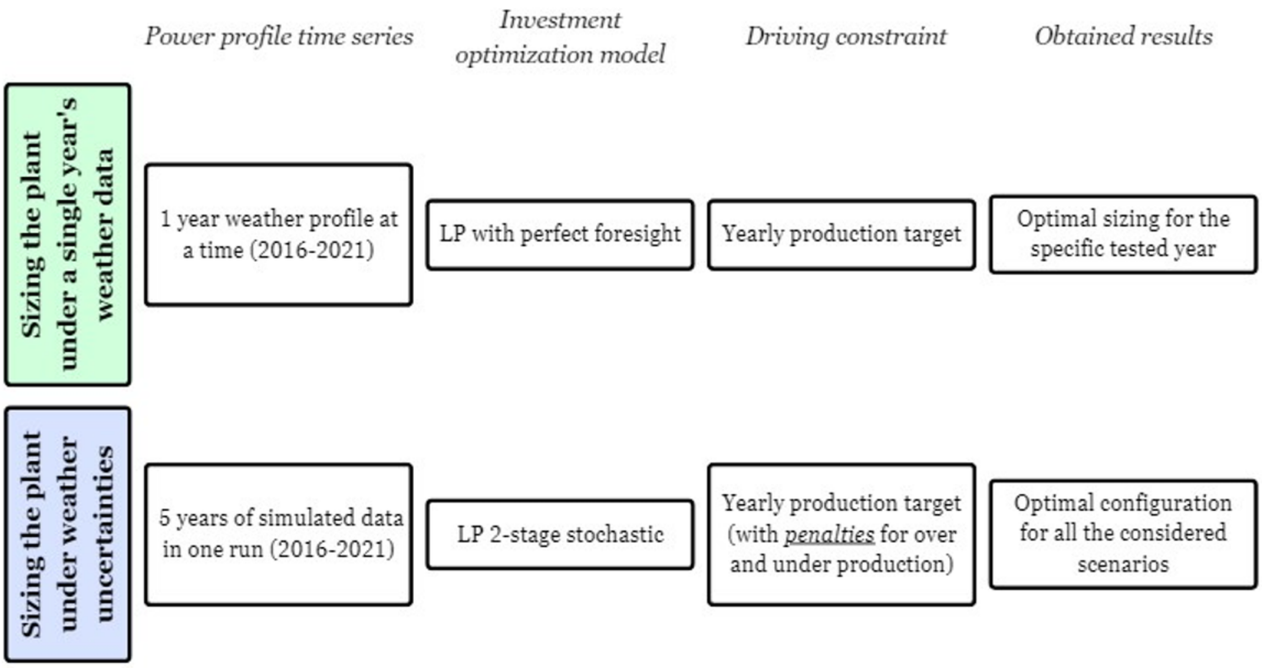

Figure 2: Scheme showing the main differences between the stochastic and deterministic model approaches.

2.2 User-guide

The key purpose of task 1 of WP2 was to further develop and refine OptiPlant. As previously mentioned, OptiPlant is an open-source and completely free tool (even the solver) that has been designed to serve not only this project, but also a broader audience with interests in Power-to-X project design and planning. That is the reason why significant efforts were put into enhancing the functionality of the tool, improving its user experience, and ensuring its utility for the project stakeholders and other parties interested in the field.

In order to facilitate an effective use of OptiPlant, a comprehensive user guide has been prepared. This guide details the process from installation to operation of the tool and can be accessed at the following link: [https://github.com/njbca/OptiPlant].

3 Technical and economic considerations for Power-to-X production at Bornholm

WP2 consisted of two essential investigations. The first one aimed at establishing key representative scenarios for the feasibility assessment of a large-scale Power-to-X plant within Bornholm's geographical context. This plant would primarily focus on producing hydrogen or ammonia, using different electrolyzer technologies. The purpose of the scenarios was to determine the optimal size for the different plant facilities and to assess the value of some important economic indicators such as the total system cost or the fuel production cost. This first analysis used both a deterministic and stochastic modeling approach for the weather profiles.

The second investigation, which is to be noted as additional research, focused on a small-scale off-grid Power-to-X plant, also based in Bornholm. This plant specializes in producing methanol and biofuel, again considering different electrolyzer technologies. The intention of this investigation was also to find the optimal plant size and the value for the two investigated economic indicators under these specific conditions.

3.1 Input data

The input data for all of the studied scenarios was drawn from various sources and extensive consultation with project partners and scientific literature. The relevant techno-economic input data used for this study (i.e. all the techno-economic characteristics for the different units/components of the PtX plants) is detailed in Table 1 and Table 2 found below. More information on the different plant units can also be found in the rest of the tables in the Appendix.

Table 1: Input Technological Assumptions for 2030

Type of units	Input/Output	Capacity	Fuel production rate	Load min	Electrical consumption
Units	-	-	kg output/kg input	% of max capacity	kWh/output
MeOH plant	H_2/MeOH	kg_{MeOH}/h	5.03[1]	20[2]	0.878[3]
NH_3 plant + ASU - AEC	H_2/NH_3	kg_{NH_3}/h	5.6[4]	20[4]	0.4[4]
NH_3 plant + ASU - SOEC	H_2/NH_3	kg_{NH_3}/h	5.6[4]	20[4]	0.6[4]
Desalination plant	-/H_2O	kg_{H_2O}/h	0	0	0.004[5]
Waste water plant	-/H_2O	kg_{H_2O}/h	0	0	0[5]
Electrolyser Park AEC	H_2O/H_2	kg_{H_2}/h	0.1[6]	0	49.8[4]
Electrolyser Park SOEC heat integrated	H_2O/H_2	kg_{H_2}/h	0.1[6]	0	37.9[7]
Electrolyser Park SOEC alone	H_2O/H_2	kg_{H_2}/h	0.1[6]	0	43.2[4]
Electrolyser Park 75AEC-25SOEC$_{HI}$	H_2O/H_2	kg_{H_2}/h	0.1[6]	0	46.8
Electrolyser Park 75AEC-25SOEC$_A$	H_2O/H_2	kg_{H_2}/h	0.1[6]	0	48.1
H_2 storage tank	H_{2in}/H_{2out}	kg_{H_2}	0	3[8]	0
H_2 storage buried pipes	H_{2in}/H_{2out}	kg_{H_2}	0	9[9]	0
Battery Park	kWh_{in}/kWh_{out}	kWh	0	0[10]	0
Pyrolysis Unit	Biomass/Bio-oil	$kg_{Bio\text{-}oil}/h$	0.11[11]	20[11]	9.2[11]
Upgrading Unit	Bio-oil/Bio-fuel	$kg_{Bio\text{-}fuel}/h$	0.64[12]	0[12]	0.098[12]
Oil Tank	$Bio\text{-}oil_{in}/Bio\text{-}oil_{out}$	$kg_{Bio\text{-}oil}$	0	0	-[13]

[1] Based on [3]. [4] refers to the value 5.3 kg output/kg input.
[2] Based on [5].
[3] At 100 bars and 220^{o}C, based on [6]. [4] refers to the value 1.7 kWh/output.
[4] Based on [4].
[5] Based on [7].
[6] Consumption of non-purified water assuming a purification efficieny of 80% based on [7]. Conversion of purified water to hydrogen is stoechiometric (9 kg of water consumed per kg of hydrogen).
[7] From [8] (assuming that heat integration performances will be similar as of 2020).
[8] Based on [9].
[9] Based on [10] assuming same values as of 2020.
[10] Based on communication with industrial partners.
[11] Based on [11].
[12] Based on [12], 0.014 kilograms of H_2 per kilogram of bio oil. This was obtained from experimental work .
[13] Based on [12], electrical consumption is included in the OPEX expenses.

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Table 2: Input Economical Assumptions for 2030

Type of units	Capacity	Investment	Fixed cost	Variable cost	Lifetime
Units	-	€/Capacity installed	€/Capacity installed/y	€/Output	years
MeOH plant	kg_{MeOH}/h	11582[1]	463[2]	0	20[3]
NH_3 plant + ASU - AEC	kg_{NH_3}/h	6662.2[4]	266.5[2]	0	30[5]
NH_3 plant + ASU - SOEC	kg_{NH_3}/h	6662.2[4]	266.5[2]	0	30[5]
Desalination plant	kg_{H_2O}/h	134.4[6]	4[7]	0.0003	20[8]
Waste water plant	kg_{H_2O}/h	107.6[9]	3.2[7]	0	15[10]
Electrolyser Park AEC	kg_{H_2}/h	39840[11]	3984[12]	0	25[3]
Electrolyser Park SOEC heat integrated	kg_{H_2}/h	39584[13]	3384.4[14]	0	25[3]
Electrolyser Park SOEC alone	kg_{H_2}/h	39584[13]	3384.4[14]	0	25[3]
Electrolyser Park 75AEC-25SOEC$_{HI}$	kg_{H_2}/h	39776	3834.1	0	25[3]
Electrolyser Park 75AEC-25SOEC$_{A}$	kg_{H_2}/h	39776	3834.1	0	25[3]
H_2 storage tank	kg_{H_2}	800[15]	24[16]	0	10[17]
H_2 storage buried pipes	kg_{H_2}	250[18]	7.5[16]	0	50[19]
OFF_SP379-HH100	kW	1998.1[20]	37.6[20]	0.0028[20]	30[20]
OFF_SP379-HH150	kW	2296.6[20]	37.6[20]	0.0028[20]	30[20]
OFF_SP450-HH100	kW	1801.4[20]	37.6[20]	0.0028[20]	30[20]
OFF_SP450-HH150	kW	2052.8[20]	37.6[20]	0.0028[20]	30[20]
Battery Park	kWh	180[21]	2.7[22]	0	25[22]
Pyrolysis Unit	$kg_{Bio\text{-}oil}/h$	13440[23]	1080[23]	0	25[23]
Upgrading Unit	$kg_{Bio\text{-}fuel}/h$	3995	799[24]	0	20[24]
Oil Tank	$kg_{Bio\text{-}oil}$	0.3[25]	0.9[25]	0	35[26]

[1] For a medium-scale 13.3 t_{MeOH}/h plant capacity based on [3], [13], [14], cost-to-capacity ratio = 0.7. [4] refers to a CAPEX of 17532€ per capacity installed.
[2] 4% Capex based on [4].
[3] Based on [15]
[4] For a large-scale 95 t_{NH_3}/h plant capacity based on [4] (includes ASU).
[5] Based on [16].
[6] Using the 2025 best value from [7].
[7] 3% Capex based on [7].
[8] Based on [17].
[9] Using the 2025 benchmark value based on [7].
[10] From WP1.
[11] From [4].
[12] Using 10% Capex based on [4].
[13] Based on [18].
[14] 8.55% Capex based on [18].
[15] Based on [16] (includes compressors).
[16] 3% Capex based on [16].
[17] For high pressure tanks, life span is around 10 years, depending on the frequency of filling/empyting. Based on [19].
[18] Based on [16] for a working pressure around 100 bars.
[19] Based on [20].
[20] From [21].
[21] From [16] assuming low lithium price.
[22] 1.5% Capex based on [16].
[23] Based on [11], bio-char as a co-product with 70% carbon. CO2 credits are about 0.10 €per kiogram of CO_2.
[24] Based on [22] and [23], high costs mainly from catalyst costs. OPEX is roughly 20% CAPEX.
[25] Based on [15] and [24], for a reserve of around 28 days at 40°C. OPEX consideres expenses from the heating system.
[26] Based on [25].

3.2 Scenario design and description

Both of the two conducted investigations are fundamental for the project and the selection of the relevant studied scenarios were the result of thorough discussions with all the project's stakeholders. These scenarios considered the following parameters: time horizon, plant scale, plant configuration, power and inputs supply type, renewable energy profiles, electrolyzer technology, type of fuel produced, the demand profile type, and the sizing method used.

Table 3 below shows the different aspects considered in the scenarios studied in both investigations (large-scale and small-scale PtX plants).

Table 3: Parameters considered when designing the different relevant scenarios explored in the two main studies of WP2 (large-scale and small-scale PtX plants)

	Large-scale PtX plant investigation	**Small-scale PtX plant investigation**
Time horizon	Projections for 2030	Projections for 2030
Plant scale	Large-scale (0.5-1 GW)	Small-scale (10-100MW)
Plant configuration	Off-grid (behind-the-meter)	Off-grid (behind-the-meter)
Power supply technologies	Offshore wind only	Wind and solar energy
Renewable energy profiles	Weather data from 2016 to 2021	Weather data from 2016 to 2021
Electrolyzer technologies	AEC, SOEC and Mix (75%AEC-25%SOEC)	AEC and SOEC
Fuel produced	Hydrogen and ammonia	Methanol and biofuel
Demand profile type	Yearly demand	Yearly demand
Sizing method	Deterministic and stochastic	Deterministic

A more detailed description of the assumptions and implications of the accounted parameters in both studies is presented in the subsequent paragraphs:

Time horizon

The year **2030** was selected as the time frame for both feasibility studies. This choice provides adequate time for planning and action. Additionally, it aligns with Denmark's aim to reduce greenhouse gas emissions by 70% by that same year. Therefore, all the techno-economic input data used in the OptiPlant model correspond to the benchmark predictions made for the year 2030.

Power-to-X plant scale

The investigation related to the **large-scale** (GW order of magnitude) PtX plant was aligned with the development plans for a 2-3 GW offshore wind energy island by 2030 in Bornholm and to exploit the potential shipping fuel market that the island may have due to its strategic geographical position. On the other hand, the secondary **small-scale** (MW order of magnitude) PtX plant study focused more on understanding Bornholm's renewable energy potential towards local self-sufficiency and autonomy, making use of the carbon sources of the island (or importing them, if necessary).

Plant configuration

In terms of plant configuration, both the large-scale and small-scale scenarios operated under a **behind-the-meter (BTM)** power supply configuration. In this setup, the Power-to-X plant is directly connected to the renewable energy supply. It is assumed that the power-to-X plant owner also owns a share of the renewable power assets that can be freely used. The BTM or off-grid configuration was the preferred one among the project stakeholders as it carries fewer economic uncertainties compared to other alternative layouts involving a grid connection to the public grid. Furthermore, this islanded configuration guarantees that the produced fuels are totally green while a grid-connected configuration cannot assure that.

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The distinct units/components of the PtX plant for each case are illustrated in the accompanying figures. Figure 3 presents the power supply and plant configuration for the large-scale investigation, while Figure 4 provides a schematic representation of the power supply and plant configuration considered in the small-scale scenario.

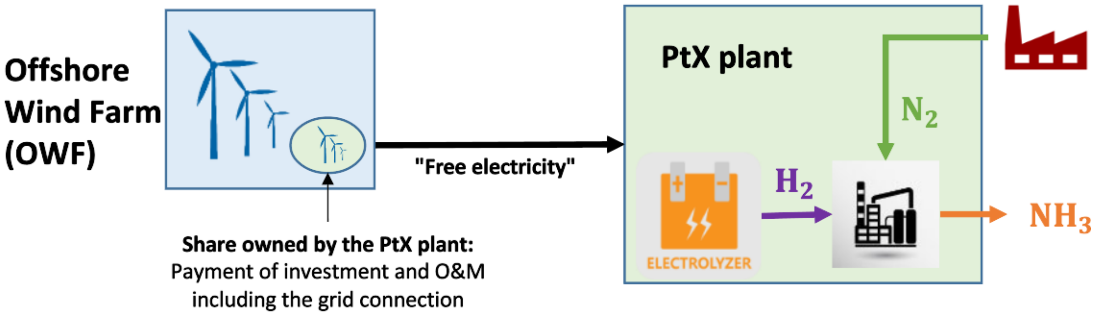

Figure 3: Scheme showing a simplified behind-the-meter (BTM) power supply configuration of the Power-to-X plant considered in the model for the large-scale study [2].

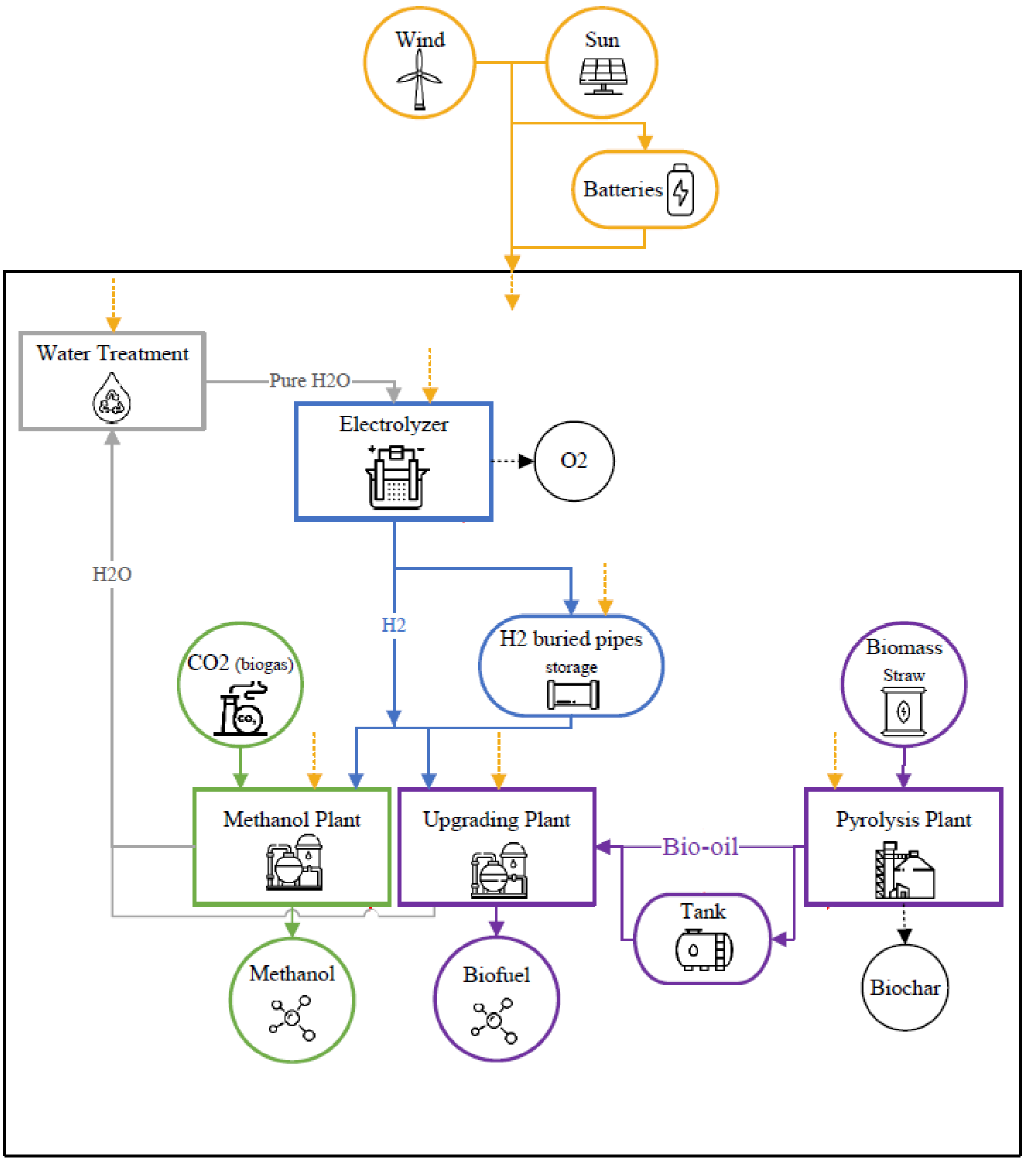

Figure 4: Scheme showing the behind-the-meter (BTM) power supply configuration of the Power-to-X plant and its main units considered in the model for the small-scale study.

Power supply technologies

As one can observe in Figure 3and 4, the simulated scenarios for the large-scale study exclusively considered **offshore wind turbines** as the power supply technology. This choice was influenced by existing plans for a large-scale offshore wind farm in Bornholm, as well as the relative lack of spatial constraints and the sociopolitical impact that onshore or inland technologies present when large-scale infrastructures are needed. On the other hand, the supplementary small-scale study encompassed a more diverse power supply configuration, integrating both **solar photovoltaic (PV)** and **wind turbines (onshore and offshore)**. This choice allowed for a more detailed investigation of smaller-scale operations, which could feasibly involve multiple power sources.

Renewable energy profiles

The studied scenarios integrated wind and solar profiles from the vicinity of the island of Bornholm. The available profiles spanned from the year **2016 until 2021** and were obtained using the CorRes tool [26]. Individual year's data was used for the deterministic studies, while a combination dataset including all years was used for the stochastic simulations.

Electrolyzer technologies

Three different electrolyzer technologies/configurations were considered when modeling the large-scale Power-to-X plant: Alkaline Electrolyzer Cells **(AEC)**, Solid Oxide Electrolyzer Cells **(SOEC)**, and a combination of 75% AEC + 25% SOEC electrolyzer **(Mix)**. As previously mentioned, the techno-economic characteristics used for the electrolyzers in the model are collected in the tables in the Appendix. Each of these technologies has upsides and downsides from a techno-economic standpoint. For instance, AEC has lower capital cost compared with SOEC, but SOEC is characterized to perform with higher efficiency due to its high operating temperature, therefore decreasing the operational electricity required. Additionally, the efficiency of the electrolyzers is found to depend on the load, see more in the load curve also included in the Appendix. The representation of the load has been included in the model with a piece-wise linearization approach. However, after conducting the analysis, it was observed that the variation in efficiency with load had minimal effect on the overall results. Consequently, for simplicity and practicality, it was decided to treat the efficiency as approximately constant for the different scenarios, yielding consistent results without compromising the accuracy of the model.

Fuel produced

As previously mentioned, the investigations were focused on different types of fuel production. The study concerning the large-scale Power-to-X plant was centered around the production of hydrogen and ammonia. In contrast, the small-scale Power-to-X plant study was designed to produce methanol and biofuel through pyrolysis and upgrading processes. The techno-economic characteristics used for the different units involved in the fuel production for each of the studied scenarios are included in the tables in the Appendix.

Fuel demand type

The fuel demand projected in these studies is on an **annual basis**. More specifically, in the primary study focused on the large-scale PtX plant, the fuel demand for hydrogen is set to be 66kt/year and the demand for ammonia is projected at 426kt/year. This corresponds to approximately 2200 GWh of fuel.

To understand the magnitude of 2200 GWh of fuel, it's helpful to roughly compare this figure with the energy consumption in different sectors of Bornholm, as detailed in the Bornholm Energy Strategy [27]. For instance, the local industry in Bornholm is estimated to use process energy equivalent to approximately 18.5 GWh/y. The heavy transportation on Bornholm (vans, trucks, bus services, and farming machines) uses energy equivalent to 155 GWh/y of energy ca. The demand for Bornholm's ferry company is around 237GWh/y. In all three cases, the consumption represents only a fraction of the projected fuel production. Finally, taking into account all the vessel segments in the Baltic Sea, these ships consume a total of 4,360,000 tons of fuel, equivalent to approximately 43600 GWh of energy. The energy produced by the PtX plant, amounting to 2200 GWh, could meet around 5% of this demand.

On the other hand, the secondary study revolving around the small-scale PtX plant included two demand approaches for methanol and biofuel. These approaches were differentiated by the availability of CO2. In the first case, the availability of CO2 was limited to the amount locally produced in Bornholm (20kton CO2/year), resulting in fuel demands of 13.3 kton/y of methanol and 7.9 kton/y of biofuel. This production could supply 31% of the fuel demand of Bornholm's ferry company. The second case allowed for the possibility of importing additional CO2 from abroad, resulting in a fuel demand that was 125 kton/y of methanol and 75 kton/y of biofuel (approx. 10 times greater than the first approach). The sizing of this second installation, arises from Danish Power-to-X perspectives [28], [29], [30] and Bornholm objectives on P2X plants (WP1).

In both investigations, no constraints related to the storage or transport of the produced e-fuel were considered by the model.

Sizing method

As previously described, the model can operate and process the weather data in two ways: deterministic and stochastic. In the deterministic approach, a single year's weather data is used for the sizing of the Power-to-X plant, providing insights into plant performance under specific weather conditions. On the other hand, the stochastic approach accounts for weather variability and uncertainty by using multiple years of weather data for plant sizing, thus offering a wider perspective on plant design and performance under diverse weather scenarios. In the large-scale investigation, both the deterministic and stochastic sizing methods were used, while in the small-scale secondary investigation, only the deterministic approach was applied.

3.3 Resulting scenarios

The different combinations of all the considered aspects mentioned above resulted in a set of unique scenarios that were thoroughly examined in both investigations. For instance, in the large-scale PtX plant investigation, **36 deterministic scenarios** and **6 stochastic scenarios** were run through the model. For the deterministic case, these number arises from the combination of 6 weather years' data (2016 to 2021), 3 types of electrolyzer (AEC, SOEC, Mix), and 2 types of produced fuel (H2 and NH3). On the other hand, for the stochastic case it originates from combining 1 run of all the weather years (2016 to 2021), 3 types of electrolyzer (AEC, SOEC, Mix), and 2 types of produced fuel (H2 and NH3).

In regards to the small-scale PtX plant investigation, **8 deterministic scenarios** were examined. This number comes from the combination of 1 weather year data (2018), 2 types of electrolyzer (AEC, SOEC), 2 types of produced fuel (Methanol and biofuel), and 2 types of CO2 availability limits (local and local+import).

The study of all these scenarios provides a comprehensive analysis of the feasibility and potential of Power-to-X technology in Bornholm under various conditions and configurations. The exploration of these scenarios was critical to understanding the holistic implications of different power sources, technologies, plant scales, and fuel types for the island's energy future. The obtained results for these scenarios are presented in the following section.

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4 Results and discussion

This section presents and discusses the outcomes derived from the simulation of all the designed and selected scenarios using the OptiPlant tool. The results are divided into two main categories: the outcomes derived from the large-scale PtX plant study and the ones from the small-scale PtX supplementary investigation.

As outlined in previous sections, for the large-scale PtX, we conducted both deterministic and stochastic analyses. In contrast, the small-scale study was approached using only a deterministic analysis. Each subsection provides details on the optimal plant sizing for each case. In some of the analyses, economic indicators and/or resource availability assessments are also included if considered relevant.

In conjunction, all these analyses provide valuable insights into the feasibility of implementing a Power-to-X project in Bornholm, whether on a large scale primarily focused on hydrogen and ammonia production, or on a small scale primarily dealing with methanol and upgraded pyrolysis biofuel.

4.1 Large-scale PtX plant study: hydrogen and ammonia production

This investigation aimed at analyzing the feasibility and implications of a large production of hydrogen and ammonia in Bornholm. Considering the substantial wind energy resources of the island, this study explored various scenarios and configurations to optimize the production cost, plant size, and resource utilization. The results shown below provide key insights into the potential of Bornholm to emerge as a significant contributor to the renewable hydrogen and ammonia market, given the potential market demand for these fuels on the island.

4.1.1 Deterministic analysis: Plant sizing based on a single year's weather data

This subsection explores the deterministic approach to sizing the Power-to-X plant, which uses a single year's weather data -i.e. wind profiles-. As previously mentioned, a total of 36 distinct scenarios were simulated for this analysis, representing a combination of six different weather years, three electrolyzer plant configurations, and two produced types of fuel. However, to concisely address the impact of weather fluctuations on plant sizing, only the results for three analyses were presented and named accordingly as minimum (best year case), maximum (worst year case), and average (typical case).

These selected scenarios - minimum, maximum, and average - were identified based on key performance indicators optimized by the model: fuel production cost and total system cost. The minimum (best case) and maximum (worst case) years, corresponding to the years 2017 and 2018 respectively, represent the extreme sizing and operation situations. For each of these years, six specific scenarios (arising from the combination of the two types of produced fuels and the three electrolyzer configurations) are analyzed. In addition to this, an average year scenario was chosen to be represented by the year 2020, which is closest to the average of all six years' data (2016 to 2021), rather than choosing an artificial construct of an average year. This approach provides a more realistic representation of a typical year in terms of weather conditions and their impact on the plant. Finally, it is important to reiterate that all techno-economic input data utilized through all the analysis corresponds to predictions made for the year 2030.

The results of the deterministic analysis consist of two parts. First, the optimal plant sizing for the selected scenarios and the cost analysis under the given weather conditions are presented. Secondly, a water availability study is included as this resource is critical for the Power-to-X plant operation.

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Optimal Power-to-X plant sizing and cost analysis for specific weather years

The optimal sizing of the different Power-to-X plant units for the mentioned representative scenarios (best-case year, worst-case year, average/typical year) is provided in Table 4.

Table 4: Optimal sizing of the large Power-to-X plant units for different scenarios under the deterministic analysis (H2 and NH3)

	H2-AEC	**H2-SOEC**	**H2-MIX**	**NH3-AEC**	**NH3-SOEC**	**NH3-MIX**
Offshore Wind Farm [1] [MW]						
Best-case year (2017)	725.5	629.4	701.4	897.7	714.2	862.2
Worst-case year (2018)	850.5	738.8	822.5	1054.2	847.1	1015.4
Typical/average year (2020)	753.7	653.9	728.8	938.3	747.4	900.2
Electrolysis plant [MW]						
Best-case year (2017)	688.8	597.5	666.0	796.3	683.9	767.5
Worst-case year (2018)	799.5	692.1	772.8	911.3	775.4	874.9
Typical/average year (2020)	715.6	620.8	691.9	818.2	700.3	788.7
Wastewater treat. plant [m3 H2O/h]						
Best-case year (2017)	158.4	158.4	158.4	183.1	181.3	182.5
Worst-case year (2018)	183.9	183.5	183.8	209.6	205.5	208.1
Typical/average year (2020)	164.6	164.6	164.6	188.2	185.7	187.6
NH3 prod. plant (+ ASU) [t NH3/h]						
Best-case year (2017)	*	*	*	76.7	76.0	76.7
Worst-case year (2018)	*	*	*	85.0	82.6	84.4
Typical/average year (2020)	*	*	*	75.5	74.7	75.3
Batteries [MWh]						
Best-case year (2017)	*	*	*	219.0	297.9	295.3
Worst-case year (2018)	*	*	*	320.2	415.8	422.0
Typical/average year (2020)	*	*	*	410.7	540.7	541.8
H2 storage (buried pipes) [t]						
Best-case year (2017)	*	*	*	194.1	183.6	192.7
Worst-case year (2018)	*	*	*	312.0	304.7	311.9
Typical/average year (2020)	*	*	*	335.8	330.7	337.1

[1] The model selected the SP379-HH150 turbine as the optimal choice from the available catalogue.

For this particular analysis, the fuel production cost and total system cost for each of the selected relevant scenarios were also examined. Figures 5, 6, and 7 provide a graphical representation of these economic indicators for the best-case year (2017), the worst-case year (2018), and the average/typical year (2020), respectively. Each figure depicts the cost outcomes for the six specific scenarios derived from the combination of the two types of produced fuels and the three electrolyzer configurations within each year. In these figures, each scenario is represented by a stacked bar indicating the total annualized cost in M€ (million euro), broken down by the cost of the different plant units on the primary y-axis. The corresponding fuel production costs are represented by black dots plotted on the secondary y-axis in €/MWh. The numerical values annotated above each dot specify the fuel production costs, both in terms of €/MWh and €/kg.

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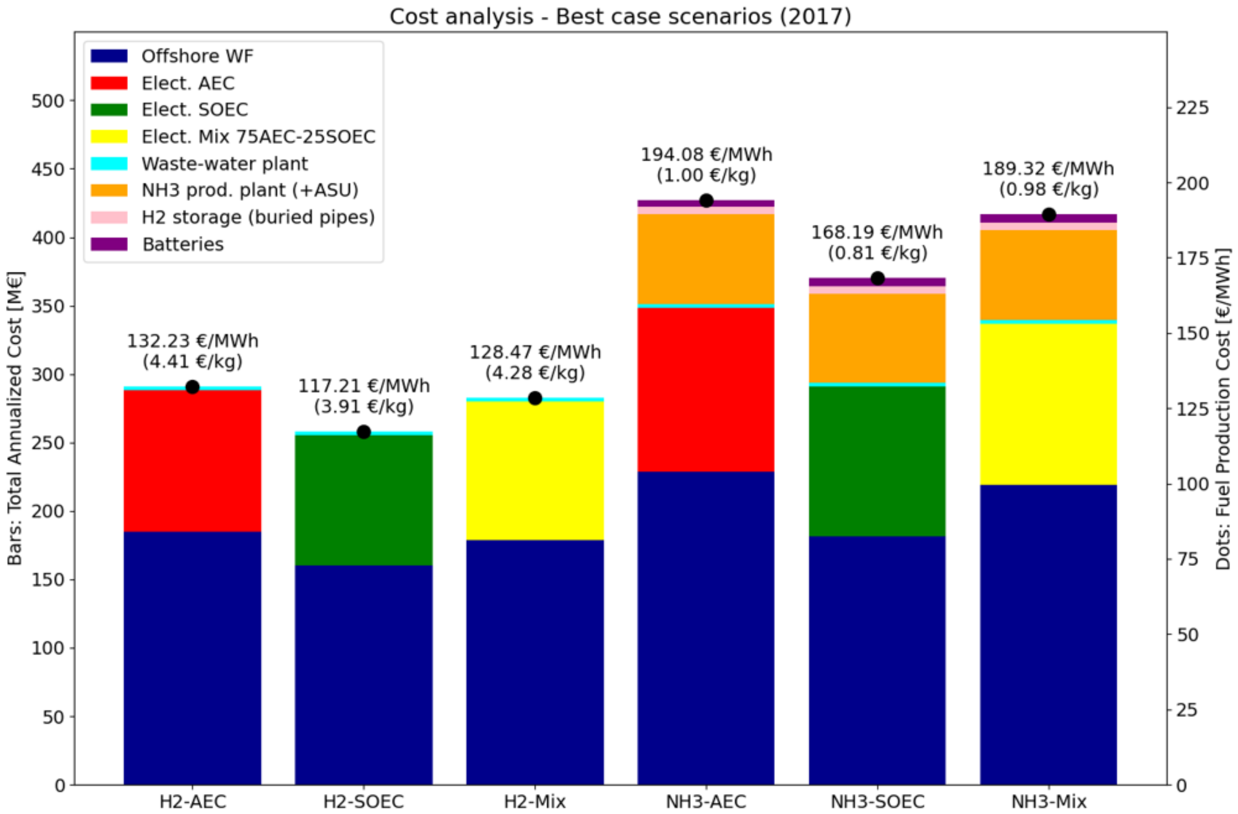

Figure 5: Comparative cost analysis for the scenarios of the best-case weather year -i.e. minimum costs- (2017). Main study.

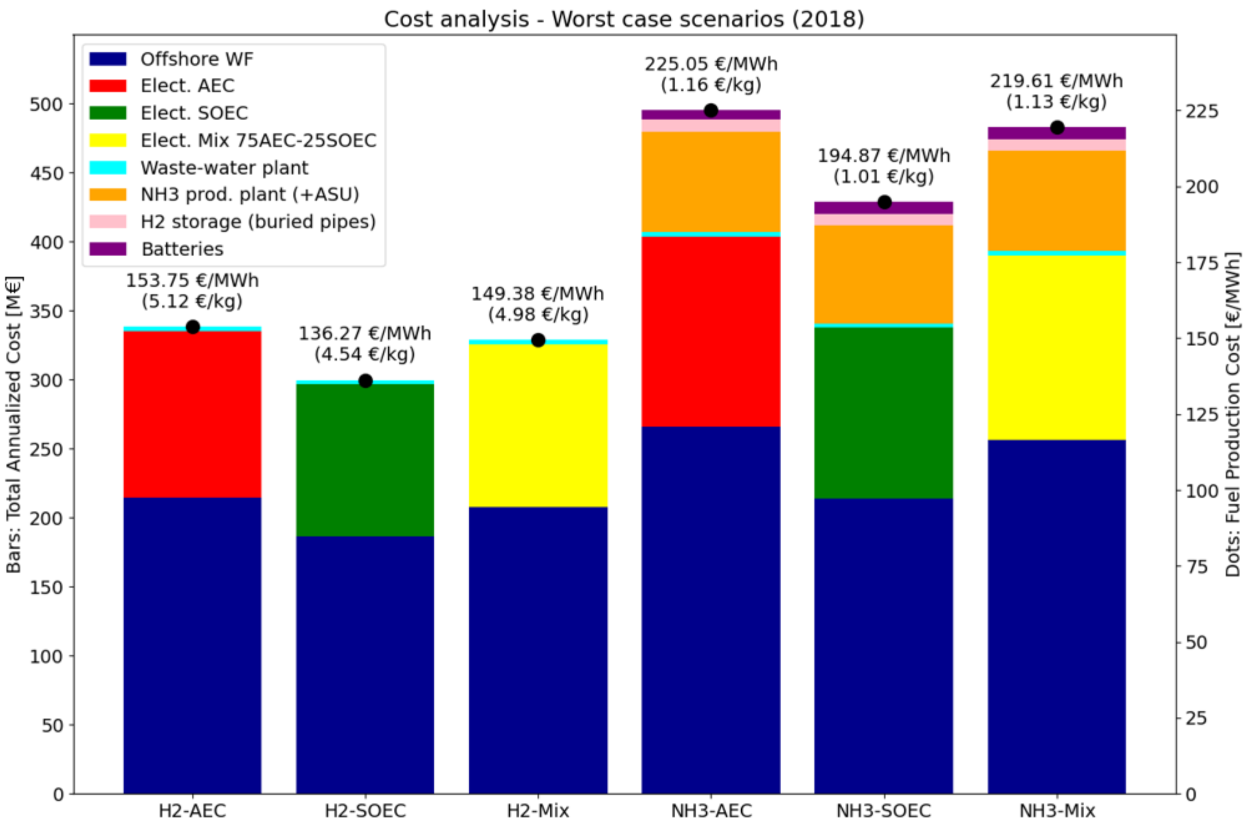

Figure 6: Comparative cost analysis for the scenarios of the worst-case weather year -i.e. maximum costs- (2018). Main study.

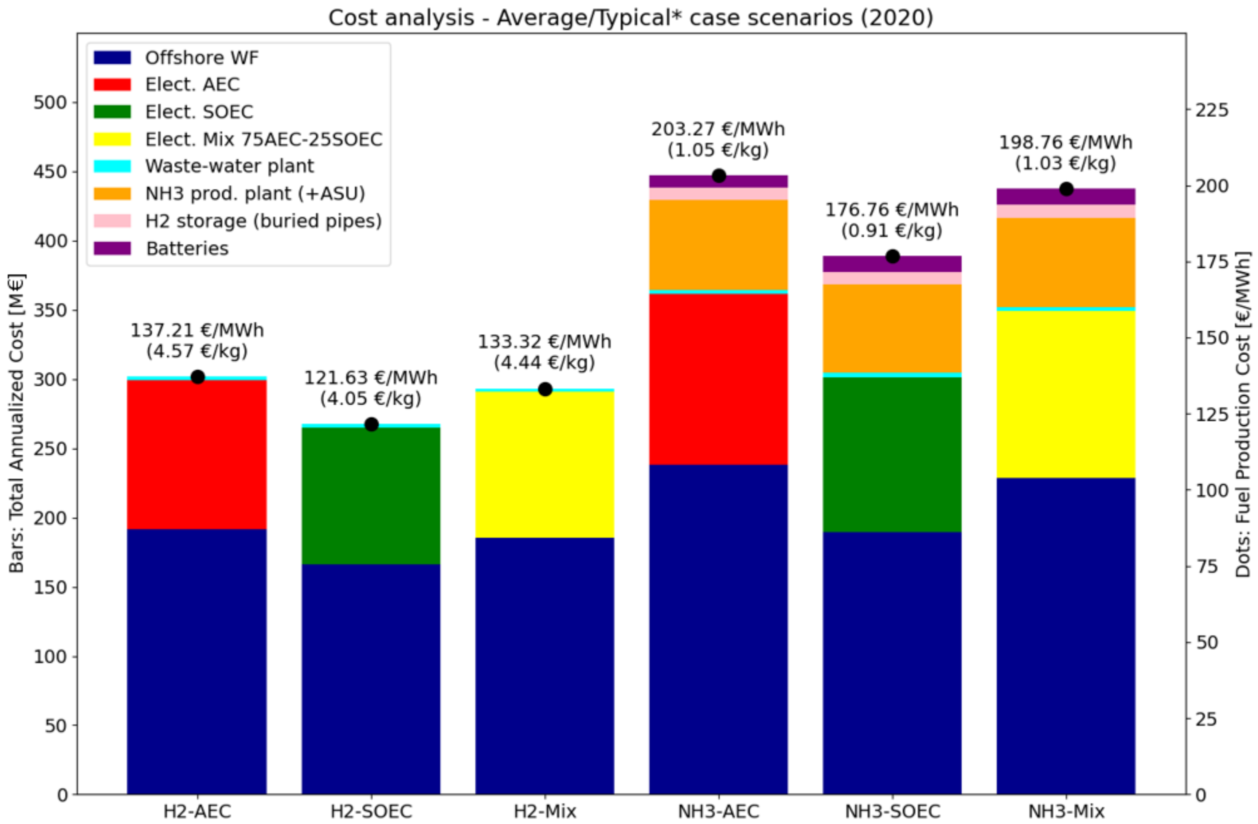

Figure 7: Comparative cost analysis for the scenarios of the average/typical weather year (2020). Main study.

In addition to the graphs shown above, Table 5 provides a numerical summary of the total system cost and Table 6 of the fuel production cost for all the scenarios within the best-case, worst-case, and average/typical years. This allows for a quick reference and a more clear visualization of the costs of the different plant configurations under various weather conditions.

Table 5: Breakdown of the total system cost of the large Power-to-X plant by unit for different scenarios under the deterministic analysis (H2 and NH3) - all costs are in [M€].

	H2-AEC	H2-SOEC	H2-MIX	NH3-AEC	NH3-SOEC	NH3-MIX
Offshore Wind Farm						
Best-case year (2017)	184.53	160.09	178.42	228.34	181.67	219.31
Worst-case year (2018)	214.78	186.55	207.70	266.20	213.92	256.40
Typical/average year (2020)	191.35	166.01	185.02	238.22	189.75	228.55
Electrolysis plant						
Best-case year (2017)	103.87	95.26	101.72	120.08	109.03	117.21
Worst-case year (2018)	120.56	110.35	118.03	137.42	123.61	133.65
Typical/average year (2020)	107.91	98.97	105.68	123.39	111.68	120.49
Wastewater treat. plant						
Best-case year (2017)	2.51	2.51	2.51	2.90	2.87	2.89
Worst-case year (2018)	2.90	2.89	2.90	3.31	3.24	3.28
Typical/average year (2020)	2.60	2.60	2.60	2.98	2.94	2.97
NH3 prod. plant (+ ASU)						
Best-case year (2017)	*	*	*	65.66	65.07	65.53
Worst-case year (2018)	*	*	*	72.75	70.72	72.24
Typical/average year (2020)	*	*	*	64.62	63.93	64.49
Batteries						
Best-case year (2017)	*	*	*	4.61	6.26	6.21
Worst-case year (2018)	*	*	*	6.74	8.74	8.87
Typical/average year (2020)	*	*	*	8.64	11.37	11.40
H2 storage (buried pipes)						
Best-case year (2017)	*	*	*	5.42	5.13	5.38
Worst-case year (2018)	*	*	*	8.72	8.51	8.71
Typical/average year (2020)	*	*	*	9.38	9.24	9.42
TOTAL						
Best-case year (2017)	290.90	257.86	282.64	427.00	370.03	416.53
Worst-case year (2018)	338.24	299.79	328.63	495.14	428.75	483.17
Typical/average year (2020)	301.87	267.58	293.29	447.22	388.90	437.31

Table 6: Fuel production cost of different scenarios under the deterministic analysis (H2 and NH3)

	H2-AEC	H2-SOEC	H2-MIX	NH3-AEC	NH3-SOEC	NH3-MIX
Fuel production cost [€/MWh]/[€/kg]						
Best-case year (2017)	132.33/4.41	117.21/3.91	128.47/4.28	194.08/1.00	168.19/0.87	189.32/0.98
Worst-case year (2018)	153.75/5.12	136.27/4.54	149.38/4.98	225.05/1.16	194.87/1.01	219.61/1.13
Typical/average year (2020)	137.21/4.57	121.63/4.05	133.32/4.44	203.27/1.05	176.76/0.91	198.76/1.03

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Assessment of the availability of water resources

The deterministic analysis of Power-to-X plant operation requires a comprehensive understanding of the available resources, one of the most critical being water. More specifically, this availability assessment considered treated wastewater as the water source for the Power-to-X plant. This choice was motivated by the high availability of wastewater on the island of Bornholm and its lower cost compared to other potential water sources. Furthermore, using the available wastewater on the island would not interfere with other sectors, as this resource is not generally utilized for other purposes.
The focus of this section is to test the system's resilience under the 'maximum water demand' conditions derived from the previously studied scenarios. These conditions of maximum demand correspond to the needs required for the production of ammonia, which requires 0.8626 million m3 of water annually. To provide an accurate representation, the water demand was evaluated on an hourly basis throughout the year. The extreme conditions studied combine the peak demand of each month from all the ammonia scenarios. This approach ensures that the water supply would be adequate under all potential operational conditions, by examining its feasibility under the most stringent demands.

The available monthly wastewater quantities from the different wastewater treatment plants in Bornholm for the year 2021 were extracted from the WP1 report. For reference, these amounts are tabulated in the following Table 7:

Table 7: Available wastewater from different water treatment plants in Bornholm (2021)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Rønne [m3]	312000	255000	287000	218000	213000	154000	160000	181000	190000	185000	308000	431000
Nexø [m3]	145000	122000	124000	87000	84000	43000	64000	67000	75000	77000	158000	200000
Boderne [m3]	163000	123000	138000	76000	80000	34000	53000	63000	53000	52000	143000	201000
Tejn [m3]	114000	68000	87000	50000	57000	31000	54000	45000	35000	47000	76000	137000
Svaneke [m3]	80000	54000	62000	40000	48000	19000	29000	27000	31000	38000	63000	95000
Melsted [m3]	23000	13000	17000	9000	13000	5000	12000	11000	8000	9000	15000	25000

The 'maximum water demand' from the Power-to-X plant for the different months throughout the year is detailed in Table 8 below:

Table 8: Maximum water demand for the large Power-to-X plant under the deterministic analysis (H2 and NH3)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
[m3]	112106	95945	76807	91360	68126	82311	54520	65951	80930	99202	78916	96052

For a more visual comparison of the available water from wastewater treatment plants in Bornholm and the water demand of the Power-to-X plant, a comparative graph is provided in Fig.8. In this graph, the monthly wastewater production of different plants in Bornholm for the year 2021 (Table 7) is represented as individual bars, offering a clear distinction between the plants. On top of that, the 'maximum water demand' from the PtX plant (Table 8) is represented as a black line. Furthermore, a hypothetical 'doubled maximum water demand' is also represented as a dotted red line, illustrating potential future demands or stress scenarios on the water supply.

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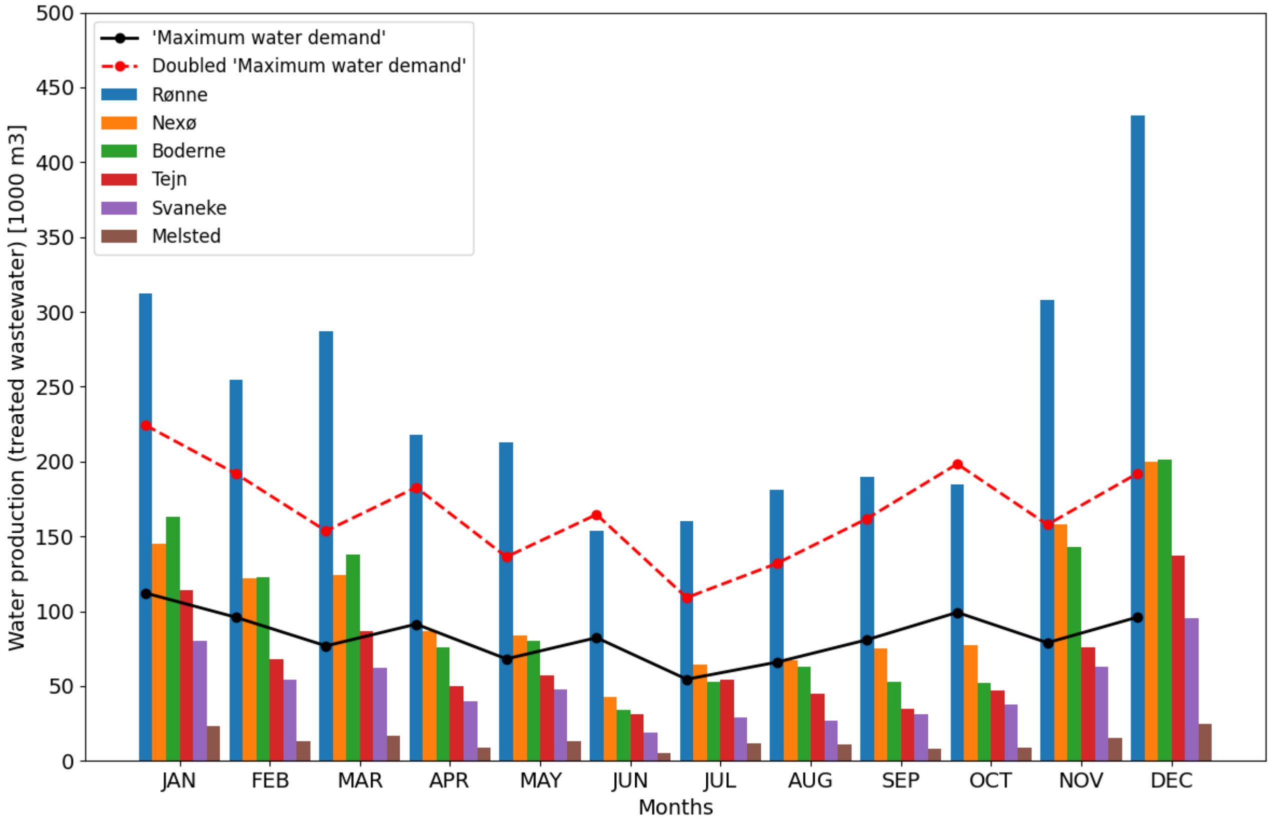

Figure 8: Monthly wastewater production from different treatment plants in Bornholm for 2021 compared with the 'maximum water demand' of the Power-to-X plant (black line) and a hypothetical 'doubled maximum water demand' scenario (dashed red line).

Export costs: Hydrogen transport via pipeline to Germany

The potential of exporting hydrogen from Bornholm to neighboring countries was also investigated, taking into account infrastructure and associated costs.

The yearly hydrogen production of 66ktH_2 in the proposed electrolyzer equals an average production of 0.25 GW of hydrogen and a peak production of 0.45 GW. To determine the appropriate capacity of the offshore underground pipeline for hydrogen transportation, two sizes were initially considered: medium ($\sim$ 900 mm) and large ($\sim$ 1200 mm). The capacity of the pipelines highly depends on the operating pressure and can reach 18 GW and 37.2 GW respectively [31], but EHB suggests operating them at 7 GW and 13 GW respectively to optimize costs [32]. The pipelines in question are not a limiting factor for the proposed hydrogen production on Bornholm, but would be influenced by the combined future hydrogen production in the Baltic Sea.

A study from EHB, [33], provides estimates for offshore hydrogen pipeline costs. The estimated cost for transporting hydrogen through underground offshore pipelines in Europe is approximately 0.17-0.32 €/kgH2 per every 1000 km. This estimate includes both new and repurposed pipelines, where a connection from Bornholm to Germany will likely be a new pipeline. For new offshore pipelines, the cost of transportation is 0.32-0.60 €/kgH2/1000km depending on the size of the pipeline.

The concept of transporting hydrogen from Bornholm to the northern part of Germany has already been explored by various developers. As part of the collaboration between GASCADE and Copenhagen Infrastructure Partners (CIP), a 140-km hydrogen pipeline connecting Bornholm to Lubmin, Germany, is set to be commissioned and begin operation in 2027. It will have an import capacity of 10GW, with plans to potentially extend it to 20GW [34].

The cost of transporting hydrogen through this pipeline will likely be around **0.60 €/kgH2/1000km** considering that it will initially be a medium-sized, new hydrogen pipeline. However, this estimation is uncertain as hydrogen infrastructure is still an evolving technology and the pipeline financing is dependent on future investment in hydrogen in the Baltic Sea.

Conclusions

The deterministic analysis of the Power-to-X plant, based on a single year's weather data, has provided insights into the various factors that influence the plant's sizing, costs, and operational considerations. The main conclusions drawn from this investigation include:

• **Total system costs:** The study has revealed that producing hydrogen has lower total system costs compared to ammonia. The simplicity of the hydrogen PtX plant design contributes to reduced costs for hydrogen production, while the production of ammonia demands investment in storage solutions such as batteries and hydrogen pipes. This is due to the increased complexity of the system and the need to optimize the operation of the ammonia production plant. It is important to note that the need for hydrogen storage in the ammonia production process appears due to the plant's operational constraints, specifically the minimum load requirement (20% of max capacity).

• **Fuel production costs:** The results show that producing hydrogen has cheaper production costs compared to ammonia (both in terms of €/MWh and €/kg). The obtained fuel production prices for the 'best case' in the OptiPlant model are 3.91€/kg of H2 and 0.81€/kg of NH3. The International Energy Agency (IEA) predicts that the production costs for these fuels, in 2030 in Western Europe using VRE, would range between 1.03-3.25€/kg for H2 and between 0.747-0.936€/kg for NH3 [35] [36]. The higher fuel production costs obtained in our study could be due to different factors. One reason could be our reliance on exclusively offshore wind energy, which has a low capacity factor. Another possibility is that we made different assumptions in our model compared to others. Nonetheless, our estimated prices align closely with the IEA's projections, highlighting the potential for e-fuel production in Bornholm.

• **Optimal electrolyzer technology:** Taking into account the techno-economic data predictions for 2030, the solid oxide electrolysis cell (SOEC) emerges as the most cost-effective option among the electrolyzer technologies examined for both producing hydrogen and ammonia.

• **Major cost components of the plant:** The offshore wind farm (OWF) and the electrolyzers constitute the most substantial portions of the system's overall costs for all studied scenarios. This indicates a vital area for potential cost optimization.

• **Co-products selling opportunity:** It is important to note that the provided numbers for the costs don't take into account the potential revenue that can be made from selling some co-products of the plant processes such as heat or oxygen. This could have a significant impact on the final cost of the system and the fuel. The sale of these co-products was not included in this part of the study due to the high uncertainties related to their market prices, demand dynamics, production volumes, or considerations that were outside the scope of this particular work package.

• **Weather impact on costs and stochastic sizing:** A substantial difference in costs is observed between good and bad weather years, demonstrating the huge impact weather has in both the fuel production and total system costs. This fact underscores the necessity to use stochastic analysis when sizing the plant, as it considers weather uncertainty across multiple years, being a more robust approach.

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• **Water supply consideration:** The availability assessment of water resources emphasizes that the Rønne wastewater treatment plant is the only one on the island that can easily meet the maximum water demand of the Power-to-X plant. In fact, the sensitivity analysis showed that almost during all months of the year, this plant can supply double the maximum demand, ensuring robust system resilience.

• **Potential for export:** The explored concept of transporting hydrogen to Germany, along with the associated infrastructure and costs, adds an essential layer to the analysis, emphasizing the wider market potential and the strategic positioning of Bornholm.

4.1.2 Stochastic analysis: Plant sizing under weather uncertainty

This subsection aims to account for the inherent unpredictability in weather patterns -i.e. variability in wind speed- by using stochastic analysis. This methodology considers a multitude of weather scenarios over several years, as opposed to a single year's weather data. In the stochastic analysis, the weather data from the years 2016 to 2021 was leveraged to generate a run that combines all the years, representing a more comprehensive set of potential operating conditions the Power-to-X plant might face throughout its lifetime. This provides a more robust estimate of the optimal plant sizing, which is crucial for informed long-term planning and investment decisions in Power-to-X projects.

While the deterministic analysis focuses on specific weather years, the stochastic analysis uses the data of the combination of all years in the same model run for a more comprehensive view of potential operating conditions. Thus, a total of 6 scenarios arising from the combination of the two types of produced fuels and the three electrolyzer configurations were explored under the generated stochastic wind profile. Again, it is important to note that all techno-economic input data utilized through all the analysis corresponds to predictions made for the year 2030.

The presented results primarily focus on determining the optimal plant size under weather variability, a fundamental step for effective Power-to-X plant planning and design. Given that the size found through the stochastic approach is considered to be the most suitable for actual plant construction, it is crucial to also assess land resource availability based on these optimal sizes. Thus, land resource availability is also examined within this context due to its significant influence on plant feasibility. However, it is essential to understand that certain factors, such as costs, can be more accurately derived from deterministic data. This is due to the inherent design of the stochastic model, which incorporates penalties for overproduction and underproduction. These penalties guide the plant sizing in the stochastic approach.

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Optimal power-to-X plant sizing under weather uncertainty

The optimal sizing outcomes for the Power-to-X plant components, corresponding to the selected scenarios from stochastic analysis using weather data from 2016 to 2021, are summarized in Table 9. For comparison, the sizing data from the deterministic analyses, previously presented, is also included in Table 9.

Table 9: Optimal sizing of the large Power-to-X plant units for different scenarios under the stochastic analysis (H2 and NH3) -deterministic results also inclued in italics for comparison-

	H2-AEC	H2-SOEC	H2-MIX	NH3-AEC	NH3-SOEC	NH3-MIX
Offshore Wind Farm [1] [MW]						
Stochastic 2016-2021	706.4	613.8	683.2	910.1	733.9	879.3
Deterministic: typical year (2020)	*753.7*	*653.9*	*728.8*	*938.3*	*747.4*	*900.2*
Deterministic: best case year (2017)	*725.5*	*629.4*	*701.4*	*897.7*	*714.2*	*862.2*
Deterministic: worst case year (2018)	*850.5*	*738.8*	*822.5*	*1054.2*	*847.1*	*1015.4*
Electrolysis plant [MW]						
Stochastic 2016-2021	667.9	578.2	645.4	782.7	661.6	750.6
Deterministic: typical year (2020)	*715.6*	*620.8*	*691.9*	*818.2*	*700.3*	*788.7*
Deterministic: best case year (2017)	*688.8*	*597.5*	*666.0*	*796.3*	*683.9*	*767.5*
Deterministic: worst case year (2018)	*799.5*	*692.1*	*772.8*	*911.3*	*775.4*	*874.9*
Wastewater treat. plant [m3 H2O/h]						
Stochastic 2016-2021	153.6	153.3	153.5	180.0	175.4	178.5
Deterministic: typical year (2020)	*164.6*	*164.6*	*164.6*	*188.2*	*185.7*	*187.6*
Deterministic: best case year (2017)	*158.4*	*158.4*	*158.4*	*183.1*	*181.3*	*182.5*
Deterministic: worst case year (2018)	*183.9*	*183.5*	*183.8*	*209.6*	*205.5*	*208.1*
NH3 prod. plant (+ ASU) [t NH3/h]						
Stochastic 2016-2021	*	*	*	69.5	67.5	68.6
Deterministic: typical year (2020)	*	*	*	*75.5*	*74.7*	*75.3*
Deterministic: best case year (2017)	*	*	*	*76.7*	*76.0*	*76.7*
Deterministic: worst case year (2018)	*	*	*	*85.0*	*82.6*	*84.4*
Batteries [MWh]						
Stochastic 2016-2021	*	*	*	417.2	583.7	541.8
Deterministic: typical year (2020)	*	*	*	*410.7*	*540.7*	*541.8*
Deterministic: best case year (2017)	*	*	*	*219.0*	*297.9*	*295.3*
Deterministic: worst case year (2018)	*	*	*	*320.2*	*415.8*	*422.0*
H2 storage (buried pipes) [t]						
Stochastic 2016-2021	*	*	*	459.4	438.8	452.1
Deterministic: typical year (2020)	*	*	*	*335.8*	*330.7*	*337.1*
Deterministic: best case year (2017)	*	*	*	*194.1*	*183.6*	*192.7*
Deterministic: worst case year (2018)	*	*	*	*312.0*	*304.7*	*311.9*

[1] The model selected the SP379-HH150 turbine as the optimal choice from the available catalogue.

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Assessment of the usage of land resources

This section underscores the critical role of land usage in the successful implementation and operation of the Power-to-X plant. Given the significant spatial demands of the plant, understanding available land resources and potential limitations is essential. Land not only determines the practicality of establishing a Power-to-X plant but also impacts its design and functionality. This analysis centers on Bornholm's land resources, assessing how they could influence the plant's feasibility and overall design. The results from the stochastic assessment of land resources are presented in Table 10.

Table 10: Breakdown of land usage of the large Power-to-X plant by unit for various scenarios (H2 and NH3)

	H2-AEC	**H2-SOEC**	**H2-MIX**	**NH3-AEC***	**NH3-SOEC***	**NH3-MIX***
Electrolyser park facility [Ha]	6.9	5.3	6.4	7.8	5.7	7.3
Electrolyser air cooling [Ha]	3.4	1.4	2.9	3.9	1.5	3.3
NH3 prod. plant (+ASU) [Ha]	0.0	0.0	0.0	1.0	1.0	1.0
NH3 storage tanks (excl. safety distance) [Ha]	0.0	0.0	0.0	1.0	1.0	1.0
Space for plant construction and maintenance [Ha] **	20.6	13.3	18.7	27.5	18.5	25.2
Batteries [Ha]	0.0	0.0	0.0	0.7	1.0	0.9
Hydrogen storage (buried pipes) [Ha]	0.0	0.0	0.0	45.9	43.8	45.2
TOTAL land use without safety distance [Ha]	30.9	20.0	28.1	87.8	72.5	83.9
TOTAL land use without counting for buried pipes [Ha]	30.9	20.0	28.1	41.9	28.7	38.7

* The ammonia production plant requires a 1 km safety distance around the plant, resulting in a substantial increase in actual land usage.

** The space for plant construction (x2 actual space of plant) and the safety distance around it, were both obtained from discussions with the experts collaborating on the project.

Fig. 9 below offers a more visual representation of the land use of different units within the PtX plant under the studied scenarios in the stochastic analysis. The graph uses the data displayed in Table 10. It presents the data in a stacked bar plot with the land use of each of the units in hectares (Ha), indicating the amount of land required for the successful implementation and operation of the Power-to-X (PtX) plant. The height of each stacked segment corresponds to the total land use for the respective scenario.

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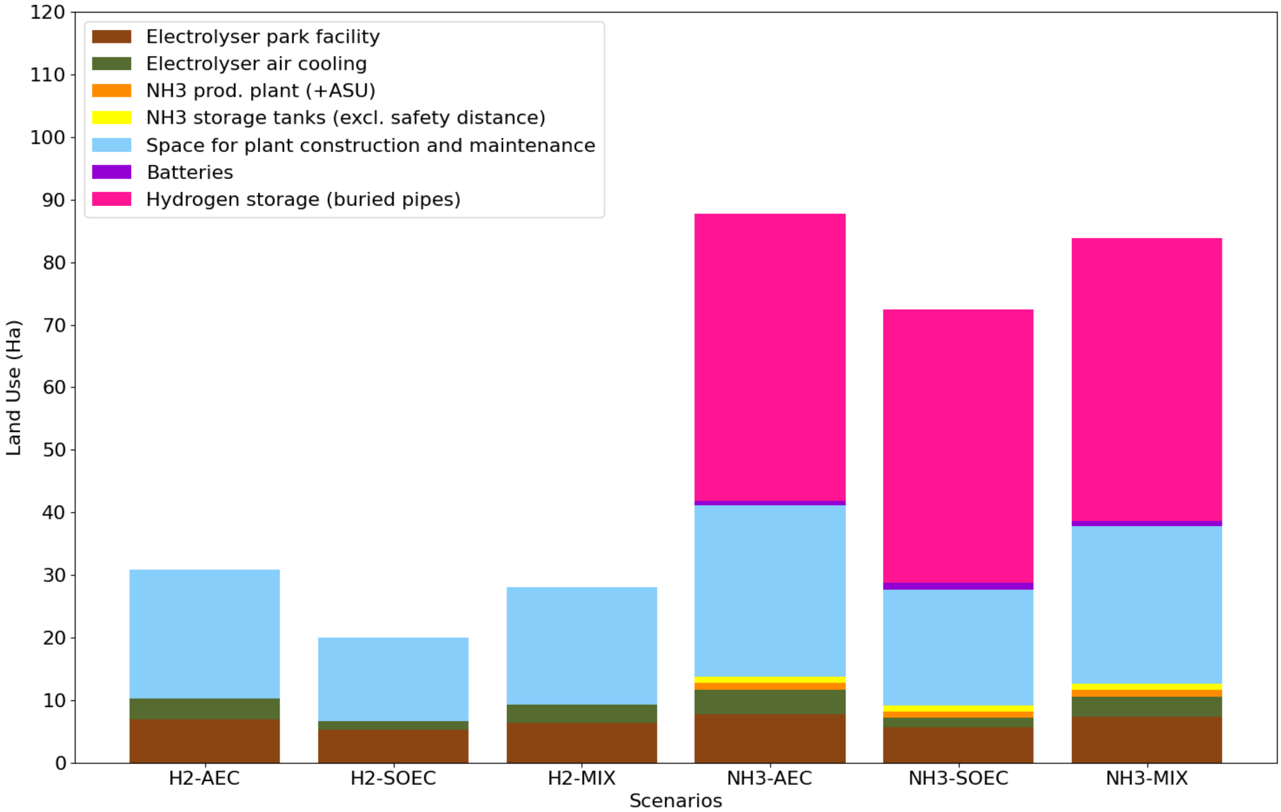

Figure 9: Breakdown of the total land use of the different PtX plant units. The areas correspond to the space occupied by the optimal unit capacities sized using the model's stochastic approach.

Conclusions

The stochastic analysis, incorporating weather data from 2016 to 2021, offers a more sophisticated understanding of optimal Power-to-X plant sizing. By considering a broad spectrum of weather scenarios, this method provides a more reliable estimate for plant sizing as it considers weather uncertainties, which have a significant effect on the size of the different plant units. The main takeaways from this analysis are:

- **PtX plant sizing under weather uncertainties:** Compared to the deterministic scenarios, the stochastic approach results in sizing of the production plants similar to the best-case year, where the capacity installed for most units is 5-10% smaller than in the deterministic typical year. Conversely, the storage units are sized larger than in the deterministic scenarios to ensure a flexible system facing uncertainties. The best-case year storage units are less than half the size of the storage units suggested by the stochastic analysis. The absence of specific cost metrics in the analysis is attributed to the stochastic model's inherent design, factoring in penalties for overproduction and underproduction. These findings underscore the complementary roles of deterministic and stochastic analyses in assessing energy system feasibility. Additionally, the complexity of the plant's operation highlights the potential necessity of employing alternative or supplementary modeling techniques for more nuanced insights into plant operation and cost structures.

- **Land usage assessment:** The examination of land resource availability emerges as a pivotal factor in the feasibility and design of the Power-to-X plant. Remarkably, the land required for hydrogen production is substantially lower than that for ammonia production. The demand for storage units (especially buried pipes) increases the land footprint even though the construction of other facilities on top of this hydrogen storage could reduce the ammonia plant size. Finally, approximately a 1km-radius safety distance around the ammonia plant should also be accounted for on top of the displayed land use.

4.2 Small-scale PtX plant supplementary study: methanol and biofuel production

This investigation was designed to complement the large-scale study, focusing specifically on the feasibility and implications of small-scale methanol and upgraded pyrolysis bio-oil production in Bornholm. Recognizing the potential constraints and unique opportunities of the island, this supplementary study analyzed different scenarios and configurations to assess the optimal production pathway, cost efficiency, and potential market integration for methanol and upgraded pyrolysis biofuel. While the small-scale plant study may not exhibit the same production capacity as its large-scale counterpart, it represents an essential investigation that broadens the understanding of Bornholm's renewable energy potential. The outcomes of this supplementary study not only complement the findings of the large-scale study but also provide a broader perspective on the array of possibilities for Bornholm's energy future.

As previously mentioned, a total of 8 scenarios were simulated for this analysis, representing a combination of one weather year, two electrolyzer types, two produced types of fuel, and two types of CO2 availability limits.

This investigation uniquely considered the weather data of the year 2018, providing a specific representation of weather conditions and their impact on the small-scale PtX plant. This approach allowed for a detailed understanding of the production cost and system performance under realistic circumstances, avoiding the artificial construct of an average year. In terms of CO2 availability, the scenarios differentiate between locally sourced CO2 (L) and a combination of locally sourced and imported CO2 (L+I). Finally, it is essential to emphasize again that all techno-economic input data utilized through all the analysis corresponds to predictions made for the year 2030.

The results for the optimal plant sizing and the cost analysis for the studied scenarios are presented in the following pages.

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Optimal Power-to-X plant sizing and cost analysis for a specific weather year (2018)

The optimal sizing of the different Power-to-X plant units for the 8 studied scenarios in this investigation is provided in Table 11.

Table 11: Optimal sizing of the small Power-to-X plant units for different scenarios under the additional analysis (MeOH and BioF)

	Methanol-AEC	Methanol-SOEC	Biofuel-AEC	Biofuel-SOEC
Wind Farm (WF) [1] **[MW]**				
Local CO2	26.1	22.7	2.9	2.8
Local + imports CO2	239.7	208.8	27.6	26.7
Solar Farm (SF) [2] **[MW]**				
Local CO2	49.2	43.6	6.2	5.7
Local + imports CO2	456.7	386.6	57.4	57.4
Electrolysis plant [MW]				
Local CO2	24.9	21.6	1.5	1.3
Local + imports CO2	219.1	185.8	13.0	13.0
Wastewater treat. plant [m3 H2O/h]				
Local CO2	5.4	5.4	0.4	0.4
Local + imports CO2	51.2	50.2	3.8	3.7
Methanol plant [t/h]				
Local CO2	2.0	2.0	*	*
Local + imports CO2	19.8	20.2	*	*
Biomass pyrolysis plant [t/h]				
Local CO2	*	*	1.6	1.6
Local + imports CO2	*	*	15.0	15.0
Bio-oil upgrading plant [t/h]				
Local CO2	*	*	1.0	1.0
Local + imports CO2	*	*	9.7	9.7
Batteries [MWh]				
Local CO2	80.0	67.0	9.7	9.4
Local + imports CO2	782.0	659.4	91.9	38.4
H2 storage (buried pipes) [t]				
Local CO2	7.4	6.9	1.8	1.7
Local + imports CO2	38.1	23.6	17.1	17.1

[1] The model selected the SP379-HH150 and SP450-HH100 turbines as the optimal choice for the biofuel and methanol production, respectively.
[2] The model selected the solar panels with 1-axis tracking as the optimal choice from the available photovoltaic technologies.

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In this specific small-scale analysis, our evaluation of the system and fuel production costs falls under two distinct approaches:

• Standard cost analysis: This primarily examines the total system costs and the fuel production costs for each of the studied scenarios without considering the revenues from co-products.

• Cost analysis with co-products selling revenue: In this approach, the selling of co-products from methanol and upgraded pyrolysis biofuel production are taken into account, providing a revised economic evaluation. In the context of methanol production, the monetized co-products consist of heat and oxygen. On the other hand, the upgraded pyrolysis bio-oil production yields co-products such as heat, oxygen, and biochar. These adjusted costs offer a comprehensive understanding of the system's economic viability when considering potential revenue from co-products.

These two cost investigations make more sense in the small-case PtX plant study compared to the large-scale PtX plant investigation as the uncertainties on the market prices, demand dynamics, and product allocation are smaller due to the lower volume of produced co-products.

For the **standard cost analysis**, Fig.10 visually represents the economic indicators for the various scenarios in 2018. Each scenario is depicted by a stacked bar indicating the total annualized cost per energy unit in €/MWh, detailing the cost of the individual plant units on the primary y-axis. The corresponding fuel production costs are showcased by black dots in €/MWh and €/kg. In this case, the fuel production costs are equal to the total annualized system cost per energy unit.

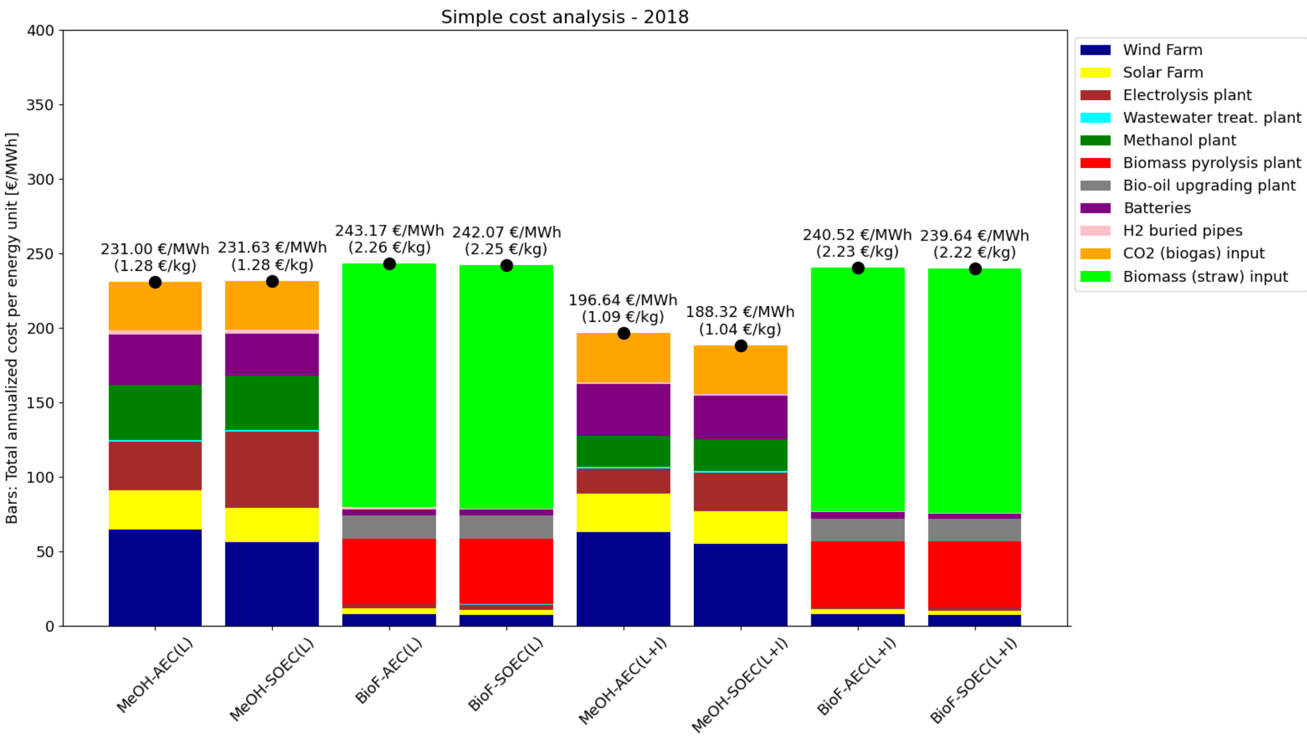

Figure 10: Comparative cost analysis for the scenarios for the year 2018. Standard cost analysis (supplementary study).

To supplement the graphical representation, Table 12 offers a numerical breakdown of the total system cost, and Table 13 provides a detailed summary of the fuel production cost for all scenarios within the small PtX plant study. Both tables include the costs corresponding to the standard cost analysis.

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Table 12: Breakdown of the total system cost of the small Power-to-X plant by unit for different scenarios under 2018 weather data (MeOH and BioF) - all costs are in [M€]-. Standard cost analysis.

	Methanol-AEC	Methanol-SOEC	Biofuel-AEC	Biofuel-SOEC
Wind Farm (WF)				
Local CO2	4.74	4.10	0.58	0.55
Local + imports CO2	43.43	37.82	5.45	5.01
Solar Farm (SF)				
Local CO2	1.93	1.71	0.30	0.22
Local + imports CO2	17.87	15.12	2.25	2.12
Electrolysis plant				
Local CO2	2.39	3.73	0.17	0.27
Local + imports CO2	11.70	18.18	0.86	1.34
Wastewater treat.				
Local CO2	0.08	0.08	0.01	0.01
Local + imports CO2	0.77	0.75	0.06	0.06
Methanol plant				
Local CO2	2.70	2.69	*	*
Local + imports CO2	14.20	14.50	*	*
Biomass pyrolysis				
Local CO2	*	*	3.23	3.23
Local + imports CO2	*	*	30.72	30.72
Bio-oil upgrading				
Local CO2	*	*	1.14	1.14
Local + imports CO2	*	*	10.81	10.83
Batteries				
Local CO2	2.47	2.06	0.30	0.28
Local + imports CO2	24.11	20.33	2.83	2.29
H2 storage (buried pipes)				
Local CO2	0.19	0.18	0.10	0.04
Local + imports CO2	1.00	0.62	0.44	0.45
CO2 (biogas)				
Local CO2	2.42	2.42	*	*
Local + imports CO2	22.81	22.81	*	*
Biomass (straw)				
Local CO2	*	*	12.00	12.00
Local + imports CO2	*	*	113.96	113.96
TOTAL				
Local CO2	16.93	16.97	17.82	17.74
Local + imports CO2	135.89	130.13	167.38	166.76

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Table 13: Fuel production cost of different scenarios for the supplementary investigation (MeOH and BioF). Standard cost analysis.

	Methanol-AEC	Methanol-SOEC	Biofuel-AEC	Biofuel-SOEC
Fuel production cost [€/MWh]/[€/kg]				
Local CO2	231.00/1.28	231.63/1.28	243.17/2.26	242.07/2.25
Local + imports CO2	196.64/1.09	188.32/1.04	240.52/2.23	239.64/2.22

For the **cost analysis with co-products selling revenue**, Fig.11 visually represents the economic indicators for the various scenarios in 2018. Each scenario is depicted by a stacked bar indicating the total annualized cost per energy unit in €/MWh, detailing the cost of the individual plant units on the primary y-axis. The corresponding fuel production costs are showcased by black dots in €/MWh and €/kg. In this case, the fuel production costs are equal to the sum of all the values (positive and negative) for all the costs and revenues plotted in the bars.

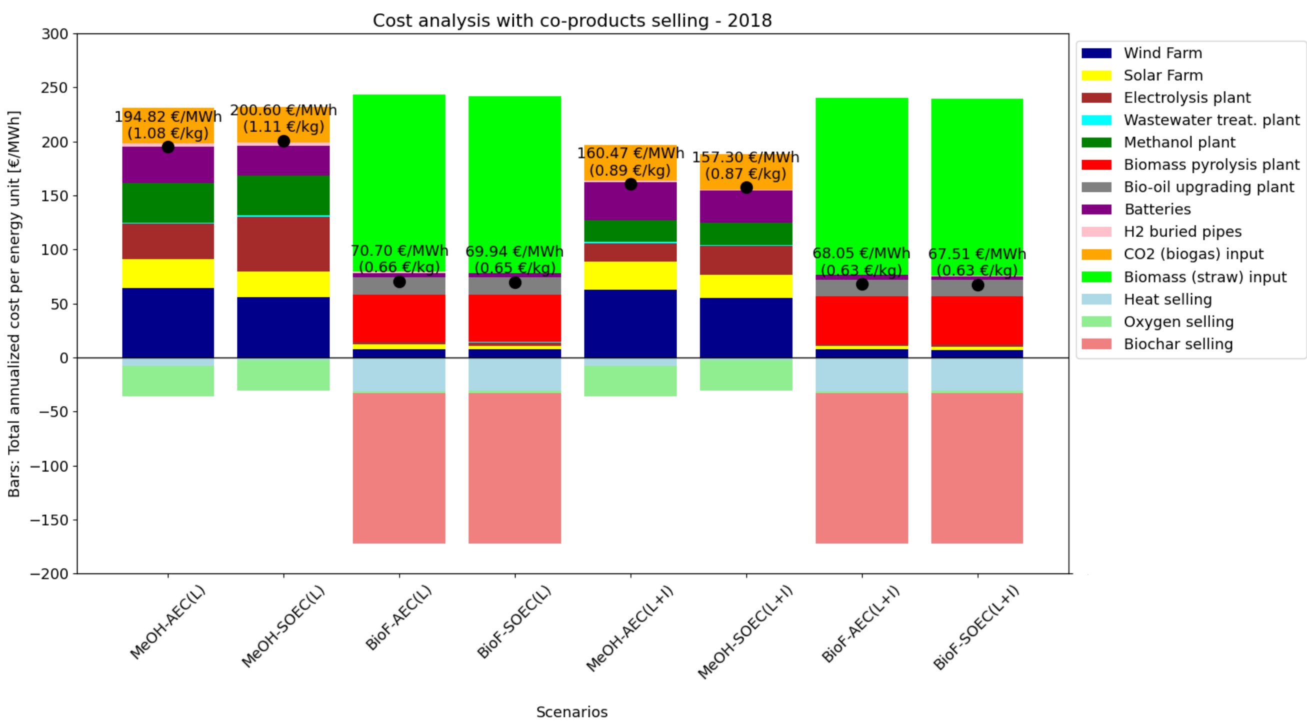

Figure 11: Comparative cost analysis for the scenarios for the year 2018. Cost analysis considering the revenue from selling co-products (supplementary study).

To supplement the graphical representation, Table 14 offers a numerical breakdown of the total system cost (the costs of the different units are the same as the ones found in Table 13. The revenues from co-product selling are displayed). Table 15 provides the fuel production cost for all scenarios within the small PtX plant study taking into account the selling of the co-products.

Selling and buying prices for co-products and raw materials (biomass) were sourced from literature or provided by the project partner SkyClean. Specifically, the prices were set at 0.02€/kWh of Heat, 0.26€/kg of biochar, 0.1€/kg of O2, and 0.11€/kg of biomass [37], [38], [39]. These numbers take many assumptions into account and should be used as an indicative value. The results from this analysis try to qualitatively assess the potential reduction of the fuel cost when co-products are sold.

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Table 14: Breakdown of the total system cost of the small Power-to-X plant by unit for different scenarios under 2018 weather data (MeOH and BioF) - all costs are in [M€]-. Cost analysis with co-products selling. The costs of the different units is the same as the ones displayed in Table 13

	Methanol-AEC	**Methanol-SOEC**	**Biofuel-AEC**	**Biofuel-SOEC**
...				
Heat selling				
Local CO2	-0.56	-0.18	-2.30	-2.27
Local + imports CO2	-5.26	-1.70	-21.79	-21.56
Oxygen selling				
Local CO2	-2.09	-2.09	-0.14	-0.14
Local + imports CO2	-19.74	-19.73	-1.31	-1.31
Biochar selling				
Local CO2	*	*	-10.21	-10.21
Local + imports CO2	*	*	-96.92	-96.92
'New' TOTAL				
Local CO2	14.28	14.70	5.17	5.12
Local + imports CO2	110.89	108.70	47.36	46.97

Table 15: Fuel production cost of different scenarios for the supplementary investigation (MeOH and BioF). Cost analysis with co-products selling.

	Methanol-AEC	**Methanol-SOEC**	**Biofuel-AEC**	**Biofuel-SOEC**
Fuel production cost [€/MWh]/[€/kg]				
Local CO2	194.82/1.08	200.60/1.11	70.70/0.66	69.94/0.65
Local + imports CO2	160.47/0.89	157.30/0.87	68.05/0.63	67.51/0.63

Conclusions

- **Fuel production costs:** The investigation shows that, under the standard cost analysis, there are small differences in the production costs of methanol and upgraded pyrolysis bio-oil in terms of €/MWh, being methanol slightly cheaper to produce. However, when considering the sale of co-products the difference between the production costs of these fuels could become significant, being the upgraded pyrolysis biofuel way cheaper due to the high revenue coming from the biochar sale.

- **Electrolyzer technology impact:** In contrast to the large-scale PtX plant study, the electrolyzer technology does not significantly influence the total cost of the system in this small-scale scenario. This may be attributed to the reduced size of the electrolyzer, which diminishes the cost impact of technology selection.

- **Economies of scale:** The study reveals that the effects of economies of scale are not pronounced for the production of upgraded pyrolysis oil, whereas it is found that the methanol LCOF experiences a 15-19% drop in price across the electrolyzer technologies when increasing the size of the plant nine-fold. Consequently, it is interesting to consider large-scale facilities for the methanol pathway to reduce its costs.

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- **Cost and revenue contributions in different scenarios:** For the methanol (L+I) scenario, major contributions to the total system cost come from the wind farm, the batteries, and the CO2 (biogas) inputs. Conversely, in all the upgraded pyrolysis biofuel scenarios the biomass (straw) input accounts for over half of the costs, followed by the pyrolysis plant. This insight informs potential cost optimization strategies. In terms of total revenues, oxygen sales are the primary source of income for the methanol scenario, whereas the sale of biochar stands out as the most significant contributor in the case of upgraded pyrolysis bio-oil.

- **Co-products selling opportunity and considerations:** As it can be seen in the graphs above, the sale of co-products could reduce the production cost of fuel drastically (for instance, upgraded pyrolysis biofuel production costs are reduced by around three times). However, the revenues coming from the sale of these co-products rely on strong assumptions that carry uncertainties related to the market prices, demand dynamics, or other considerations that may affect the final cost analysis.

5 Final note

Work Package 2 (WP2), focusing on the modeling of scenarios for the Power-to-X plant, has led to a series of comprehensive investigations and analyses that provide insights into current possibilities and a roadmap to future innovation and sustainability, uniquely tailored to the context of Bornholm and beyond.

Task 1 consisted of the development of an optimization model, known as the OptiPlant model, to model Power-to-X fuel production systems with a high variety of customizable input parameters and to optimize them according to different criteria. Task 2 focused on modeling and analyzing a variety of potential Power-to-X scenarios in Bornholm. Both tasks were successfully accomplished.

It is the intention of the DTU Management research team to further investigate the outcomes and insights gained from these tasks and to craft a scientific paper based on the main contents and topics of this report. This effort aims to serve as a meaningful contribution to the global scientific dialogue on renewable energy systems modeling.

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6 Appendix: Techno-economical input data for the different PtX plant units

This appendix contains the essential techno-economic input data used to model the different units of the Power-to-X (PtX) plants studied in our investigations. The data provided in this section span across a variety of parameters, including costs, efficiencies, lifetimes, and more for different plant components, thus providing a comprehensive foundation for our modeling efforts. These tables serve as valuable references, supplying the detailed technical and financial metrics that underpin our scenario evaluations. It is the compilation of this information that has allowed for a nuanced understanding of the feasibility and implications of the proposed PtX plant designs. The references/sources of each of the values are also included in the footer of the tables.

6.1 Power Supply

The power supply covered in WP2 will focus solely on offshore wind technology. The four different designs of offshore wind turbines investigated vary from one another by their power rating, hub height, and rotor diameter as can be seen from WP1. These parameters will serve as input for the power source directly linked to the Power-to-X plant within the model. The investment and operational costs associated with each technology are detailed in Table 2. In order to obtain the most representative production profiles, six different years were investigated for offshore wind, from 2016 to 2021. The most relevant years will be considered for the model in order to have a lower, upper, and average estimate of power profiles.

6.1.1 Offshore Wind

Table 16: Offshore wind turbines

Turbine	Site	Power rating [kW]	Hub height [m]	Rotor diameter [m]	Manufacturer	Turbine
SP379-HH100	Offshore	8000	100	164	Vestas	V164/8000
SP379-HH150	Offshore	8000	150	164	Vestas	V164/8000
SP450-HH100	Offshore	9500	100	164	Vestas	V164/9500
SP450-HH150	Offshore	9500	150	164	Vestas	V164/9500

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Table 17: Offshore wind including connection to the inland electrolyzer

Parameter	Turbine	Worst	Bench	Best	2030	2040	2050
CAPEX [€2019/kW]	Off SP379-HH100	2205.190	2205.190	2205.190	1998.130	1873.894	1842.835
	Off SP379-HH150	2534.607	2534.607	2534.607	2296.616	2153.821	2118.122
	Off SP450-HH100	1988.123	1988.123	1988.123	1801.445	1689.438	1661.437
	Off SP450-HH150	2265.527	2265.527	2265.527	2052.801	1925.166	1893.257
Fixed cost [€2019/kW/y]	Off SP379-HH100	41.773	41.773	41.773	37.596	34.588	33.836
	Off SP379-HH150	41.773	41.773	41.773	37.596	34.588	33.836
	Off SP450-HH100	41.773	41.773	41.773	37.596	34.588	33.836
	Off SP450-HH150	41.773	41.773	41.773	37.596	34.588	33.836
Var cost [€2019/kWh]	Off SP379-HH100	0.003	0.003	0.003	0.003	0.003	0.003
	Off SP379-HH150	0.003	0.003	0.003	0.003	0.003	0.003
	Off SP450-HH100	0.003	0.003	0.003	0.003	0.003	0.003
	Off SP450-HH150	0.003	0.003	0.003	0.003	0.003	0.003
Lifetime [years]	Off SP379-HH100	27	27	27	30	30	30
	Off SP379-HH150	27	27	27	30	30	30
	Off SP450-HH100	27	27	27	30	30	30
	Off SP450-HH150	27	27	27	30	30	30
Annuity factor	Off SP379-HH100	0.091	0.091	0.091	0.089	0.089	0.089
	Off SP379-HH150	0.091	0.091	0.091	0.089	0.089	0.089
	Off SP450-HH100	0.091	0.091	0.091	0.089	0.089	0.089
	Off SP450-HH150	0.091	0.091	0.091	0.089	0.089	0.089
CO2 emission infrastructure [kg_{CO2e}/kW/year]	Off SP379-HH100	53.53	53.53	53.53	36.579	19.628	2.677
	Off SP379-HH150	53.53	53.53	53.53	36.579	19.628	2.677
	Off SP450-HH100	53.53	53.53	53.53	36.579	19.628	2.677
	Off SP450-HH150	53.53	53.53	53.53	36.579	19.628	2.677
Land use [m^2/kWe]	Off SP379-HH100	203.96	177.36	150.76	171.96	169.84	171.26
	Off SP379-HH150	203.96	177.36	150.76	171.96	169.84	171.26
	Off SP450-HH100	203.96	177.36	150.76	171.96	169.84	171.26
	Off SP450-HH150	203.96	177.36	150.76	171.96	169.84	171.26
Capacity factors at Bornholm using Corres [%]	Off SP379-HH100	44.70%	44.70%	44.70%	44.70%	44.70%	44.70%
	Off SP379-HH150	49.70%	49.70%	49.70%	49.70%	49.70%	49.70%
	Off SP450-HH100	41.50%	41.50%	41.50%	41.50%	41.50%	41.50%
	Off SP450-HH150	46.60%	46.60%	46.60%	46.60%	46.60%	46.60%
LCOE [€2019/MWh]	Off SP379-HH100	57.7	57.7	57.7	57.7	57.7	57.7
	Off SP379-HH150	58.6	58.6	58.6	58.6	58.6	58.6
	Off SP450-HH100	57.1	57.1	57.1	57.1	57.1	57.1
	Off SP450-HH150	56.7	56.7	56.7	56.7	56.7	56.7

6.2 Power-to-X plant

6.2.1 Electrolyzer

Production of green hydrogen is produced via water electrolysis powered by fully renewable energy sources. Alkaline Electrolysis Cell (AEC), Solid Oxide Electrolysis Cell (SOEC), and the combined use of both AEC and SOEC technologies are considered in the model. Each of these technologies has upsides and downsides from a techno-economic standpoint. AEC has been commonly used in the past for green hydrogen production having a significantly lower capital cost compared with other similar technologies such as SOEC or Proton Exchange Membrane (PEM). On the other hand, SOEC is characterized to perform with higher efficiency due to its high operating temperature, therefore decreasing the operational electricity required. For its functionality, this technology requires both power and heat. The integration of external waste heat is considered in the model for the scenarios using fully or partially the SOEC electrolyser. Additionally, the efficiency of the electrolyzers is found to depend on the load, see more in the load curve in Figure 12. The represenation of the load has been included in the model with a piece-wise linearization approach. However, after conducting the analysis, it was observed that the variation in efficiency with load had minimal effect on the overall results. Consequently, for simplicity and practicality, it was decided to treat the efficiency as approximately constant for the different scenarios, yielding consistent results without compromising the accuracy of the model.

Table 18: Electrolyser Park including utilities and piping

Parameter	Units	AEC 2025	AEC 2030	AEC 2050	SOEC (heat integration) 2025	SOEC (heat integration) 2030	SOEC (heat integration) 2050	SOEC (no heat integration) 2025	SOEC (no heat integration) 2030	SOEC (no heat integration) 2050
Minimal load	% of capacity	-	-	-	-	2[1]	-	-	2[2]	-
Ramping constraint up	% of capacity / h	-	-	-	-	7[3]	-	-	7[3]	-
Ramping constraint down	% of capacity / h	-	-	-	-	7[3]	-	-	7[3]	-
Recovered low temp heat[4]	kWh_{th}/kg_{H_2}	-	-	-	-	0	-	-	0	-
Recovered high temp heat[4]	kWh_{th}/kg_{H_2}	-	-	-	-	0	-	-	0	-
Total electrical consumption	kWh / kg_{H_2}	50	49.8	49	-	38	38	44	43.2	40
H2 production rate [5]	$kg_{H_2}/kg_{H_2Odemin}$	0.111	0.111	0.1111	0.111	0.111	0.111	0.111	0.111	0.111
Investment expenditure	€/ (kg_{H_2}/h)	55000	39840	24900	114000	95000	26600	129600	100000	28000
Fixed cost	€ / (kg_{H_2}/h)/year	5500	3984	2490	4560	3800	1064	5184	4000	1120
Variable cost[6]	€/kg_{H_2}	-	-	-	-	-	-	-	-	-
Life Time	years	30	30	30	30	30	30	30	30	30
Annuity factor[7]	-	0.088	0.088	0.088	0.088	0.088	0.088	0.088	0.088	0.088

[1] Between 1-3 % capacity. Assuming a large-scale plant of 250MW. For smaller plants, the minimal load could be 3-4MW.
[2] Between 1-3 % capacity. One section (3-4MW) with 80-100%, sections go in and out of hot standby with 5% energy as steam.
[3] Usually between 5-10%.
[4] After heat integration with fuel plant, if any. Excess heat for district heating.
[5] From demineralized water.
[6] Excluding electricity expenses.
[7] To annualize investments. Assuming discount rate 7% and 5% interest rate.

6.2.2 Load curve AEC

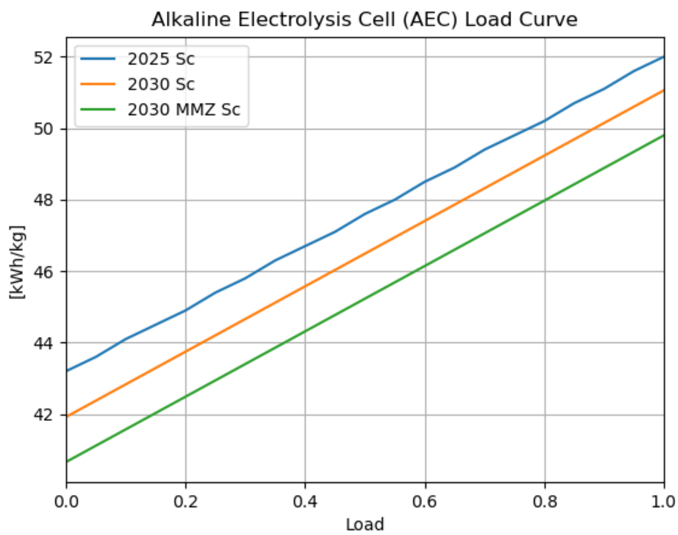

Figure 12: AEC curve

Table 19: Linear regression parameters of the curves in Figure12

	2025 Sc	2030 Sc	2030 MMZ Sc
Slope	8.824	9.141	9.141
Origin	43.176	41.919	40.659

6.2.3 Ammonia plant

Green ammonia production relies on ammonia synthesis plants that employ the Haber-Bosch (HB) process, which involves combining nitrogen and hydrogen. The nitrogen is sourced from a cryogenic air separation (ASU) unit, while the hydrogen is generated through electrolysis, utilizing either AEC, SOEC, or a combination of both methods. The ammonia synthesis plant has been modeled to operate at a minimal load, typically ranging from 10% to 40% of its full capacity. Regardless of whether AEC

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or SOEC is used, the ammonia production rate is assumed to be 5.56 kg of ammonia per kilogram of hydrogen, with an approximate electrical consumption of 0.59 kWh per kilogram of ammonia.

Table 20: Standard e-Ammonia plant and ASU

Parameter	Units	AEC 2025	AEC 2030	AEC 2050	SOEC 2025	SOEC 2030	SOEC 2050	25% SOEC, 75% AEC 2025	25% SOEC, 75% AEC 2030	25% SOEC, 75% AEC 2050
Maximum installed capacity	kg_{NH_3}/h	9583	95833	191667	9583	95833	191667	9583	95833	191667
Minimal load	% of capacity	-	20[1]	-	-	20[1]	-	-	20[1]	-
Ramping constraint up	% of capacity/min	-	3[2]	-	-	3[2]	-	-	3[2]	-
Ramping constraint down	% of capacity/min	-	3[2]	-	-	3[2]	-	-	3[2]	-
Recovered low temp heat[3]	kWh_{th}/kg_{NH_3}	-	-	-	0	0	0	0	0	0
Recovered high temp heat[3]	kWh_{th}/kg_{NH_3}	-	-	-	0	0	0	0	0	0
Production rate[4]	kg_{NH_3}/kg_{H_2}	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56
Electrical consumption	kWh/kg_{NH_3}	0.47	0.45	0.45	0.61	0.59	0.59	0.61	0.59	0.59
Investment expenditure	€/(kg_{NH_3}/h)	18058	6662	5084	18058	6662	5084	18058	6662	5084
Fixed cost	€/($kg_{NH_3}/h/year$)	722.3	266.5	203.4	722.3	266.5	203.4	722.3	266.5	203.4
Variable cost[5]	€/kg_{NH_3}	0	0	0	0	0	0	0	0	0
Life Time	years	30	30	30	30	30	30	30	30	30
Annuity factor[6]	-	0.088	0.088	0.088	0.088	0.088	0.088	0.088	0.088	0.088
CO2 emissions during process	$kg_{CO2e}/(kg_{NH_3}/h/year)$	0	0	0	0	0	0	0	0	0

[1] Between 10-40%.
[2] Between 1-10% of capacity/min.
[3] After heat integration, if any. Excess heat for district heating.
[4] Process mass efficiency, 99% converted.
[5] Excluding electricity expenses.
[6] To annualize investements.

6.2.4 Water supply

Table 21: Water supply: the unit that provides purified water that can be directly used in the electrolyzer (alkaline electrolyzer)

Parameter	Units	2025 LB[1]	2025 B[2]	2025 HB[3]	2030 LB[1]	2030 B[2]	2030 HB[3]	2050 LB[1]	2050 B[2]	2050 HB[3]
Water Supply type I: purified waste water treatment plant										
Minimum load[4]	% of capacity	0	0	0	0	0	0	0	0	0
Ramping constraint up	% of capacity/h	100	100	100	100	100	100	100	100	100
Ramping constraint down	% of capacity/h	100	100	100	100	100	100	100	100	100
Recovered low temp heat[5]	kWh_{th}/kg_{H_2}	0	0	0	0	0	0	0	0	0
Recovered high temp heat	kWh_{th}/kg_{H_2}	0	0	0	0	0	0	0	0	0
Electrical consumption [6]	$kWh/\ kg_{H_2O}$	0.001	0.0025	0.004	-	-	-	-	-	-
Investment expenditure	€/(kg_{H_2O}/h)	107.552	120.993	134.434	-	-	-	-	-	-
Fixed cost	€/(kg_{H_2O}/h)/year	3.227	3.630	4.0330	-	-	-	-	-	-
Variable cost[7]	€/kg_{H_2O}	0	0.000065	0.00013	-	-	-	-	-	-
Life Time	years	15	15	15	15	15	15	20	20	20
Discount rate	%	8%	8%	8%	8%	8%	8%	8%	8%	8%
Annuity factor [8]	-	0.117	0.117	0.117	0.117	0.117	0.117	0.102	0.102	0.102
Water Supply type II: sea water (Baltic sea)										
Minimum load[4]	% of capacity	0	0	0	0	0	0	0	0	0
Ramping constraint up	% of capacity/h	100	100	100	100	100	100	100	100	100
Ramping constraint down	% of capacity/h	100	100	100	100	100	100	100	100	100
Recovered low temp heat [5]	kWh_{th}/kg_{H_2}	0	0	0	0	0	0	0	0	0
Recovered high temp heat	kWh_{th}/kg_{H_2}	0	0	0	0	0	0	0	0	0
Electrical consumption	$kWh/\ kg_{H_2O}$	0.0045	0.00675	0.009	-	-	-	-	-	-
Investment expenditure	€/(kg_{H_2O}/h)	134.434	147.877	161.321	-	-	-	-	-	-
Fixed cost	€/(kg_{H_2O}/h)/year	4.033	4.436	4.840	-	-	-	-	-	-
Variable cost [7]	€/kg_{H_2O}	0	0	0	-	-	-	-	-	-
Life Time	years	15	15	15	15	15	15	20	20	20
Discount rate	%	8%	8%	8%	8%	8%	8%	8%	8%	8%
Annuity factor [8]	-	0.117	0.117	0.117	0.117	0.117	0.117	0.102	0.102	0.102
Water Supply type III: drinking water										
Minimum load[4]	% of capacity	0	0	0	0	0	0	0	0	0
Ramping constraint up	% of capacity/h	100	100	100	100	100	100	100	100	100
Ramping constraint down	% of capacity/h	100	100	100	100	100	100	100	100	100
Recovered low temp heat [5]	kWh_{th}/kg_{H_2}	0	0	0	0	0	0	0	0	0
Recovered high temp heat	kWh_{th}/kg_{H_2}	0	0	0	0	0	0	0	0	0
Electrical consumption	$kWh/\ kg_{H_2O}$	0.001	0.00275	0.0045	-	-	-	-	-	-
Investment expenditure	€/(kg_{H_2O}/h)	64.531	72.598	80.664	-	-	-	-	-	-
Fixed cost	€/(kg_{H_2O}/h)/year	1.936	2.178	2.420	-	-	-	-	-	-
Variable cost[7]	€/kg_{H_2O}	0.00013	0.0002	0.00027	-	-	-	-	-	-
Life Time	years	15	15	15	15	15	15	20	20	20
Discount rate	%	8%	8%	8%	8%	8%	8%	8%	8%	8%
Annuity factor [8]	-	0.117	0.117	0.117	0.117	0.117	0.117	0.102	0.102	0.102

[1] Lower boundary value.
[2] Benchmark value.
[3] Higher boundary value.
[4] It can be easily shut down on demand.
[5] Excess heat for district heating.
[6] Including consumption for additional infrastructure.
[7] Excluding electricity expenses.
[8] To annualize investments.

6.3 Storage solutions

6.3.1 Hydrogen intermediate storage including compression

The green hydrogen produced by the electrolysers can serve two main purposes: it can either be used directly for ammonia/methanol production, or it can be transported to neighboring countries through pipelines. These will be explored in greater detail in the following sections. Additionally, an intermediate hydrogen storage solution has been thoroughly studied and implemented as an input for the model. The study focuses on incorporating two storage technologies for hydrogen: 800-bar above-ground steel tanks and 100-bar underground hydrogen pipes. Depending on the chosen storage option, the electrical consumption required to increase the pressure from 20 to 800 bar will fall within the range of 3.5-4 kWh per kilogram of hydrogen. To ensure the gas remains at the appropriate pressure, the above-ground steel tanks have been designed with a minimum load requirement of 3% of their capacity, while the underground pipes solution necessitates a 9% capacity load. Regarding their lifespans, the storage tanks can be expected to last around 10 years, depending on the frequency of filling and emptying. In contrast, underground pipes offer a longer lifespan of 40-50 years.

Table 22: Above ground steel tanks (800 bars storage)

Parameter	Units	2025 LB	2025 B	2025 HB	2030 B	2050 B
Minimal load (cushion gas)	% of capacity	-	3%[1]	-	3%[1]	3%[1]
Ramping constraint up	% of capacity / h	-	100%	-	100%	100%
Ramping constraint down	% of capacity / h	-	100%	-	100%	100%
Recovered low temp heat[2]	kWh_{th}/kg_{H_2}	-	0	-	-	-
Recovered high temp heat[2]	kWh_{th}/kg_{H_2}	-	0	-	-	-
Electrical consumption	kWh/kg_{H_2}	-	3.5[3]		3.5[3]	3.5[3]
Investment expenditure[4]	$€/(kg_{H_2 \text{max stored}})$	-	900	1000	800	500[5]
Fixed cost	$€/(kg_{H_2 \text{max stored}})/year$	-	27[6]	30[6]	25[6]	15[6]
Variable cost [7]	$€/kg_{H_2}$	-	0	-	0	0
Life Time	years	10[8]	10[8]	-	10[8]	10[8]
Discount rate	%	8%	8%	-	8%	8%
Annuity factor[9]	-	0.149	0.149	-	0.149	0.149
Lifecycle CO2 emissions infrastructure	$kg_{CO2e}/(kg_{H_2 \text{max stored}})/year$	-	0.006	-	0.006	0.006
CO2 emissions during process	$(kg_{CO2e}/kg_{H_2})/year$	-	0	-	0	0

[1] The amount of gas needed to maintain adequate pressure.
[2] After heat integration, if any. Excess heat for district heating.
[3] Energy consumption to reach from 20 to 800 bar will be in ranges from 3.5 to 4 KWh/kg_{H_2}.
[4] Including compressor expenses.
[5] It is predicted that compressor and pressurized storage components cost will be half of today's cost.
[6] 3-4% of Capex.
[7] Excluding electricity expenses.
[8] Life span of high-pressure storage tanks will be 10 years, depending on how frequently the filling and emptying are taking place.
[9] To annualize investments.

Table 23: Underground hydrogen pipes (100 bars)

Parameter	Units	2025 B	2030 B	2050 B
Minimal load (cushion gas)	% of capacity	9%	9%	9%
Ramping constraint up	% of capacity / h	100%	100%	100%
Ramping constraint down	% of capacity / h	100%	100%	100%
Recovered low temp heat [1]	kWh_{th}/kg_{H_2}	0	0	0
Recovered high temp heat [1]	kWh_{th}/kg_{H_2}	0	0	0
Electrical consumption [2]	kWh/kg_{H_2}	0.94	0.94	0.94
Investment expenditure	$€/(kg_{H_2 \text{max stored}})$	500[3]	500[3]	250
Fixed cost	$€/(kg_{H_2 \text{max stored}})/year$	15[4]	15[4]	7[4]
Variable cost	$€/kg_{H_2}$	0	0	0
Life Time	years	50[5]	50[5]	50[5]
Discount rate	%	8%	8%	8%
Annuity factor[6]	-	0.082	0.082	0.082
Lifecycle CO2 emissions infrastructure	$kg_{CO2e}/(kg_{H_2 \text{max stored}})/year$	0.006	0.006	0.006
CO2 emissions during process	$(kg_{CO2e}/kg_{H_2})/year$	0	0	0
Land use	$m^2/(kg_{H_2 \text{max stored}})$	1.00	1.00	1.00

[1] After heat integration, if any. Excess heat for district heating.
[2] Including compression from 20 to 100 bars.
[3] Excluding compressor expenses. Below 250 bar working pressure our estimate will be about 250EUR/$kg_{H_2 \text{stored}}$.
[4] 3-4% of Capex.
[5] Hydrogen pipeline lifetime will be between 40-50 years.
[6] To annualize investments.

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6.3.2 Battery Park Storage

The model has considered battery park and storage solutions, opting for lithium-ion batteries for this study. These batteries demonstrate rapid ramping rates, both up and down, at approximately 100(DoD) of 90will reach 100kWh per every kWh stored. This is particularly applicable to large-scale systems, where overhead auxiliary power is more efficient, and the majority of losses stem from copper losses. The battery pack is designed to cater to energy-intensive load-shifting applications, with an expected lifespan of approximately 7 years. Alternatively, if the system undergoes power-intensive use with low throughput and only occasional full discharge, its estimated lifespan can extend up to 15-17 years. In terms of land usage, the investigation is conducted taking into consideration a 52 square meters container, considering spacing, and other equipment. Each container can store between 2-5MWh, typically around 3MWh. However, it is essential to note that this technology's development does not necessarily yield the most cost-effective solutions with the smallest footprint. The main reason for this is the relatively low demand for stationary applications.

Table 24: Li-Ion battery park

Parameter	Units	2025 LB	2025 B	2025 HB	2030 B	2050 B
Minimal load[1]	% of capacity	-	10%	-	0%	0%
Ramping constraint up	% of capacity / h	-	100%	-	100%	100%
Ramping constraint down	% of capacity / h	-	100%	-	100%	100%
Recovered low temp heat[2]	kWh_{th}/kWh_{stored}	-	0	-	0	0
Recovered high temp heat[2]	kWh_{th}/kWh_{stored}	-	0	-	0	0
Electrical consumption[3]	kWh / kWh_{stored}	-	0.12[4]	-	0.1[4]	0.05[4]
Investment expenditure	€/ ($kWh_{max\ stored}$)	300[5]	550[5]	750[5]	180[5]	145[5]
Fixed cost	€ / ($kWh_{max\ stored}$)/year	-	8.25[6]	-	2.7[6]	2.175[6]
Variable cost	€/kWh	-	0[7]	-	0[7]	0[7]
Life Time	years	7[8]	15[8]	17[8]	20[8]	30[8]
Discount rate	%	8%	8%	8%	8%	8%
Annuity factor[9]	-	0.192	0.117	0.110	0.102	0.089
Lifecycle CO2 emissions infrastructure	kg_{CO2e}/($kWh_{max\ stored}$)/year	-	1.573	-	1.573	1.573
CO2 emissions during process	(kg_{CO2e}/kWh)/year	-	0	-	0	0
Land use	m^2/($kWh_{max\ stored}$)	0.0260[10]	0.0173[10]	0.0104[10]	0.0173[10]	0.0173[10]

[1] Maximum discharge level. It is easily accessible 90% DOD technology without increased cost.
This has improved rapidly and we expect it to be 100% DOD in 2030 for Li-Ion.
[2] After heat integration, if any. Excess heat for district heating.
[3] Round trip efficiency losses.
[4] Valid for large-scale systems where overhead auxiliary power is more efficient. Losses are converging towards only copper losses.
[5] High costs are if logistics and groundwork are difficult in the area. Low cost if lithium price is reduced.
[6] 1-2% of capex per year.
[7]No variable cost to the knowlegde. If cycling counts as a cost then would be driven by throughput. This is excluding electricity expenses.
[8]Previous figures were very high. Assuming energy intensive use for load shifting you would have about 7 years of life.
Power-intensive use with low throughput and only some full discharges lifetime could be 15-17 years.
[9] To annualize investments.
[10] Based on 40 ft containers (26m^2) using 52m^2 per container to include spacing and other equipment.
In a container, its fit at least 2MWh, normally 3MWh, and maximum 5MWh.
The development would drive cost-effective solutions with the smallest footprint due to no demand for stationary applications.

6.4 Techno-economical input data for 2040 and 2050

Table 25: Input Economical Assumptions for 2040

Type of units	Capacity	Investment	Fixed cost	Variable cost
Units	-	€/Capacity installed	€/Capacity installed/y	€/Output
NH_3 plant + ASU - AEC	kg_{NH_3}/h	5873.2	234.9[1]	0.0001
NH_3 plant + ASU - SOEC	kg_{NH_3}/h	5873.2	234.9[1]	0.0001
Desalination plant	kg_{H_2O}/h	134.4	4[2]	0.0003
Waste water plant	kg_{H_2O}/h	107.6	3.2[2]	0
Electrolyser Park AEC	kg_{H_2}/h	32370	3237[3]	0
Electrolyser Park SOEC heat integrated	kg_{H_2}/h	27392	2342[4]	0
Electrolyser Park SOEC alone	kg_{H_2}/h	27392	2342[4]	0
Electrolyser Park 75AEC-25SOEC$_{HI}$	kg_{H_2}/h	31125.5	3013.3	0
Electrolyser Park 75AEC-25SOEC$_{A}$	kg_{H_2}/h	31125.5	3013.3	0
H_2 storage tank	kg_{H_2}	650	19.5[5]	0
H_2 storage buried pipes	kg_{H_2}	250[6]	7.5[5]	0
OFF_SP379-HH100	kW	1873.9[7]	34.6[7]	0.0026[7]
OFF_SP379-HH150	kW	2153.8[7]	34.6[7]	0.0026[7]
OFF_SP450-HH100	kW	1689.4[7]	34.6[7]	0.0026[7]
OFF_SP450-HH150	kW	1925.2[7]	34.6[7]	0.0026[7]
Battery Park	kWh	164	2.5	0

[1] 4% Capex based on [4].
[2] 3% Capex based on [7].
[3] Using 10% Capex based on [4].
[4] 8.55% Capex based on [18].
[5] 3% Capex based on [16].
[6] Based on [16] for a working pressure around 100 bars.
[7] From [21].

Table 26: Input Technological Assumptions for 2040

Type of units	Input/Output	Capacity	Fuel production rate	Load min	Electrical consumption
Units	-	-	kg output/kg input	% of max capacity	kWh/output
NH_3 plant + ASU - AEC	H_2/NH_3	kg_{NH_3}/h	5.6[1]	10[1]	0.4[1]
NH_3 plant + ASU - SOEC	H_2/NH_3	kg_{NH_3}/h	5.6[1]	10[1]	0.6[1]
Desalination plant	$-/H_2O$	kg_{H_2O}/h	0	0	0.004[2]
Waste water plant	$-/H_2O$	kg_{H_2O}/h	0	0	0.004[2]
Electrolyser Park AEC	H_2O/H_2	kg_{H_2}/h	0.1[3]	0	49.4[1]
Electrolyser Park SOEC heat integrated	H_2O/H_2	kg_{H_2}/h	0.1[3]	0	37.9[4]
Electrolyser Park SOEC alone	H_2O/H_2	kg_{H_2}/h	0.1[3]	0	41.6[1]
Electrolyser Park 75AEC-25SOEC$_{HI}$	H_2O/H_2	kg_{H_2}/h	0.1[3]	0	46.5
Electrolyser Park 75AEC-25SOEC$_{A}$	H_2O/H_2	kg_{H_2}/h	0.1[3]	0	47.4
H_2 storage tank	H_{2in}/H_{2out}	kg_{H_2}	0	3[5]	0
H_2 storage buried pipes	H_{2in}/H_{2out}	kg_{H_2}	0	9[6]	0
Battery Park	kWh_{in}/kWh_{out}	kWh	0	0[7]	0

[1] Based on [4].
[2] Based on [7] taking the best case scenario of near-term technology development.
[3] Consumption of non-purified water assuming a purification efficieny of 80% based on [7].
Conversion of purified water to hydrogen is stoechiometric (9 kg of water consumed per kg of hydrogen).
[4] From Campion2023 (assuming that heat integration performances will be similar as of 2020).
[5] Based on [9].
[6] Based on [10] assuming same values as of 2020.
[7] Based on communication with industrial partners.

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Table 27: Input Economical Assumptions for 2050

Type of units	Capacity	Investment	Fixed cost	Variable cost
Units	-	€/Capacity installed	€/Capacity installed/y	€/Output
NH_3 plant + ASU - AEC	kg_{NH_3}/h	5084.3[3]	203.4[2]	0.0001
NH_3 plant + ASU - SOEC	kg_{NH_3}/h	5084.3[3]	203.4[2]	0.0001
Desalination plant	kg_{H_2O}/h	134.4[4]	4[5]	0.0003
Waste water plant	kg_{H_2O}/h	107.6[4]	3.2[5]	0
Electrolyser Park AEC	kg_{H_2}/h	24900[6]	2490[7]	0
Electrolyser Park SOEC heat integrated	kg_{H_2}/h	15200	1299.6[8]	0
Electrolyser Park SOEC alone	kg_{H_2}/h	15200	1299.6[8]	0
Electrolyser Park 75AEC-25SOEC$_{HI}$	kg_{H_2}/h	22475	2192.4	0
Electrolyser Park 75AEC-25SOEC$_{A}$	kg_{H_2}/h	22475	2192.4	0
H_2 storage tank	kg_{H_2}	500[9]	15[10]	0
H_2 storage buried pipes	kg_{H_2}	250[11]	7.5[10]	0
OFF_SP379-HH100	kW	1842.8[12]	33.8[12]	0.0025[12]
OFF_SP379-HH150	kW	2118.1[12]	33.8[12]	0.0025[12]
OFF_SP450-HH100	kW	1661.4[12]	33.8[12]	0.0025[12]
OFF_SP450-HH150	kW	1893.3[12]	33.8[12]	0.0025[12]
Battery Park	kWh	180[13]	2.7[14]	0

[1] For a large-scale 133.3 t_{MeOH}/h plant capacity based on [4].
[2] 4% Capex based on [4].
[3] For a very large-scale 190 t_{NH_3}/h plant capacity based on [4] (including ASU).
[4] Using the 2025 best value based on [7].
[5] 3% Capex based on [7].
[6] From [4].
[7] Using 10% Capex based on [4].
[8] 8.55% Capex based on [18].
[9] Based on [16] assuming that compressor and pressurized storage components cost will be half of 2025's costs.
[10] 3% Capex based on [16].
[11] Based on [16] for a working pressure around 100 bars.
[12] From [21].
[13] From [16] assuming low lithium price assuming same values as of 2030.
[14] 1.5% Capex based on [16].

Table 28: Input Technological Assumptions for 2050

Type of units	Input/Output	Capacity	Fuel production rate	Load min	Electrical consumption
Units	-	-	kg output/kg input	% of max capacity	kWh/output
NH_3 plant + ASU - AEC	H_2/NH_3	kg_{NH_3}/h	5.6[1]	10[1]	0.4[1]
NH_3 plant + ASU - SOEC	H_2/NH_3	kg_{NH_3}/h	5.6[1]	10[1]	0.6[1]
Desalination plant	-/H_2O	kg_{H_2O}/h	0	0	0.004[2]
Waste water plant	-/H_2O	kg_{H_2O}/h	0	0	0.004[2]
Electrolyser Park AEC	H_2O/H_2	kg_{H_2}/h	0.1[3]	0	49[1]
Electrolyser Park SOEC heat integrated	H_2O/H_2	kg_{H_2}/h	0.1[3]	0	37.9[4]
Electrolyser Park SOEC alone	H_2O/H_2	kg_{H_2}/h	0.1[3]	0	40[1]
Electrolyser Park 75AEC-25SOEC$_{HI}$	H_2O/H_2	kg_{H_2}/h	0.1[3]	0	46.2
Electrolyser Park 75AEC-25SOEC$_{A}$	H_2O/H_2	kg_{H_2}/h	0.1[3]	0	46.8
H_2 storage tank	H_{2in}/H_{2out}	kg_{H_2}	0	3[5]	0
H_2 storage buried pipes	H_{2in}/H_{2out}	kg_{H_2}	0	9[6]	0
Battery Park	kWh_{in}/kWh_{out}	kWh	0	0[7]	0

[1] Based on [4].
[2] Based on [7] taking the best case scenario of near-term technology development.
[3] Consumption of non-purified water assuming a purification efficieny of 80% based on [7].
Conversion of purified water to hydrogen is stoechiometric (9 kg of water consumed per kg of hydrogen).
[4] From Campion2023 (assuming that heat integration performances will be similar as of 2020).
[5] Based on [9].
[6] Based on [10] assuming same values as of 2020.
[7] Based on communication with industrial partners.

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Table 29: Technical inputs 2030

Type of units	Input/Output	Capacity	Fuel production rate	Load min	Electrical consumption
Units	-	-	kg output/kg input	% of max capacity	kWh/output
MeOH - Biogas - EC	H_2/MeOH	kgMeOH/h	26.4[1]	20[2]	0
MeOH - Biogas - None	BG/MeOH	kgMeOH/h	0.4[3]	20[2]	-0.5[4]
Biogas w H_2	MeOH/BG	kgbiogas/h	1.3[1]	0	0
Biogas wo H_2	MeOH/BG	kgbiogas/h	2.3	0	0
Waste water plant	-/H_2O	kgH_2O/h	0	0	0[5]
Electrolyser Park AEC	H_2O/H_2	kgH_2/h	0.1[6]	0	49.8[2]
Electrolyser Park SOEC alone	H_2O/H_2	kgH_2/h	0.1[6]	0	43.2[2]
H_2 storage buried pipes	-	kgH_2	0	9[7]	0

[1] Based on **Moioli2022**.
[2] Based on [4].
[3] Based on **Ghosh2019** - case 2.
[4] Based on **Ghosh2019**. Power generation is from turbines utilizing excess energy from combustion of biogas processes.
[5] Based on BhmWP12023.
[6] Consumption of non-purified water assuming a purification efficieny of 80% based on BhmWP12023.
Conversion of purified water to hydrogen is stoichiometric (9 kg of water consumed per kg of hydrogen).
[7] Based on [10] assuming same values as of 2020.

Table 30: Economical inputs 2030

Type of units	Investment	Fixed cost	Variable cost
Units	€/Capacity installed	€/Capacity installed/y	€/Output
MeOH plant CCU	17532[1]	701.3[1]	0[2]
MeOH - Biogas - EC	15110.9[3]	655.7[3]	0[3]
MeOH - Biogas - None	18309.9[4]	845.1[4]	0[4]
Waste water plant	107.6[5]	3.2[5]	0[6]
Electrolyser Park AEC	39840[7]	3984[7]	0[8]
Electrolyser Park SOEC alone	39584[9]	3384.4[9]	0[10]
H_2 storage buried pipes	250[11]	7.5[11]	0[12]

[1] For a medium-scale 13.3 t_$MeOH$/h plant capacity based on [4].
[2] 4% Capex based on [4].
[3] Based on **Moioli2022** case 1b.
[4] Based on **Moioli2022** case 1a.
[5] Using the 2025 benchmark value based on BhmWP12023.
[6] 3% Capex based on BhmWP12023.
[7] From [4].
[8] Using 10% Capex based on [4].
[9] Based on [18].
[10] 8.55% Capex based on [18].
[11] Based on [16] for a working pressure around 100 bars.
[12] 3% Capex based on [16].

Table 31: Scenario MeOH Biogas SOEC - Bench fuel

Type of unit	Location	Weight costs vs emissions	Fuel cost(MEuros)	Cost per unit(MEuros)	Production(kton or GWh)	Production cost fuel (Euros/kgfuel)	Production cost fuel (Euros/GJfuel)	Production cost fuel (Euros/MWhfuel)	Production cost per unit (Euros/kg or kWh output)	Av electricity cost(Euros/MWh)
Biogas w H_2	Bornholm	C1_E0	13.1376	13.1376000	36.8000000	0	0	0	0.357000	54.62685
H_2 pipeline to MeOH CCU plant	Bornholm	C1_E0	0.0000	0.0000000	1.1111625	0	0	0	0.000000	54.62685
H_2 pipes compressor	Bornholm	C1_E0	0.0000	0.0000000	0.7291173	0	0	0	0.000000	54.62685
H_2 pipes valve	Bornholm	C1_E0	0.0000	0.0000000	0.7282009	0	0	0	0.000000	54.62685
H_2 storage buried pipes	Bornholm	C1_E0	0.0000	0.2844544	43.9788874	0	0	0	0.006468	54.62685
Charge batteries	Bornholm	C1_E0	0.0000	0.0000000	0.0000000	0	0	0	0.000000	54.62685
Discharge batteries	Bornholm	C1_E0	0.0000	0.0000000	0.0000000	0	0	0	0.000000	54.62685
Batteries	Bornholm	C1_E0	0.0000	0.0000000	0.0000000	0	0	0	0.000000	54.62685

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Table 32: Economical inputs 2030

Type of units	Investment	Fixed cost	Variable cost
Units	€/Capacity installed	€/Capacity installed/y	€/Output
Bamboo2-stage-SOEC	9955.9[1]	1036.7[1]	0[1]
Bamboo1-stage-SOEC	12905[1]	1209.5[1]	0[1]
Wheat2-stage-SOEC	12113.8[1]	1167[1]	0[1]
Wheat1-stage-SOEC	16688.5[1]	1448.5[1]	0[1]

[1] From this study.

Table 33: Technical inputs 2030

Type of units	Input/Output	Capacity	Fuel production rate	Load min	Electrical consumption
Units	-	-	kg output/kg input	% of max capacity	kWh/output
Biomass bamboo 2	DME/BM	kgbiomass/h	1.5[1]	0	0
Biomass bamboo 1	DME/BM	kgbiomass/h	2.2[1]	0	0
Biomass wheat 2	DME/BM	kgbiomass/h	1.8[1]	0	0
Biomass wheat 1	DME/BM	kgbiomass/h	2.5[1]	0	0
Sale of biochar	DME/BC	kgbiochar/h	0.3[1]	0	0
Bamboo2-stage-SOEC	H_2/DME	kgDME/h	7.3[1]	50[1]	0.2[1]
Bamboo1-stage-SOEC	H_2/DME	kgDME/h	11.9[1]	50[1]	0.3[1]
Wheat2-stage-SOEC	H_2/DME	kgDME/h	6.6[1]	50[1]	0.6[1]
Wheat1-stage-SOEC	H_2/DME	kgDME/h	8.5[1]	50[1]	0.8[1]

[1] From this study.

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