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

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1 Introduction

1.1 Context

Denmark has set ambitious goals for decarbonization, aiming to lead the transition away from fossil fuels and towards a sustainable energy system. By compliance with international climate obligations and its national targets in the energy sector, Denmark plans to cut emissions by 70% by 2030 -from 1990 levels- and to be a low-carbon society independent of fossil fuels by 2050.

Despite the country's goals to drastically increase its renewable energy production capacity, electrification alone cannot achieve the desired reduction in greenhouse gases, especially in hard-to-abate sectors such as heavy transport or industry. In these sectors, the adoption of alternative/synthetic fuels becomes essential. These fuels are non-fossil-based energy sources and provide a crucial pathway towards achieving a fully decarbonized energy system.

Alternative fuels are derived from a broad array of energy sources, each with unique production pathways, specific end-use applications, and different socio-economic costs. They can be classified into 3 big groups depending on the energy sources used in their production:

- **Electrofuels (E-fuels)**: They use hydrogen —obtained from the electrolysis of water using renewable energy— as their primary energy source. When carbon is incorporated into e-fuels, it is typically sourced from direct air capture (DAC) processes that also utilize renewable energy.
- **Biofuels**: These are primarily derived from biogenic carbon sources. The main input is biomass, such as agricultural and forestry waste or energy crops. They are characterized by their carbon-neutral cycle, where the CO_2 released upon combustion is balanced by the CO_2 absorbed during the growth of the biomass.
- **E-Biofuels**: These are a hybrid approach that utilizes both biogenic carbon from biomass and hydrogen produced by electrolysis with renewable energy sources (RES). This category merges the production techniques of both biofuels and e-fuels, aiming to utilize the strengths of each and maximize carbon utilization.

Power-to-X (PtX) technologies have a key role in the production of alternative fuels. These technologies serve the purpose of converting electrical energy from various sources -preferably from renewable energy sources- into other forms of energy such as synthetic fuels. Hence, PtX 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 fuel production 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.

Building upon Denmark's ambitious energy policies, Bornholm emerges as a key player in the country's transition towards green energy due to its strategic location and good wind resources. The 'Energy Island Bornholm' project, initiated by the Danish Parliament, envisions Bornholm as a renewable energy hub in the Baltic Sea. This ambitious project aims to construct two offshore wind farms with a combined capacity of 2-3 GW, which includes a dedicated overplanting of 800 MW specifically for Power-to-X applications.

The 'Energy Island Bornholm' project is expected to provide renewable energy to Bornholm and also to be able to export it to mainland Denmark and Germany. This project enhances innovation and economic growth, both locally and nationally.

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It will strengthen Bornholm's security of supply and potentially improve the sector coupling by combining electricity, heating, and transportation in a sustainable way. This will boost the island's energy independence and promote its sustainable development.

This report, titled 'Modelling of scenarios for Power-to-X and alternative fuels production in Bornholm,' dives into the practical aspects of these ambitious goals. It methodically investigates how Bornholm can best utilize its strategic location and resources to align with both local and national green energy objectives. The report focuses on the economical feasibility, efficiency, and potential outcomes of implementing Power-to-X technologies and alternative fuel production on the island, providing valuable insights for transforming Bornholm into a pioneering green energy leader.

1.2 Work package scope and structure

Work package 2 (WP2) combines advanced mathematical modelling, 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 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.

Work Package 2 (WP2), titled 'Modelling of scenarios for Power-to-X and alternative fuels production in Bornholm', was structured into two phases, each with specific tasks and objectives:

Phase 1: Large-scale e-fuel production

Phase 1 of WP2 focused on analyzing the feasibility and implications of large-scale production of hydrogen and ammonia in Bornholm. The objective was not only to satisfy the island's energy demands but also to participate in the potential market of these two fuels in the maritime sector, particularly for the shipping routes near Bornholm.

Phase 1 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 optimization 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 large-scale production of H_2 and NH_3 in the location of Bornholm, running the code under the respective conditions, and filtering and processing the obtained outcomes.

Phase 2: Small-scale e-biofuel production

Building on the groundwork laid in Phase 1, Phase 2 introduces a new dimension to the project, shifting focus to small-scale e-biofuel production. The goal of this phase was to examine the feasibility and implications of a small-scale production of methanol in Bornholm. In this case, methanol would be produced using the biogenic carbon sources from the island (and in some scenarios, also using H_2 from electrolysis), aiming to satisfy a significant share of the local energy/fuel demand.

Similarly to Phase 1, Phase 2 consisted of two main tasks:

• Task 1: Adaptation and expansion of the OptiPlant tool to include the e-biofuel production scenarios: Building on Phase 1, this task involved adapting the OptiPlant model for e-biofuel production scenarios, specifically focusing on methanol synthesis from the biogenic sources in Bornholm. The adaptation and expansion of the model included integrating new technologies and data inputs to comply with the characteristics of methanol production.

• Task 2: Analysis of small-scale e-biofuel production scenarios in Bornholm: This task centred on designing various relevant scenarios for small-scale methanol production in Bornholm. It involved a deep and thorough investigation of different methanol production pathways. A techno-economic assessment for each of these pathways and some relevant scenarios (using one or more of these pathways) was also performed.

WP2 used techno-economical input data from the collaborating partners and Bornholm's resources potential from WP1. In Phase 1, 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 to the discussion of the results obtained by the OptiPlant model.

1.3 Executive Summary

This section provides a summary of the main findings and important conclusions of the WP2 report. *Table* 1 effectively captures the main results from the detailed study of Power-to-X and alternative fuels production scenarios in Bornholm, serving as a direct and accessible point of reference for the report's most critical insights.

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Table 1: Comparative analysis of the key PtX scenarios examined in WP2 Report: evaluation of different key parameters for different fuel production methods under a deterministic sizing approach on a typical/average weather year.

	Fuel prod. cost (BTM) [€/MWh]/[€/kg]	**Fuel prod. costs w/ by-product sales (BTM)[a] [€/MWh]/[€/kg]**	**Fuel prod. costs (Grid-connected) [€/MWh]/[€/kg]**	**OWF overplanting [MW]**	**Amount of prod. fuel [GWh/kton y]**	**Input biogenic C source[b] [kton y]**
Hydrogen (H_2)						
H_2-AEC	137.2/4.6	121.92/4.1	*	754	2200/66	*
H_2-SOEC	121.6/4.1	109.61/3.7	*	654	2200/66	*
Ammonia (NH_3)						
NH_3-AEC	203.3/1.1	184.6/0.9	*	938	2200/426	*
NH_3-SOEC	176.8/0.9	161.5/0.8	121.71/0.6	747	2200/426	*
Methanol (MeOH)						
Scenario 3[1]	196.7/1.1	189.9/1.1	*	103	674.2/121.9	64280 (biogas) + 54550 (wood)
Scenario 4[2]	202.4/1.1	191.7/1.1	*	106	729.4/131.9	64280 (biogas) + 54550 (wood) + 70000 (digestate)

[1] Scenario 3 combines biogas reforming and the two-stage wood gasification, exploiting the maximum potential of both biogas and wood resources available on Bornholm.

[2] Scenario 4 incorporates biogas reforming, the two-stage wood gasification and slow pyrolysis of digestate, representing the biggest exploitation of Bornholm's biogenic carbon resources for methanol production.

[a] The sale prices were set at 20 €/MWh for heat [1], 0.05 €/kg for oxygen [2], and 0.26 €/kg for biochar [3]. The large-scale scenarios (H_2 and NH_3) using AEC produce heat and oxygen as by-products, while the ones using SOEC produce only oxygen due to heat integration at plant level. The small-scale scenarios (MeOH) yield oxygen, heat and biochar as by-products.

[b] The available biogenic carbon resources on Bornholm are displayed in *Table* 21. The assumed purchase prices for each of these inputs is shown in *Table* 20.

Key takeaways of the fuel production competitiveness in Bornholm compared to other global locations

The fuel production costs in Bornholm were evaluated using the same model applied to other locations, including Dakhla (Morocco), Arica (Chile), and Ceduna (Australia). It's important to note that this comparison was based on different assumptions for each location, considering their unique renewable energy sources, power generation profiles, and projected discount rates for 2030. However, this analysis did not incorporate socioeconomic factors such as labor costs, existing infrastructure, political stability, regulatory frameworks, and transportation logistics. These elements are crucial as they can greatly influence the overall feasibility and appeal of each location for investment in fuel production.

• Hydrogen (H_2): Hydrogen production in Bornholm, using exclusively offshore wind energy, is more expensive than the International Energy Agency's (IEA) projections for 2030's Western Europe and exceed those in other locations (Morocco, Chile, Australia) with access to cheaper energy production such as solar or onshore wind. This is mainly influenced by the fact that renewable energy production makes up about half of the costs in PtX hydrogen plants in the study. However, Bornholm's strategic location and the potential of being first-movers offer certain benefits. This is reinforced by the increasing focus on Europe's energy independence and the difficulties in getting public support for onshore wind farms, extensive solar power installations, and power transmission projects, highlighting the reasons to study the feasibility of hydrogen production in Bornholm. The current costs could potentially be brought down through access to grid as shown for ammonia, grid-balancing services and/or local subsidy schemes.

• Ammonia (NH_3): Ammonia production in Bornholm, using exclusively offshore wind energy, is slightly more expensive than the International Energy Agency's (IEA) projections for 2030's Western Europe and exceed those in other locations (Morocco, Chile, Australia) with access to cheaper energy production such as solar or onshore wind. However, this study highlights that if Bornholm's ammonia plant was working connected to the grid (semi-islanded configuration), its costs could match those of the most cost-effective location of a behind-the-meter plant analyzed, which is Morocco. Although Bornholm currently faces connectivity challenges, the upcoming plans to link the island to both Zealand and Germany as part of the energy island project hold promise in this regard. Yet, a major issue for Bornholm is that to produce certified green ammonia its grid emissions should go down.

• Methanol (MeOH): Methanol production in Bornholm at a smaller scale (about 120kton/year) using the island's biogenic carbon sources has been shown to be cost-effective compared to larger-scale plants (600 kton/year) in Morocco, Chile, and Australia. These larger plants are assumed to use Direct Air Capture (DAC) for carbon sourcing, due to the potential unavailability of large quantities of biogenic biomass in these regions. This distinction makes Bornholm's smaller-scale e-biomethanol production more competitive, and this holds true even without accounting for by-product sales in Bornholm.

The current project has provided a first assessment of the feasibility of different types of PtX plants on Bornholm. A recommended next step would be a market analysis assessing the potential sales price followed by a private economic feasibility study taking into account potential subsidies, taxes and tariffs for a specific plant with a determined location. Based on the results of the analyses it is recommended to further explore the possibility of having **semi-islanded operation**, with the possibility to use electricity from the grid to supplement the electricity from the offshore wind power and the PV plant. It should however be ensured that the produced fuel can still be certified as green. Furthermore, it would be interesting to explore the potential of providing balancing services to the grid with flexible operation. The local potential for improving the market for **sales of by-products**, in particular oxygen, should also be explored. Finally, possible **first-mover advantages** should be investigated as these could make particularly hydrogen export to Germany competitive.

2 Optimization model for Power-to-X fuel production: 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 [4] and [5].

In the standard version of the model, the Power-to-X fuel production plant is modelled 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:

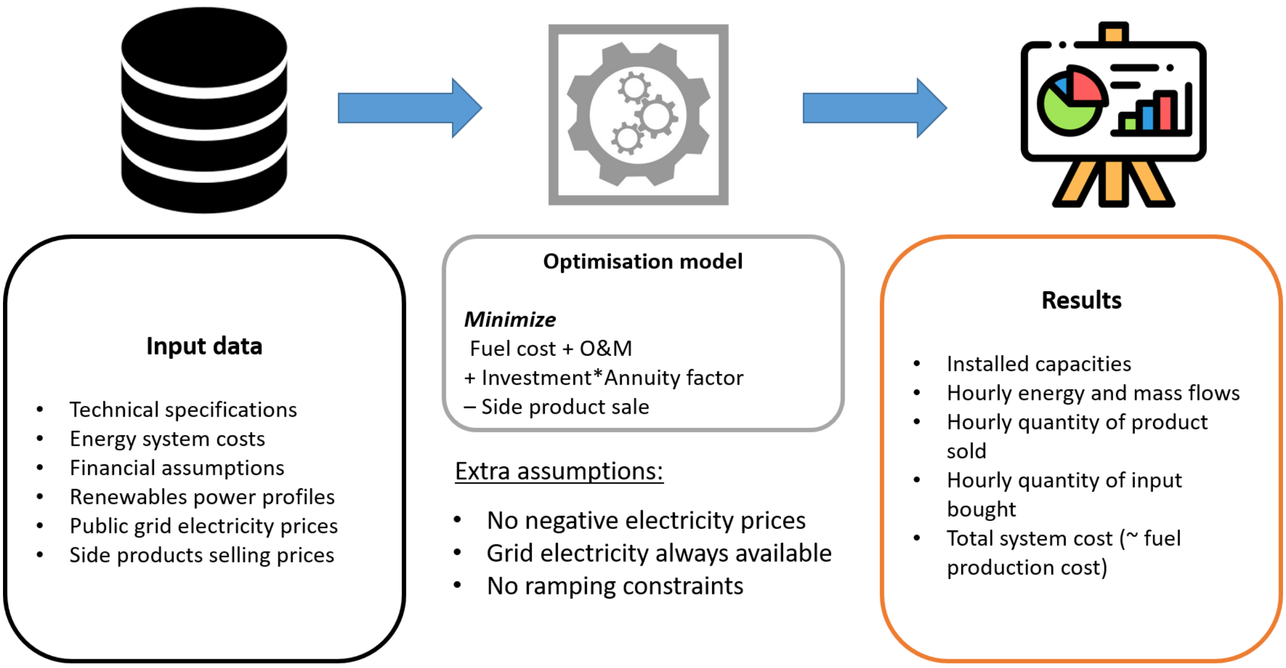

Figure 1: Overview of the OptiPlant optimization model [5]

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 [5]:

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, chemical plants, storage technologies, etc...). *Fuel cost* is the hourly price of electricity and/or the price of biomass resources. *Side product price* is the hourly selling 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 or solar profile: the output power of the wind/solar plant is equal to the normalized power profile multiplied by the installed capacity of wind/solar power.

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

Fuel production constraint: The fuel plant has to produce enough alternative 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 can fall 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 explains schematically the difference between these two approaches used in the model.

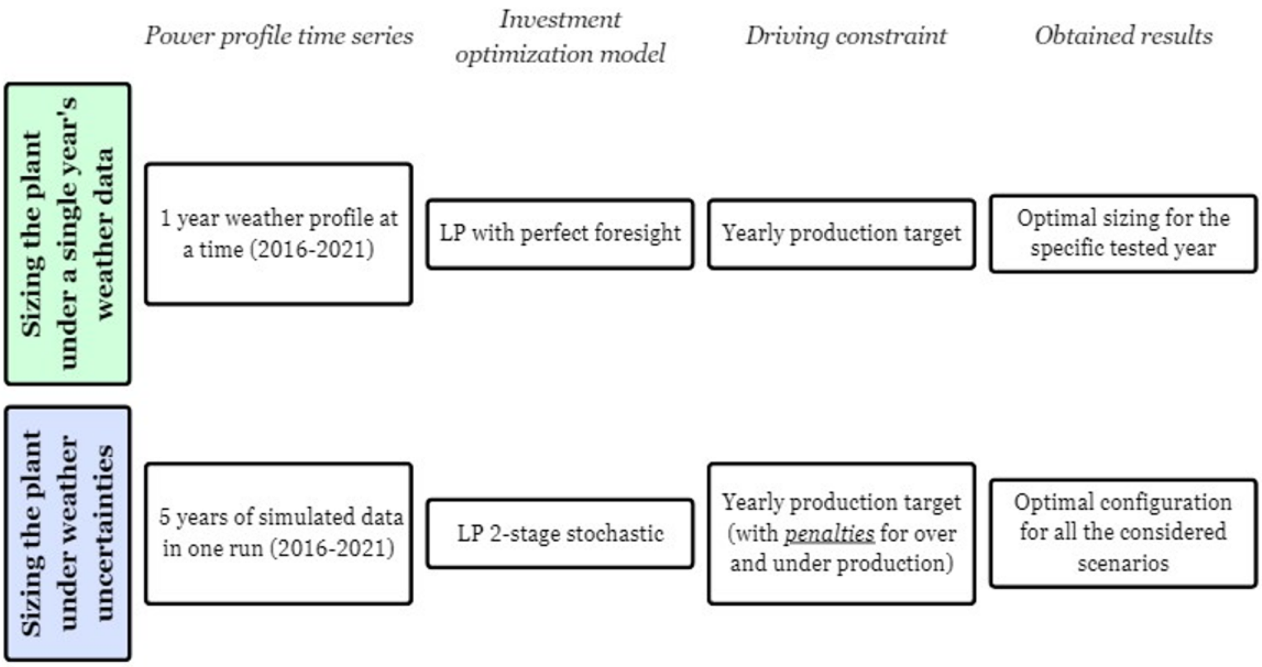

Figure 2: Scheme showing the main differences between the stochastic and deterministic model approaches.

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 Phase 1: Large-scale e-fuel production

3.1 Technical and economic considerations for Power-to-X and e-fuel production at Bornholm

The first phase of WP2 focused on developing and analyzing key scenarios to assess the feasibility of large-scale hydrogen and ammonia production in Bornholm using PtX technologies. The primary goal was to align with Bornholm's energy requirements and explore opportunities in the maritime sector, a key area given the island's strategic location. This section presents a detailed description of the input data and assumptions considered in this first investigation.

3.1.1 Input data

The input data for all of the studied scenarios in Phase 1 of the study 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 and fuel production plants) is detailed in *Table* 2 and *Table* 3 found below. More information on the different plant units can also be found in the rest of the tables in *Section* 7.1 of the *Appendix*.

Table 2: Input technological assumptions for 2030 used in the model for the large-scale PtX plant study

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]	20[1]	0.4[1]
NH_3 plant + ASU - SOEC	H_2/NH_3	kg_{NH_3}/h	5.6[1]	20[1]	0.6[1]
Wastewater plant	$-/H_2O$	kg_{H_2O}/h	0	0	0.0025[2]
Electrolyser Park AEC	H_2O/H_2	kg_{H_2}/h	0.1[3]	0	49.8[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	43.2[1]
Electrolyser Park $75AEC\text{-}25SOEC_{HI}$	H_2O/H_2	kg_{H_2}/h	0.1[3]	0	46.8
Electrolyser Park $75AEC\text{-}25SOEC_{A}$	H_2O/H_2	kg_{H_2}/h	0.1[3]	0	48.1
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 [6].
[2] Based on [7].
[3] Consumption of non-purified water assuming a purification efficieny of 80% based on [7].
Conversion of purified water to hydrogen is stoichiometric (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 [8].
[6] Based on [9] assuming same values as of 2020.
[7] Based on communication with industrial partners.

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Table 3: Input economical assumptions for 2030 used in the model for the large-scale PtX plant study

Type of units	Capacity -	Investment €/Capacity	Fixed cost €/Capacity/y	Variable cost €/Output	Lifetime Years
NH_3 plant + ASU - AEC	kg_{NH_3}/h	6662.2[1]	266.5[2]	0	30[3]
NH_3 plant + ASU - SOEC	kg_{NH_3}/h	6662.2[1]	266.5[2]	0	30[3]
Waste water plant	kg_{H_2O}/h	107.6[7]	3.2[5]	0	15[8]
E.P. AEC	kg_{H_2}/h	39840[9]	3984[10]	0	25[3]
E.P. SOEC heat integrated	kg_{H_2}/h	39584[11]	3384.4[12]	0	25[3]
E.P. SOEC alone	kg_{H_2}/h	39584[11]	3384.4[12]	0	25[3]
E.P. 75AEC-25SOEC$_{HI}$	kg_{H_2}/h	39776	3834.1	0	25[3]
E.P. 75AEC-25SOEC$_{A}$	kg_{H_2}/h	39776	3834.1	0	25[3]
H_2 storage tank	kg_{H_2}	800[13]	24[14]	0	10[15]
H_2 storage buried pipes	kg_{H_2}	250[16]	7.5[14]	0	50[17]
OFF_SP379-HH100	kW	1998.1[18]	37.6[18]	0.0028[18]	30[18]
OFF_SP379-HH150	kW	2296.6[18]	37.6[18]	0.0028[18]	30[18]
OFF_SP450-HH100	kW	1801.4[18]	37.6[18]	0.0028[18]	30[18]
OFF_SP450-HH150	kW	2052.8[18]	37.6[18]	0.0028[18]	30[18]
Battery Park	kWh	180[19]	2.7[20]	0	25[20]

[1] For a large-scale 95 t_{NH_3}/h plant capacity based on [6] (includes ASU).
[2] 4% Capex based on [6].
[3] Based on [10].
[4] Using the 2025 best value from [7].
[5] 3% Capex based on [7].
[6] Based on [11].
[7] Using the 2025 benchmark value based on [7].
[8] From [7].
[9] From [6]. Corresponds to a CAPEX of 800€/kW$_e$.
[10] Using 10% Capex based on [6].
[11] Based on [12] and talks with industry partners.
Corresponds to a CAPEX of 1157€/kW$_e$ for a heat integrated SOEC and 916€/kW$_e$ for non-heat integrated SOEC.
[12] 8.55% Capex based on [12].
[13] Based on [10] (includes compressors).
[14] 3% Capex based on [10].
[15] For high-pressure tanks, life span is around 10 years, depending on the frequency of filling/emptying. Based on [13].
[16] Based on [10] for a working pressure around 100 bars.
[17] Based on [14].
[18] From [15].
[19] From [10] assuming low lithium price.
[20] 1.5% Capex based on [10].

3.1.2 Framework and parameters for scenario development

The selection of the relevant studied scenarios was the result of thorough discussions with all the project's stakeholders. These scenarios took into account a broad range of parameters including: time horizon, plant scale, plant configuration, power supply technologies, renewable energy profiles, electrolyzer technology, type of fuel produced, demand profile type, and sizing method.

Table 4 shows the different aspects considered in the scenarios studied in the Phase 1 investigation (large-scale e-fuel production).

Table 4: Parameters considered when designing the scenarios explored in the study of Phase 1 of WP2 (Large-scale e-fuel production)

	Large-scale PtX plant (Phase 1)
Time horizon	Techno-economic projections for 2030
Plant scale	Large-scale (0.5-1 GW)
Plant configuration	Off-grid (behind-the-meter)
Power supply technologies	Offshore wind -only-
Renewable energy profiles	Weather data from 2016 to 2021
Electrolyzer technologies	AEC, SOEC and Mix (75%AEC-25%SOEC)
Fuel produced and synthesis routes	Hydrogen and Ammonia (single route for each fuel)
Demand profile type	Yearly demand
Sizing method	Deterministic and Stochastic

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

Time horizon

The year 2030 was selected as the time frame for the two WP2 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% -from 1990 levels- 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 is 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.

Plant configuration

In terms of plant configuration, it is assumed that the large-scale scenarios operate 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. While it is assumed that the Power-to-X plant owner also owns a share of the renewable power assets and can use them freely, the investment and operational costs associated with these assets are the responsibility of the PtX plant owner. This 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 due to the broad mix of energy sources in the grid.

Figure 3 presents the power supply and plant configuration for the large-scale PtX plant investigation.

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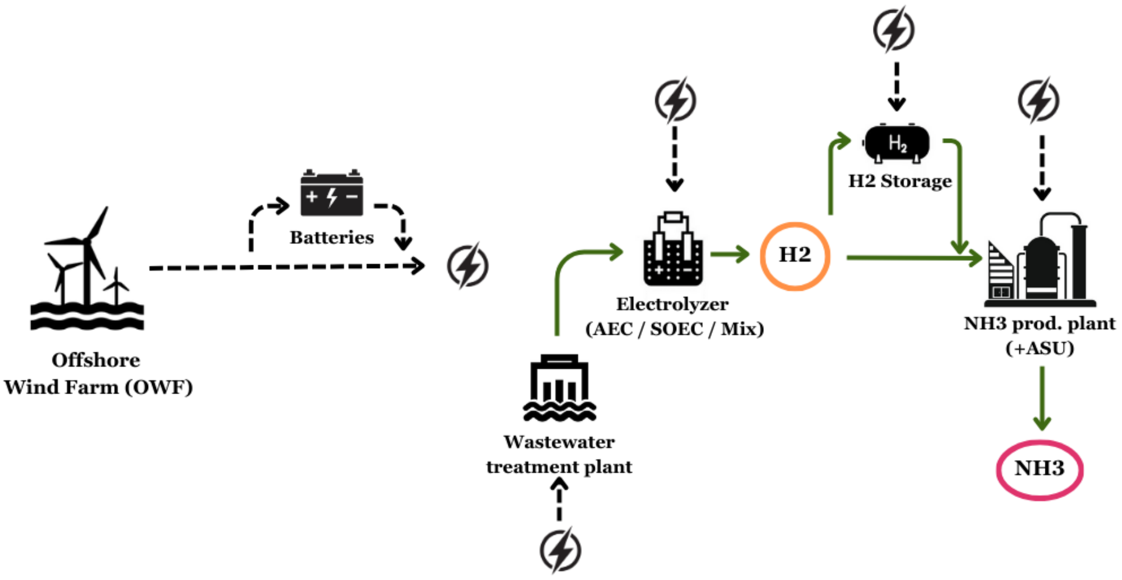

Figure 3: Scheme showing a simplified behind-the-meter (BTM) power supply configuration of the Power-to-X plant considered in the model for the large-scale study [5].

Power supply technologies

The simulated scenarios for the large-scale study, focused on hydrogen and ammonia production, 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. In this investigation, the OWF is anticipated to be around 1 GW in scale, with no specific upper limit placed on its capacity.

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 distinct sources. Wind profiles were sourced using the CorRes tool [16], while solar data was acquired from renewables.ninja [17],[18]. 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 in the large-scale PtX plant modelling: Alkaline Electrolyzer Cells (AEC), Solid Oxide Electrolyzer Cells (SOEC), and a combined configuration of 75% AEC + 25% SOEC (Mix).

The techno-economic characteristics used for the electrolyzers in the model are collected in *Table* 2 and *Table* 3 (also found in *Section* 7.1 of the *Appendix*). Each technology has upsides and downsides from a techno-economic standpoint. The efficiency of the electrolyzers varies with the load, as further detailed in the load curve included in *Figure* 25 in the *Appendix*. Initially, the model employed a piecewise linearization approach to represent this load-dependent efficiency. However, subsequent analysis revealed that efficiency variation with load had a minimal impact on the overall results. Therefore, for simplicity and practicality, the electrolyzer's efficiency was treated as approximately constant across different scenarios. This simplification yielded consistent results without compromising the accuracy of the model.

Fuel produced and synthesis routes

The large-scale PtX plant study focused on producing hydrogen and ammonia, both categorized as e-fuels. The considered synthesis routes for these two fuels were as follows:

- Hydrogen (H_2): the hydrogen production route involved the electrolysis of water. In this process, water molecules are split into hydrogen and oxygen through an electrolyzer, with the hydrogen gas being captured for use as fuel (oxygen can also be stored as a co-product for other uses). When the electrolysis process is powered by renewable energy sources, specifically the offshore wind farm (OWF) in this study, the resulting hydrogen is referred to as green hydrogen.

- Ammonia (NH_3): the ammonia synthesis process is based on the combination of green hydrogen (produced from electrolysis as above) with nitrogen. The nitrogen is obtained from an Air Separation Unit (ASU), where it is separated from atmospheric air. In the subsequent step, hydrogen and nitrogen gases are mixed in a chemical reactor. Under specific temperature and pressure conditions, these gases undergo the Haber-Bosch process, a well-established method for ammonia synthesis. This method is the most widely used to produce ammonia due to its high efficiency. Both the ASU and the ammonia production plant in this setup are also powered by green energy sourced from the OWF.

The techno-economic characteristics used for the different units involved in the fuel production for the described pathways are included in *Table* 2 and *Table* 3 (also included in *Section* 7.1 of the *Appendix*).

Fuel demand type

The fuel demand projected in this study is based on an annual basis. More specifically, the Phase 1 investigation assumed a hydrogen demand of 66kt/year and an ammonia of 426kt/year. This corresponds to approximately 2200 GWh of fuel.

To understand the magnitude of 2200 GWh of fuel, it is helpful to roughly compare this figure with the energy consumption in different sectors of Bornholm, as detailed in the Bornholm Energy Strategy [19]. 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.

Finally, it has to be noted that no constraints related to the storage or transport of the produced e-fuels were considered in 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. Both deterministic and stochastic model approaches were used in Phase 1 to account for the high variability on the offshore wind power profiles.

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3.1.3 Scenario design and resulting scenarios

The different combinations of all the considered aspects mentioned above resulted in a set of unique scenarios that were thoroughly examined in the large-scale PtX plant investigation. As a result, 36 deterministic scenarios and 6 stochastic scenarios were run through the model. For the deterministic case, these numbers arise from the combination of 6 weather years' data (2016 to 2021), 3 types of electrolyzer (AEC, SOEC, Mix), and 2 types of produced fuel (H_2 and NH_3). 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 (H_2 and NH_3).

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 the different parameters considered in the model. The obtained results for these scenarios are presented in the following section.

3.2 Results and discussion

This section presents and discusses the outcomes derived from simulating the scenarios developed in Phase 1 for the large-scale Power-to-X (PtX) plant using the OptiPlant tool. As outlined in previous sections, this study focused on the feasibility and implications of large-scale production of hydrogen and ammonia in Bornholm. By conducting both deterministic and stochastic analyses, various scenarios and configurations to optimize production costs, plant size, and resource utilization were explored.

The results presented in this section offer detailed insights into optimal plant sizing and key economic indicators, including total annualized system costs and fuel production costs for each scenario. Additionally, extra assessments were conducted, including water and land availability, heat integration, hydrogen export costs, sensitivity analysis on critical parameters, analysis of location competition, and considerations for grid connection of the plants. These findings highlight Bornholm's potential as a significant player in the renewable hydrogen and ammonia market, especially considering the projected market demand for these fuels on the island.

3.2.1 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 annualized 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 several parts. First, the optimal plant sizing for the selected scenarios and the cost analysis under the given weather conditions are presented. Subsequent sections provide additional findings on water availability, hydrogen export costs, sensitivity analysis, and location competition. Each of these factors plays a crucial role in the successful development and operation of the Power-to-X plant.

3.2.1.1 Optimal PtX 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* 5.

Table 5: Optimal sizing for the large Power-to-X plant units for different scenarios under the deterministic analysis (H_2 and NH_3). Demand settled at 66kt/year for H_2 and 426kt/year for NH_3.

	H_2-AEC	H_2-SOEC	H_2-MIX	NH_3-AEC	NH_3-SOEC	NH_3-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 [t H_2/h]/[MW_i]						
Best-case year (2017)	13.8/688.8	13.8/597.5	13.8/666.0	15.9/796.3	15.8/683.9	15.9/767.5
Worst-case year (2018)	16.0/799.5	16.0/692.1	16.1/772.8	18.3/911.3	17.9/775.4	18.2/874.9
Typical/average year (2020)	14.3/715.6	14.3/620.8	14.3/691.9	16.4/818.2	16.2/700.3	16.4/788.7
Wastewater treat. plant [m^3 H_2O/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
NH_3 prod. plant (+ ASU) [t NH_3/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
H_2 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.

The optimal sizing results for the Power-to-X plant units detailed in *Table* 5 reveal distinct requirements for each considered scenario, adapting to the specific demands for hydrogen (H_2) and ammonia (NH_3).

The results demonstrate that the capacity for hydrogen and ammonia production units varies depending on the type of electrolysis process used, with AEC (Alkaline Electrolysis Cell) generally necessitating larger capacities and SOEC requiring smaller ones due to the better efficiency of the latter. When using a MIX electrolyzer, overall the installed capacities appear to be in between the AEC and the SOEC ones.

The wastewater treatment plant capacities reflect the water demands for electrolysis, remaining constant across the scenarios when producing the same fuel in the same weather year.

Batteries and hydrogen storage play a crucial role in balancing the intermittent nature of wind energy, with their capacities varying significantly across different years, suggesting a higher demand for energy storage in less windy years.

The hydrogen and ammonia production costs and the respective total annualized system cost for each of the studied scenarios were also examined under two distinct approaches:

- Standard cost analysis: This analysis is conservative as it mainly analyzes the total system costs and the fuel production costs for all the studied scenarios without considering the revenues from by-products.

- Cost analysis with by-products selling revenue: In this more optimistic approach, the selling of by-products from hydrogen and ammonia is considered, providing a revised economic evaluation. In the context of the production of both fuels, the monetized by-products consist of heat and oxygen. However, it is important to notice that only the surplus heat aligns with the scale of Bornholm's heat demand. The production of oxygen notably surpasses the island's market capacity. Given the relatively small local market for oxygen, it becomes less practical to rely on its sale as a significant revenue source in the economic evaluation of hydrogen and ammonia production in Bornholm.

STANDARD COST ANALYSIS

For the **standard cost analysis**, the fuel production cost and total annualized system cost for each of the selected relevant scenarios were also examined. *Figures* 4, 5, and 6 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 annuity values considered for each of the PtX plant facilities are displayed in *Section* 7.1 of the *Appendix*. The corresponding fuel production costs are represented by black dots plotted on the secondary y-axis in €/MWh. These costs are calculated by dividing the total annualized system cost by the energy produced yearly. The numerical values annotated above each dot specify the fuel production costs, both in terms of €/MWh and €/kg. It is assumed that the energy densities for H_2 and NH_3 are 33.3 MWh/ton and 5.2MWh/ton, respectively [20].

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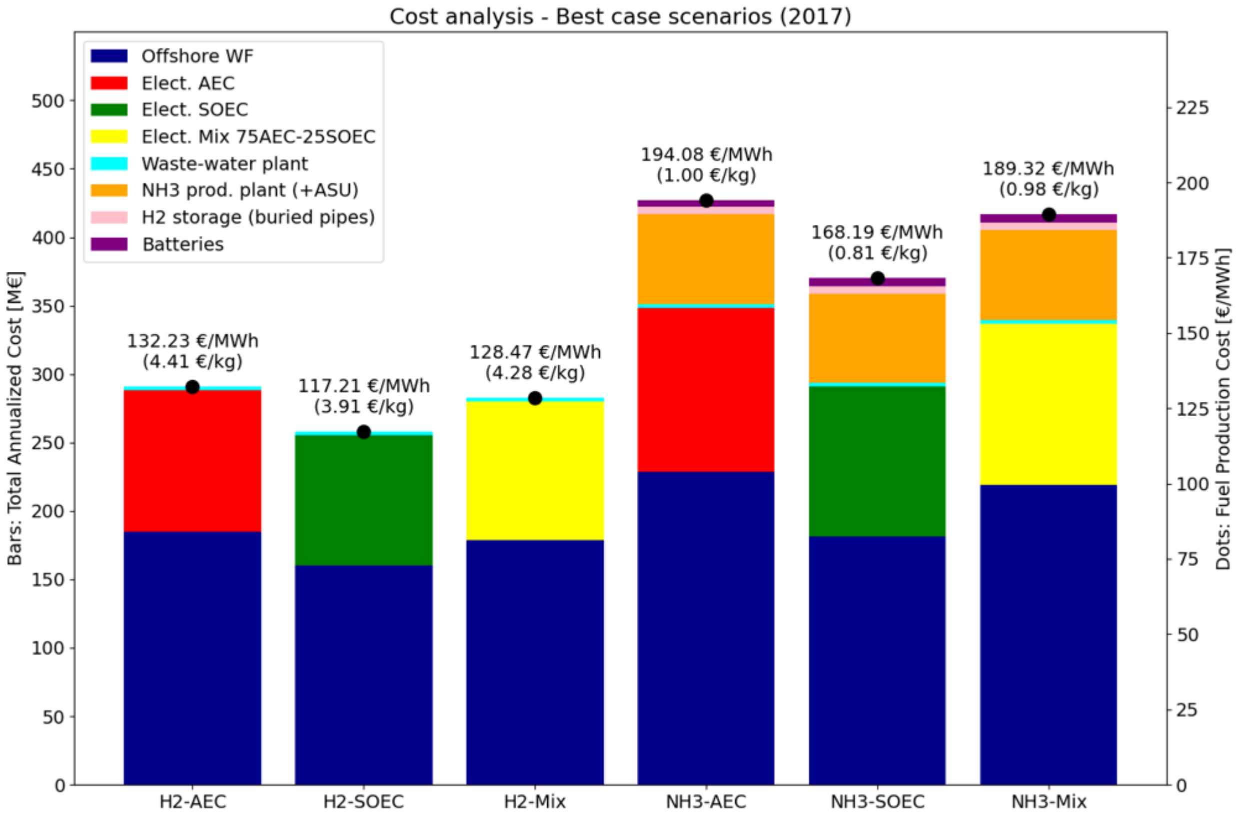

Figure 4: Comparative cost analysis for the scenarios of the best-case weather year -i.e. minimum costs- (2017). **Standard cost analysis.**

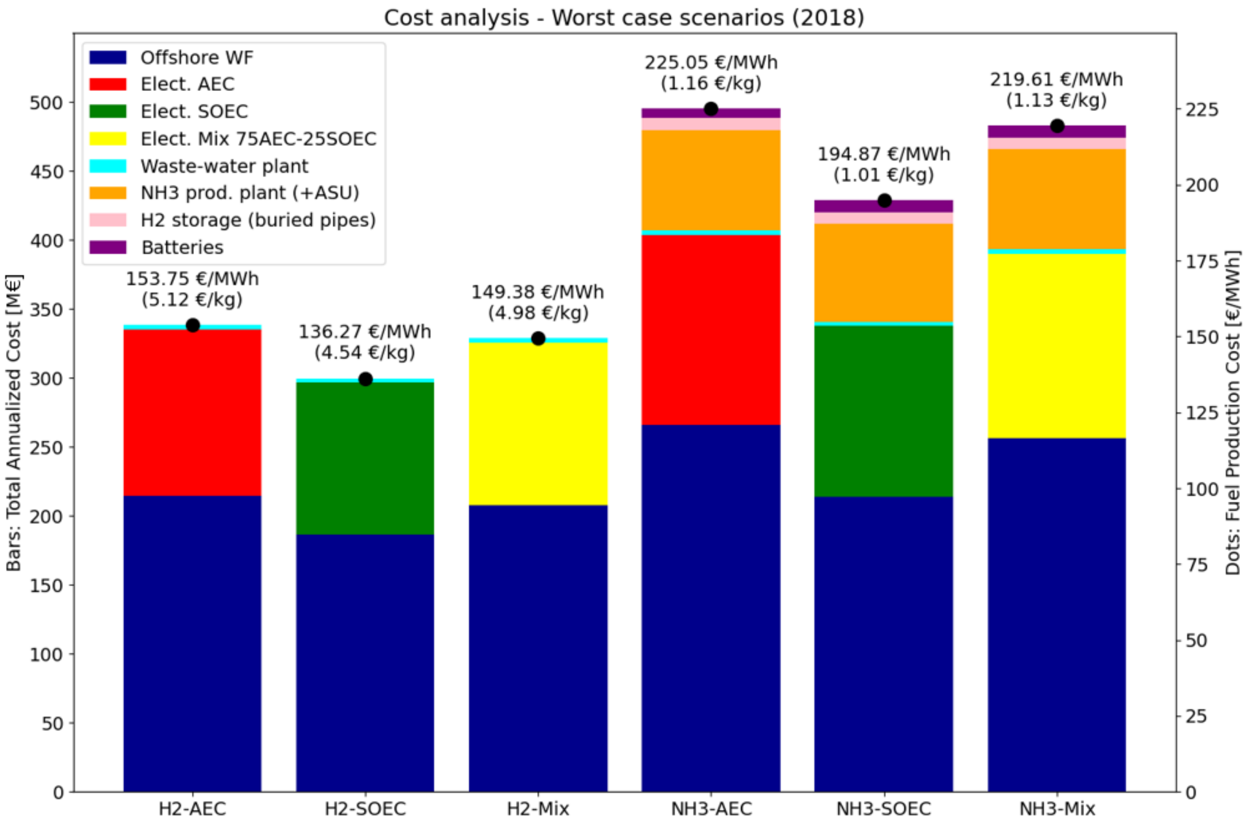

Figure 5: Comparative cost analysis for the scenarios of the worst-case weather year -i.e. maximum costs- (2018). **Standard cost analysis.**

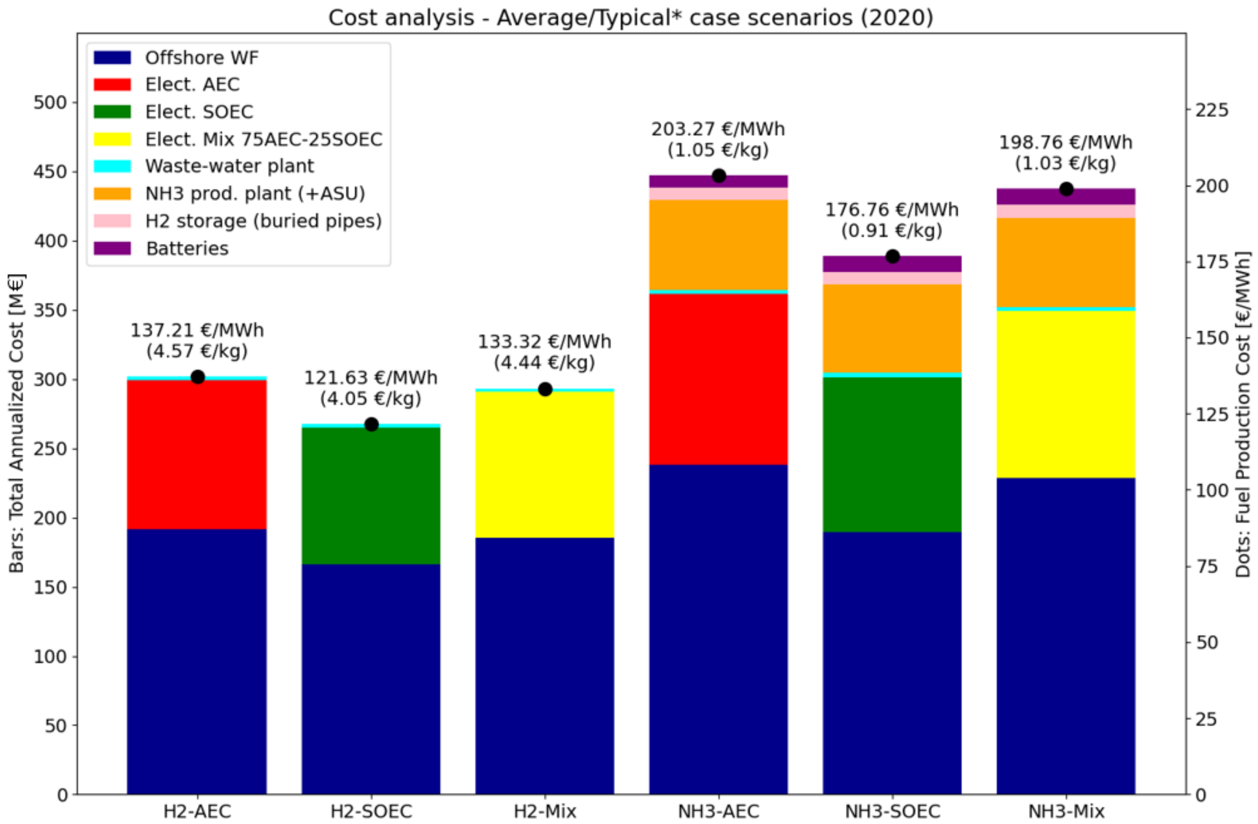

Figure 6: Comparative cost analysis for the scenarios of the average/typical weather year (2020). **Standard cost analysis.**

In addition to the graphs shown above, *Table* 6 provides a numerical summary of the total annualized system cost and *Table* 7 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 clearer visualization of the costs of the different plant configurations under various weather conditions.

Table 6: Breakdown of the total annualized system cost for the large Power-to-X plant by unit for different scenarios under the deterministic analysis (H_2 and NH_3) -all costs are in [M€/year]-. **Standard cost analysis.** Demand settled at 66kt/year for H_2 and 426kt/year for NH_3.

	H_2-AEC	H_2-SOEC	H_2-MIX	NH_3-AEC	NH_3-SOEC	NH_3-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
NH_3 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
H_2 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 [M€/year]						
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

From the results displayed in *Figures* 4, 5, 6, and *Table* 6, it can be observed that the offshore wind farm represents the largest cost component across all scenarios. This is followed by the cost of the electrolyzer.

In terms of the overall cost distribution, and taking the average/typical weather year, the offshore wind farm contributes by around 63% of the total costs in the hydrogen scenarios and 50% in the ammonia scenarios. The electrolyzer accounts for 36% of the total costs in the hydrogen scenarios and 27% in the ammonia scenarios. Finally, the ammonia production plant accounts for approximately 14% of the cost across the ammonia-producing scenarios. The remaining percentage of the total cost is distributed among the other units.

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Table 7: Fuel production cost of different scenarios under the deterministic analysis (H_2 and NH_3). **Standard cost analysis.** Demand settled at 66kt/year for H_2 and 426kt/year for NH_3.

	H_2-AEC	**H_2-SOEC**	**H_2-MIX**	**NH_3-AEC**	**NH_3-SOEC**	**NH_3-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

Analyzing the data presented in *Table* 7 and taking the typical/average weather year as the base case, it is clear that the most cost-effective option for hydrogen production is the H_2-SOEC scenario at 121.63 €/MWh, while the H_2-AEC scenario is the most costly at 137.21 €/MWh. The cost difference between these two scenarios is approximately 11.37%. Regarding ammonia production in a typical/average weather year, a similar pattern is observed: NH_3-SOEC is the least expensive at 176.76 €/MWh while NH_3-AEC's is the most expensive at 203.27 €/MWh. The percentage difference between these two is 13.04%.

It should be noted that in the values above corresponding to the standard cost analysis, the potential revenue from by-products like heat or oxygen was not considered. This factor is evaluated for the average/typical weather year (2020) in the following section to evaluate the potential impact this could have on the final cost of the system and the fuel production cost.

COST ANALYSIS WITH BY-PRODUCT SALE -*Typical/average weather year (2020)*-

For the **cost analysis with by-products selling revenue**, *Table* 8 displays a numerical breakdown of the revenues from the sale of heat and oxygen for the typical/average weather year (the costs of the different units are the same as the ones found in *Table* 6). *Table* 9 shows the total amount of produced by-products and the fuel production costs for all scenarios in the large-scale PtX plant study, incorporating by-product sale revenues. Here, the fuel production costs are equal to the total annualized system cost, both positive and negative (including by-product sale revenues), per energy produced yearly. Energy densities for H_2 and NH_3 are considered at 33.3 MWh/ton and 5.2MWh/ton, respectively [20]. Selling prices for the by-products were sourced from literature or provided by project partners. The sale prices were set at 20 €/MWh for heat [1], and 0.05 €/kg for oxygen [2]. These values can vary due to different reasons and should be used as indicative values. This analysis aims to provide a general understanding of the possible reduction in fuel cost when by-products are sold.

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Table 8: Breakdown of the by-product sale revenues for the large Power-to-X plant by unit for different scenarios on a typical/average weather year (2020) under the deterministic analysis (H_2 and NH_3) -all costs are in [M€/year]-. **Cost analysis with by-product sales**. The costs of the plant units are the same as the ones displayed in *Table* 6. Demand settled at 66kt/year for H_2 and 426kt/year for NH_3.

	H_2-AEC	H_2-SOEC	H_2-MIX	NH_3-AEC	NH_3-SOEC	NH_3-MIX
...						
Heat sale						
Typical/average year (2020)	-7.49	0	-5.62	-8.70	0	-6.53
Oxygen sale						
Typical/average year (2020)	-26.40	-26.40	-26.40	-30.67	-30.67	-30.67
'New' TOTAL (w/ by-product sale) [M€/year]						
Typical/average year (2020)	267.98	241.18	261.27	407.85	358.23	400.11

From the results displayed in *Table* 8, it can be noted that the revenue generated from selling oxygen significantly surpasses that from selling excess heat. Notice that for the scenarios using SOEC, there is no excess heat produced, as it is assumed that all the processes of the PtX plants using this technology are heat-integrated.

Table 9: Fuel production cost of different scenarios on a typical/average weather year (2020) under the deterministic analysis (H_2 and NH_3). **Cost analysis with by-product sales.** Demand settled at 66kt/year for H_2 and 426kt/year for NH_3.

	H_2-AEC	H_2-SOEC	H_2-MIX	NH_3-AEC	NH_3-SOEC	NH_3-MIX
Fuel production cost [€/MWh]/[€/kg]						
Typical/average year (2020)	121.92/4.05	109.61/3.65	118.92/3.96	184.61/0.96	161.54/0.84	180.77/0.94
By-products						
Heat [GWh/year]	374.62	0	280.96	435.21	0	326.40
Oxygen [kton/year]	528.00	528.00	528.00	613.40	613.40	613.40

Inspecting the results in *Table* 9, one can observe that after the sale of by-products, the scenarios using SOEC remain the cheapest option for hydrogen and ammonia production at 109.61 €/MWh and 161.54 €/MWh, respectively (despite not having excess heat sale revenues). The production cost reduction for the different scenarios when selling both heat and oxygen compared to the standard cost analysis ranges from 9-11%

When considering only excess heat sales, the standard fuel production costs are reduced by smaller percentages in comparison to the standard cost analysis (1.5%-2%).

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In this analysis, the sale of the by-products 'heat' and 'oxygen' was considered at 20 €/MWh for heat [1], and 0.05 €/kg for oxygen [2]. As previously mentioned, It should be emphasized that only the excess heat produced matches Bornholm's heat demand scale and only at the annual level. Full use of the excess heat would require large-scale heat storage which could be infeasible. With regard to oxygen production, it greatly exceeds the island's current annual market needs. Due to the limited local demand for oxygen, its sale as a major revenue stream should be taken with caution in the economic assessment of hydrogen and ammonia production in Bornholm, but there is a clear potential for attracting oxygen-demanding industries if hydrogen production is established.

3.2.1.2 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 m^3 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 *Table* 53 found in *Section* 7.3 of the *Appendix*.

The 'maximum water demand' from a large-scale PtX plant for the different months throughout the year is detailed in *Table* 54 also found in *Section* 7.3 of the *Appendix*

For a 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 *Figure* 7. In this graph, the monthly wastewater production of different plants in Bornholm for the year 2021 (*Table* 53 in the *Appendix*) 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* 54 in the *Appendix*) 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.

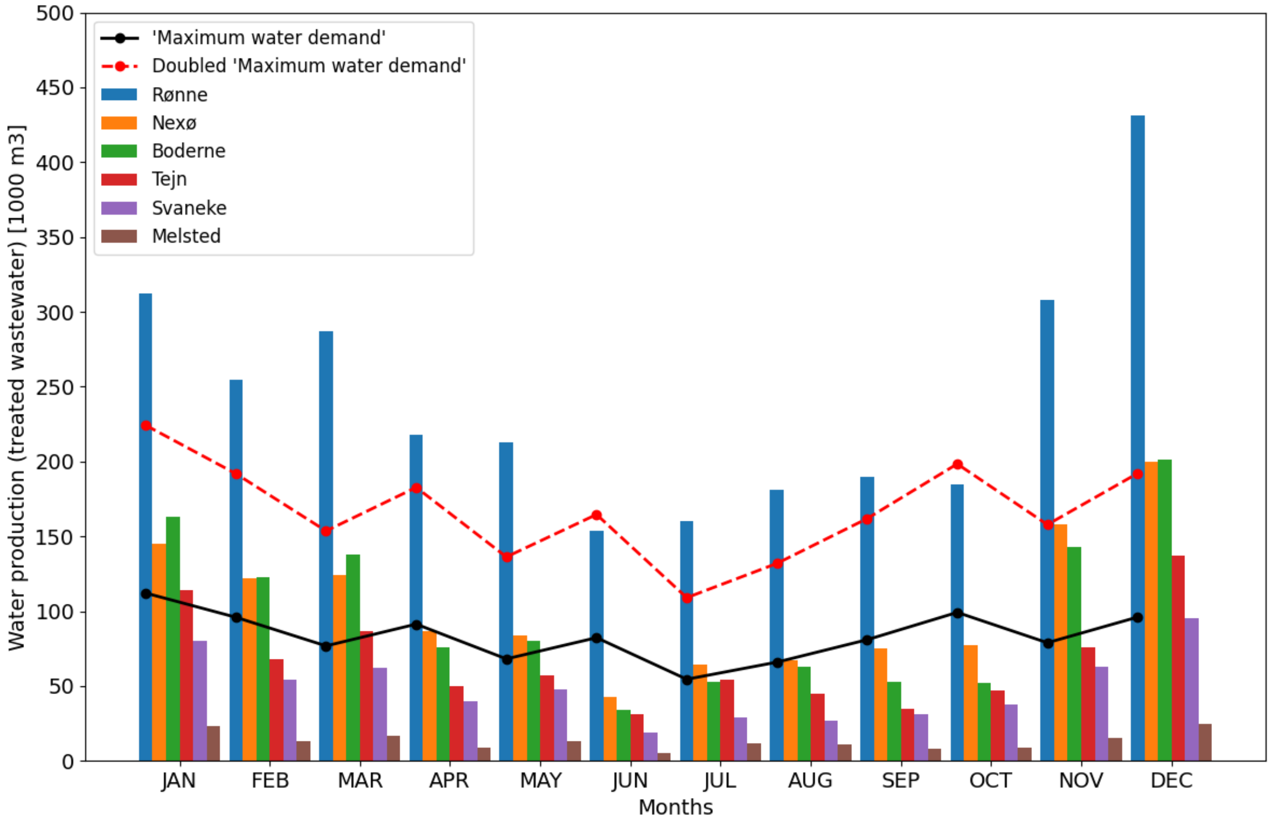

Figure 7: Monthly wastewater production from different treatment plants in Bornholm for 2021 compared with the 'maximum water demand' of the PtX NH_3 plant (black line) and a hypothetical 'doubled maximum water demand' scenario (dashed red line).

As seen in *Figure* 7, the wastewater treatment plant in Rønne can meet the maximum water demand of the Power-to-X plant for most of the months. In fact, Rønne wwtp could also provide double the maximum demand, showing robustness and potential system scaling. Nexø and Boderne plants could meet the regular maximum demand during the rainy seasons. For the months in which none of the plants cannot supply the totality of the water needed, a combination of wastewater plants could be used.

3.2.1.3 Assessment of heat integration from the large-scale PtX plant into the District Heating system

This section investigates the potential of integrating the excess heat from the large-scale hydrogen and ammonia production processes into Bornholm's district heating system. The study aims to give an overview of how effectively this excess heat can fulfil a significant part of the island's heating demands. WP4 looked into district heating in more detail. Utilizing the surplus heat can enhance the energy efficiency of the PtX plant and potentially reduce hydrogen and ammonia production costs. Additionally, this integration plays a key role in evaluating the extent to which Bornholm can rely on sustainable methods to satisfy its heating requirements, supporting the island's goals for energy self-sufficiency and ecological balance.

However, it is important to note that the exact temperatures of the excess heat generated by the various processes within the PtX plant are not known with precision. This uncertainty introduces variability in the costs associated with adjusting this heat to temperatures that are useful for district heating. Therefore, while evaluating the integration of excess heat is a promising approach for increasing sustainability and supporting Bornholm's energy self-sufficiency goals, the economic and technical feasibility of this process should be explored in more detail.

Currently, Bornholm's district heating system requirements are met by seven heat-producing sources distributed across the island, supplying approximately 336 GWh of heat annually (see *Figure* 26 in *Section* 7.4 of the *Appendix*).

To ensure a more realistic understanding of Bornholm's heating requirements, this analysis evaluated the island's heat demand on a monthly basis over the year. The data regarding monthly heat production from various sources on Bornholm was obtained from BEOF and WP4. The study's approach involved modelling the heat demand dynamics for all sources assuming similar operational patterns as the Nexø heat plant, for which data were available. The monthly heat supply figures for each plant on the island are comprehensively detailed in *Table* 56 found in *Section* 7.4 of the *Appendix*.

Table 57 in *Section* 7.4 of the *Appendix* outlines the excess heat produced in the hydrogen and ammonia synthesis for each of the 6 large-scale deterministic scenarios, throughout the year.

The comparison between heat supplied by Bornholm's seven heat-producing facilities and the potential heat output from various hydrogen and ammonia production scenarios is visualized in *Figure* 8. The figure uses distinctive bars to represent the combined monthly heat production of all Bornholm's plants for 2021, as listed in *Table* 56 in the *Appendix*. Overlaid lines in the graph indicate the potential excess heat from the H_2 and NH_3 production scenarios detailed in *Table* 57 in the *Appendix*, providing a clear visual representation of these comparative data.

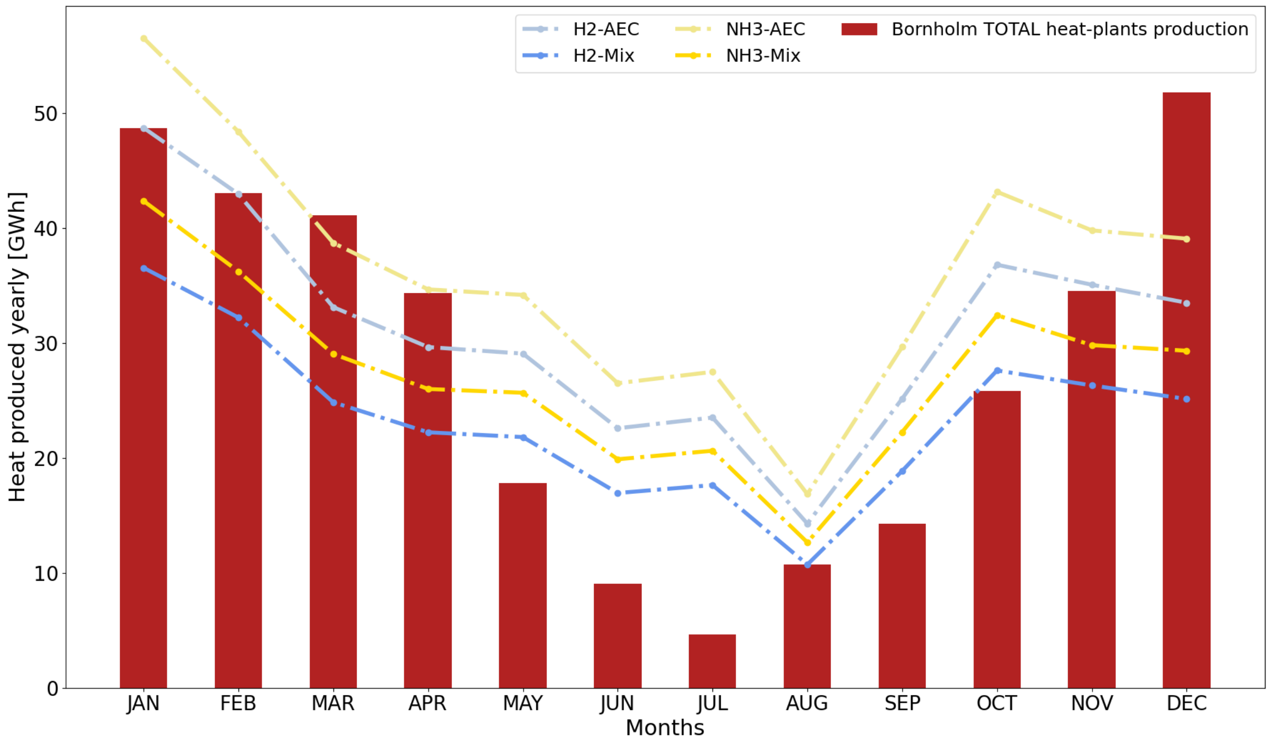

Figure 8: Monthly heat production from different heat plants in Bornholm for 2021 (bars) compared with the potential excess heat from the methanol production scenarios (lines) .

In *Figure* 8, it can be observed that the excess heat from hydrogen and ammonia production scenarios could significantly impact Bornholm's heat production landscape, particularly if the heating grids were connected. All scenarios (except the ones using a SOEC electrolyzer) are projected to generate similar monthly heat amounts as the combination of the current 7 heat-production facilities. Notably, the heat output from these scenarios remains relatively consistent throughout the year, not matching the timings from the island's seasonal heat demand pattern.

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This uniformity is only interrupted in August, which is used as a maintenance/shutdown period for the PtX plant in the model. In order to supply enough heat for Bornholm during the winter months, another heat source (one of the plants) or a large heat storage would however be required. However, as previously mentioned, the exact temperatures of the excess heat from the PtX plants are not determined with precision. This results in an uncertain cost factor for adapting this heat to meet the requirements of the district heating system. Therefore, the integration of this excess heat into Bornholm's heating framework would require a deeper economic and technical assessment.

3.2.1.4 Export costs: Hydrogen transport via pipeline to Germany

The potential of exporting hydrogen from Bornholm to neighbouring 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 [21], but EHB suggests operating them at 7 GW and 13 GW to optimize costs [22]. In conclusion, the capacity of the pipelines in question are not a limiting factor for the proposed hydrogen production on Bornholm. Their eventual size would rather be influenced and determined by the combined future hydrogen production in the Baltic Sea.

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 planned to begin operation in 2027. It will have an import capacity of 10GW, with plans to potentially extend it to 20GW [23].

A study from EHB, [24], provides estimates for hydrogen pipeline costs. The estimated levelized cost for transporting hydrogen through repurposed underground offshore pipelines in Europe is approximately 0.17-0.32 €/kg_{H_2} per every 1000 km. For new offshore pipelines, the cost of transportation is 0.32-0.60 €/kg_{H_2}/1000km depending on the size of the pipeline. The connection from Bornholm to Germany will likely be a new pipeline, so the second range of values should be used in the export costs. For hydrogen pipelines onshore the range of costs are 0.09-0.25 €/kg_{H_2}/1000km for repurposed pipes and 0.19-0.80 €/kg_{H_2}/1000km for new hydrogen pipes [24].

A likely cost of transporting hydrogen from Bornholm to Germany can be given based on the presented levelized costs of hydrogen transportation from EHB, [24]. The first 140 km of offshore pipes will cost around 0.60 €/kg_{H_2}/1000km assuming the pipe is a new, medium-sized hydrogen pipeline. The hydrogen can be assumed to be transported at a cheaper cost through the rest of Germany/Europe. With a 1000 km pipeline from Bornholm all of Germany can be reached, suggesting that the likely maximum additional cost of transport is **0.6 €/kg_{H_2}**. This adds around 15% cost increase to the LCOH for hydrogen produced in Bornholm. This estimation is uncertain as hydrogen infrastructure is still an evolving technology, and the pipeline financing is dependent on future investment in hydrogen production in the Baltic Sea, but it does provide somewhat of an upper bound of hydrogen transportation costs from Bornholm to the European hydrogen demand centres.

3.2.1.5 Sensitivity analyses on the large-scale ammonia plant.

This section presents sensitivity analyses of key assumptions of the base case scenario for the large-scale ammonia plant, particularly focusing on those with the highest uncertainty. The base case used for comparison corresponds to the scenario NH_3-AEC for the typical/average year (2020). This section aims to identify which assumptions most significantly impact the obtained outcomes (and by how much), specifically concerning the production costs of green ammonia. Two critical factors were analyzed: the type of hydrogen storage used and the minimum load capacity of the ammonia plant. The benchmark minimum load of the ammonia plant is 20% and the choice of hydrogen storage is buried pipes. The case where no battery storage is available was also examined and it was shown that the plant operation was infeasible unless it had access to power from the grid or all its components were fully flexible.

- Intermediary hydrogen storage: In the base case investigation, the model chose that the best hydrogen storage system was the buried pipes. Even though this technology showed better techno-economic characteristics, it is not as mature nor easy to implement as using overground hydrogen tanks (or no storage at all). That is why the sensitivity analysis examined the options of using overground hydrogen tanks or not having any storage capacity for hydrogen and having a direct supply line from the electrolyzer to the ammonia plant.

- Ammonia plant flexibility: The benchmark technology assessment for 2030 concluded that the minimum load of the ammonia production plant is 20% of the rated load. The flexibility of the plant's operation influences the need for intermediary storages as well as the necessary power production size significantly, as the plant is powered by a variable power source, wind. Hence, the impact of the plant either being fully flexible or having a minimum load of 40% (current benchmark value) is assessed.

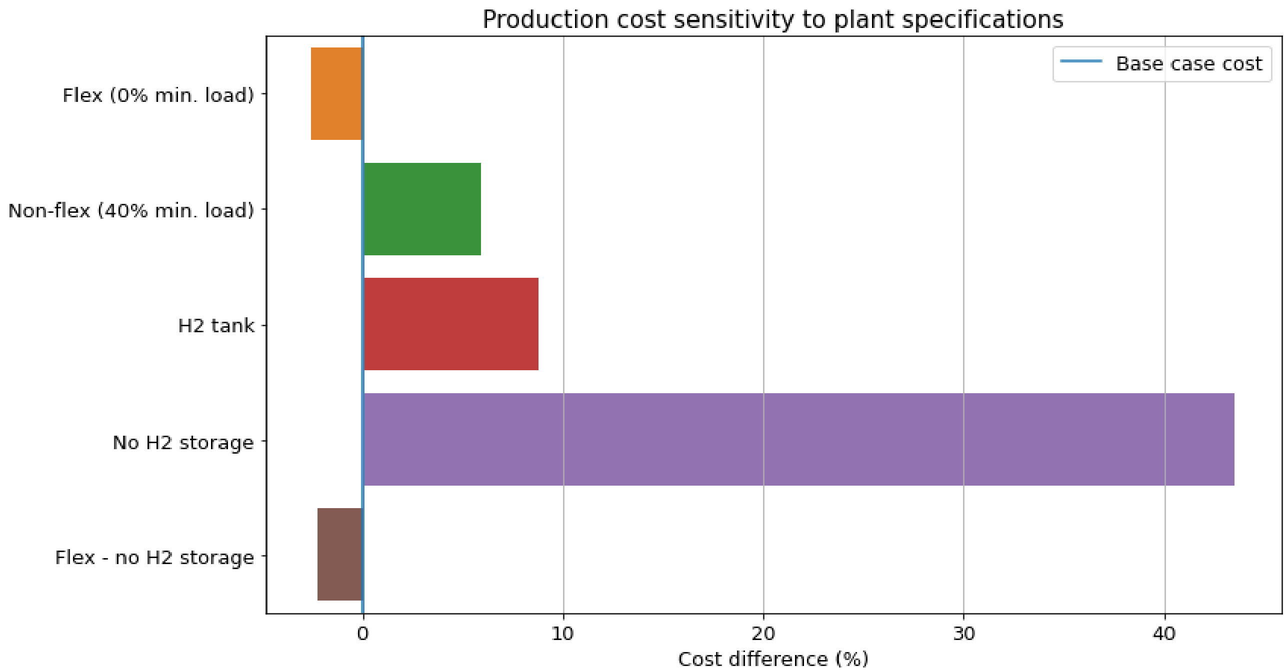

Figure 9: Fuel production cost sensitivities for the different analyzed cases.

Figure 9 show the sensitivity of the fuel production costs under the mentioned assumptions about the ammonia plant's configuration and performance. As the fuel production costs are calculated by dividing the total annualized system costs by the total amount of fuel produced, the sensitivities shown in the graph correspond to both cost values. It was observed that the sensitivity results are generally independent of the choice of electrolyser, but for the current analysis, the AEC technology is chosen.

Observing *Figure* 9, one can see that increasing the minimum operation load of the ammonia plant results in an increase of costs of around 7%. On the other hand, being able to operate with a fully flexible ammonia plant slightly reduces fuel production costs. A fully flexible plant has no significant effects on the costs as it is generally desirable to operate the plant with as many full load hours as possible.

Regarding hydrogen storage, it was observed that having H_2 storage has a critical effect on fuel production costs. Operating the plant without any H_2 storage results in an increase of costs of around 50%. This is mainly due to the need for a much larger wind farm capacity and battery pack to maintain a stable and constant operation of the electrolyser. It is also important to note that using hydrogen tanks instead of buried pipes results in almost a 10% cost increase. This cost difference is primarily due to the lifetime of the hydrogen tanks of just 10 years, whereas the underground hydrogen pipes are expected to last 40-50 years (which makes the economics of the tanks worse than the ones of the buried pipes).

Finally, when combining a fully flexible ammonia plant with no H_2 storage, the value of flexibility increases dramatically. The scenario 'Flex-no H_2 storage', performs almost as well as the 'Flex' scenario (which has the option to invest in storage). This highlights how the cost driver in the scenario 'No H_2 storage' was the inflexibility of the ammonia plant driving up costs in need of a stable hydrogen production.

3.2.1.6 Hydrogen and ammonia production on Bornholm in competition with other locations

This section explores the feasibility of e-fuel production in Bornholm compared to other global locations in a typical/average weather year (2020). Five locations are considered as possible production centres of hydrogen and/or ammonia for this study: Esbjerg (Denmark), Dakhla (Morocco), Arica (Chile), Ceduna (Australia), and Bornholm (Denmark). The locations vary in their renewable energy resources, but the weather year of 2020 is used for all analyses. For instance, it is assumed that Esbjerg and Bornholm (Denmark) are limited to the use of offshore wind power due to socioeconomic reasons. On the other hand, it is considered that the rest of the locations can invest in offshore and onshore wind farms as well as in solar parks. The population densities of the countries are 139, 85, 26, and 3.4 persons/km^2 for DK, MA, CL, and AU respectively [25], which is used as the primary argument for these different investment opportunities (land availability constraint). The wind and solar resources also vary greatly between the places. As an example, the wind resource is very limited in Arica, but its solar resource is significantly better than in Bornholm, reaching a capacity factor of 30.3% compared to 18.3% on Bornholm for 1-axis solar panels.

The investment opportunity in each location also needs to be analysed under varying risk assessments - which influences the effective discount (interest) rate of the investment. So far in this work package, a discount rate of 8% on all investments has been assumed for Bornholm. A study by Nayak-luke and Bañares-Alcántara (2020) [26], investigates the techno-economic viability of green ammonia production in various locations worldwide. The study presents discount rates for all countries in the study. For this comparative analysis of hydrogen and ammonia production with Bornholm's opportunities the following discount rates are used for each country: DK - 7.53%, MA - 9.34%, CL - 8.20%, AU - 7.49%. All other cost metrics are assumed identical and unchanged for the locations.

In summary, the assumptions associated with the five diverse locations differ in terms of available renewable energy sources, power generation profiles, and discount rates for 2030. However, it does not factor in socioeconomic elements like labour costs, existing infrastructure, political stability, regulatory frameworks, transportation logistics... all of which can significantly impact the overall feasibility and attractiveness of each location for such investments.

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In this analysis, the solid-oxide electrolyser (SOEC) technology, along with the heat integration of the different heat flows from the PtX plant, is recognized as an opportunity to enhance process efficiency. Consequently, this comparative analysis employs exclusively the SOEC technology as it also showed the best results for Bornholm in *Section* 3.2.1. The potential sale of by-products (oxygen) in the ammonia production process in Denmark is also taken into account to make its production costs more competitive. For the hydrogen, the comparison is also based on SOEC-based electrolysis based on the same premises.

By running the different studied scenarios for each location in OptiPlant, with a fuel production goal of 2,200 GWh and the weather profiles of 2019, the optimal capacity instalment is determined. It is assumed that the energy densities for H_2 and NH_3 are 33.3 MWh/ton and 5.2MWh/ton, respectively [20]. The optimal sizes for the different units of the ammonia plant are presented in *Table* 10.

Table 10: Optimal sizing for the PtX ammonia plant units (NH_3-SOEC) in various locations for a typical/average weather year (2020). Demand settled at 426kt/year for NH_3 (2200GWh).

	Morocco	**Chile**	**Australia**	**Esbjerg**	**Bornholm**
Wind Farm (WF) [MW]	507.8	0	545.3	904.1	748.7
Solar Farm (SF) [MW]	505.9	1377.8	946.5	*	*
SOEC [MW]	379.0	577.6	453.6	579.1	539.4
Wastewater treat. plant [m3 H_2O/h]	127.9	195.0	153.1	195.5	182.0
NH_3 plant + ASU [t/h]	60.0	56.1	60.0	76.8	74.6
Batteries [MWh]	51.6	1985.4	786.8	198.5	540.1
H_2 storage (buried pipes) [t]	30.3	91.5	131.0	371.5	329.4

[1] The wind farm capacities correspond to an offshore-type wind farm for Esbjerg and Bornholm and to an onshore-type for the rest of the locations.

One can observe in *Table* 10 that the model decides not to invest in wind power in Chile due to the low capacity factor of wind in Arica. Looking at the electrolyser investment decisions, a clear demonstration of the complementary nature of wind and solar power can be noticed. In regions like Morocco and Australia, where both solar and wind resources are reasonably abundant, the required size of the electrolyser installation is notably smaller than in other places. This can be attributed to the more consistent and reliable flow of power these combined resources provide. This effect is especially significant in Morocco, where the need for storage is remarkably lower in comparison to other sites. This is due to the high capacity factors of wind and solar, which translate to sustained and stable power production throughout the year with minimal interruptions.

The obtained fuel production costs of hydrogen and ammonia in the different locations are displayed in *Table* 11. This table also includes the cost of ammonia production considering the revenues from oxygen sales in order to check if this would make Denmark's production more competitive.

Table 11: Fuel production for the PtX ammonia plants (NH_3-SOEC) in various locations for a typical/average weather year (2020). Demand settled at 426kt/year for NH_3 (2200GWh).

	Morocco	**Chile**	**Australia**	**Esbjerg**	**Bornholm**
H_2 fuel production cost [€/MWh]/[€/kg]					
Standard	51.31/1.71	89.65/2.99	94.84/3.16	129.14/4.30	121.63/4.05
NH_3 fuel production cost [€/MWh]/[€/kg]					
Standard	121.71/0.63	130.33/0.67	134.09/0.69	184.22/0.95	176.76/0.91
O2 sale *-DK only-*	*	*	*	170.24/0.88	161.54/0.84

Based on the data in *Table* 11, Morocco emerges as the most economical location for both hydrogen and ammonia production, with hydrogen costing 1.71 €/kg and ammonia at 0.63 €/kg. This cost advantage is primarily due to Morocco's abundant solar and onshore wind resources, and despite its higher discount rate. In comparison, Chile and Australia present similar production costs for ammonia, at 0.67 €/kg and 0.69 €/kg respectively. However, these countries present higher costs for hydrogen production, at 2.99 €/kg and 3.16 €/kg respectively.

On the other hand, Esbjerg and Bornholm are the more expensive locations for both hydrogen and ammonia production. The hydrogen production costs are 4.30 €/kg in Esbjerg and 4.05 €/kg in Bornholm, while ammonia costs stand at 0.88 €/kg and 0.84 €/kg respectively, even considering the oxygen sale on top of the stated standard price.

The SOEC technology was chosen as it can be heat integrated with the excess heat from the ammonia plant and it has better efficiency than AEC. However, using SOEC results in not having excess heat as a byproduct (which could be sold/integrated into the district heating grid). The sale of heat could reduce the ammonia production costs in Denmark significantly, but these costs will probably still be higher than in the other locations. Moreover, the heat demand fluctuates seasonally, and prices can vary widely, complicating the inclusion of this revenue in the feasibility analysis. Therefore, as previously stated, this comparative analysis considered exclusively the SOEC technology as it also showed the best results for Bornholm in *Section* 3.2.1. Focusing solely on the potential sale of oxygen, which is usually priced between 0.027 to 0.15 €/kg [2], it results in a modest reduction of 0.07 €/kg compared to the standard ammonia production cost in the case of Bornholm.

A closer examination of the cost breakdown across various plant units indicated that power generation is the primary cost driver of the PtX plants. The fact that Denmark could only use offshore wind power and the other locations would be able to incorporate onshore and solar energy is the main driver for making the production costs so different (as the cost for the rest of the units is similar for all locations).

Regarding hydrogen production, one of the most critical and costly aspects to consider is its transportation. Although the production costs vary between locations, the subsequent transport to the market significantly influences the final market price. As detailed in *Section* 3.2.1.4, the transportation costs can be estimated based on available data If we assume that this market is located in Germany near Frankfurt am Main, then the distance from Bornholm to the market via direct pipelines is roughly 1000 km, whereas the distance from Dakhla (Morocco) to the market is roughly 3000 km via pipelines. Using the conservative estimate presented in *Section* 3.2.1.4, the levelized costs of transport would be 0.6 €/kg and 1.8 €/kg for Bornholm and Dakhla (Morocco) respectively. This results in final market prices of hydrogen of 4.6 €/kg for Bornholm and 3.5 €/kg for Morocco. As such, the vicinity of Bornholm to the large hydrogen market in Germany does improve the competitiveness of hydrogen produced in Bornholm significantly but does not seem to be able to fully compensate for the difference in renewable power resources in each location under the performed analysis. It however shows that it is possible, albeit difficult, to run competitive PtX plants in an area like Bornholm.

This fact, along with the potential desire for European security of supply, could be reasons to invest in hydrogen production in Bornholm. It should be stressed that this added hydrogen transportation cost is only an approximate calculation. It should be investigated further and is dependent on the pipes actually being invested in. Finally, it also has to be mentioned that this study did not take into account socioeconomic effects or the first-mover advantage, both of which could favour Bornholm.

3.2.1.7 Conclusions from the deterministic analyses (H_2 and NH_3)

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

• **Fuel production costs:** The results show that producing hydrogen has cheaper production costs compared to ammonia (in terms of €/MWh). Two approaches were used when examining the fuel production costs of hydrogen and ammonia: a standard cost analysis and a cost analysis considering by-product sales. For the standard cost analysis, the obtained fuel production prices for the 'typical/average year case' using SOEC in the model are 4.05 €/kg of H_2 and 0.91 €/kg of NH_3. For the cost analysis with by-product sales (heat and oxygen), the fuel production prices for the 'typical/average year case' using SOEC technology are 3.65 €/kg of H_2 and 0.84 €/kg of NH_3.

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 H_2 and between 0.747-0.936 €/kg for NH_3 [27] [28]. The higher hydrogen and ammonia fuel production costs obtained in our study could be due to different factors. The main reason could be our reliance on almost exclusively offshore wind energy, which has a high investment expenditure compared to onshore wind or solar. This results in a reduced capacity factor for the fuel production facility compared to studies involving grid-connected plants or those utilizing a combination of solar and wind power. However, Denmark's strategic location and its role as a potential first-mover in hydrogen and ammonia production present clear advantages, particularly in light of Europe's focus on energy security. These benefits need to be balanced against the higher costs and challenges of the production of these fuels in Bornholm. The feasibility of hydrogen and ammonia PtX plants in Bornholm has opportunities for cost reductions through measures like grid-balancing services and local subsidies.

• **Optimal plant sizing:** For the large-scale PtX plant sizing, the model is driven by a fixed annual fuel demand, which is 66kt/year for H_2 and 426kt/year for NH_3. The capacity of the PtX plant main units (i.e. OWF and electrolyzer) for hydrogen and ammonia production varies depending on the electrolysis process. AEC-PtX plants generally require larger capacities overall, whereas SOEC-PtX plants need smaller ones due to better efficiency. The capacities for MIX-PtX plants typically fall between those of AEC and SOEC.

The capacities of wastewater treatment plants reflect the water demands for electrolysis, remaining almost constant across scenarios for the same fuel production in a given weather year.

The study has revealed that only the production of ammonia demands investment in storage solutions such as batteries and hydrogen pipes. This is due to the increased complexity of the PtX system and the need to optimize the operation of the ammonia production plant (the ammonia synthesis plant minimum load is set at 20%). Batteries and hydrogen storage are essential in balancing the intermittent nature of wind energy. Their required capacities vary significantly across different years, highlighting a greater demand for energy storage in less windy years.

- **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. However, as alkaline electrolysis cells (AEC) and SOEC technologies are subjects of intensive ongoing research, an updated evaluation of these technologies would be essential before making any investment decisions. This is because the competitiveness of each technology is highly sensitive to breakthroughs and the establishment of stable supply and demand in the electrolyzer market.

- **Major cost components of the H_2 and NH_3 plants:** Considering the typical weather year as a basis, the offshore wind farm (OWF) represents approximately 63% of the total expenses in scenarios dedicated to hydrogen production and about half of the costs in ammonia production scenarios. The electrolysis units account for roughly 36% of the costs in hydrogen-focused scenarios and 27% in those centred on ammonia. In scenarios where ammonia production is involved, the NH_3 production plant comprises around 14% of the overall expenses. This financial analysis highlights the significant impact that both the OWF and electrolysis processes have on the plant's economics, marking them as critical targets for cost-reduction potential.

- **Water resources availability:** 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 system robustness. In the months/periods in which one of the plants alone could not supply the totality of the water needed, a combination of wastewater from different plants could be used. The available wastewater in Bornholm can supply the water demand from the large-scale PtX plants by far.

- **Excess heat production and DH integration:** An assessment of the excess heat from hydrogen and ammonia PtX plants has been performed, showing that all the large-scale PtX scenarios (except SOEC-based) could generate similar monthly heat amounts than the combination of the current 7 heat-production facilities. Given that the precise temperatures of the excess heat from the PtX plants are not accurately determined, and the grids are not connected, further investigation is necessary to understand the associated cost factors for adapting this heat to the district heating system's requirements.

- **Potential for hydrogen 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. The cost of transporting hydrogen from Bornholm to Germany is estimated at approximately 0.60 €/kg_{H_2}/1000km for the initial 140 km via a medium-sized, new hydrogen pipeline. Beyond this distance, it is expected that the hydrogen will be transported more economically by retrofitting existing network in Germany and Europe. With a pipeline extending 1000 km from Bornholm, all of Germany could be covered, indicating that the maximum likely additional transport cost would be around 0.6 €/kg_{H_2}. This translates to an increase of about 15% for hydrogen produced in Bornholm. The cost of transporting hydrogen through a hydrogen pipeline can prove beneficial for the competitiveness of producing hydrogen in Bornholm, as the production is strategically better located compared to e.g. Morocco.

- **Sensitivity analyses:** The sensitivity analyses focused on the hydrogen storage and the flexibility of the ammonia plant, showing significant insights. On one hand, in terms of hydrogen storage, the analysis revealed that using hydrogen tanks led to a 10% increase in fuel costs (compared to the buried pipes base case), mainly due to their shorter lifetime. The absence of any hydrogen storage option prompted the need for a larger wind farm and battery capacities, increasing the fuel production costs by about 50% from the base case.

On the other hand, regarding the ammonia plant flexibility, it was found that increasing the minimum load to 40% (2020 value) escalated costs by approximately 7%. Conversely, having a fully flexible plant only reduced total costs by 3%. Finally, in the scenario with a fully flexible plant and no hydrogen storage, the total costs were reduced also around 3%, showcasing that the an important cost driver for the scenario with no H_2 storage is the inflexibility of the ammonia plant.

• **Hydrogen and ammonia production competition with other locations:** The study compared the hydrogen and ammonia production costs of SOEC-PtX plants located in different places around the globe based on their available renewable energy sources, power generation profiles, and discount rates for 2030. No socioeconomic factors such as labour costs, infrastructure, political stability, or regulatory frameworks were taken into account in the comparison.

The study identified Morocco as the most cost-effective location, with hydrogen and ammonia production costs at 1.71 €/kg and 0.63 €/kg respectively. This cost advantage is attributed to Morocco's rich solar and wind resources. Conversely, Bornholm shows higher production costs, at 4.05 €/kg for hydrogen and 0.84 €/kg for ammonia (Bornholm's costs including the sale of oxygen for NH_3-SOEC). These higher costs are primarily because in the model the Danish locations were limited to using only offshore wind energy, while the other locations used cheaper technologies like solar or onshore wind. The power generation technologies are the main cost driver in PtX plants. The sale of by-products like heat or oxygen could reduce costs in Danish locations, but their production costs still remain higher compared to Morocco, Chile, or Australia. However, the proximity of Denmark to key markets like Germany could increase the price competitiveness of Bornholm or Esbjerg when producing hydrogen. A desire for a European security of supply could also factor into the decision to support PtX investments in an area like Bornholm, e.g. through subsidies. Finally, using different PtX plant configurations (such as grid-connected) in Denmark has shown potential ammonia production costs similar to those in Morocco **see Section 3.2.3 on grid-connected ammonia plant.*

3.2.2 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.

3.2.2.1 Optimal power-to-X plant sizing and cost analysis 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* 12. For comparison, the sizing data from the deterministic analyses, previously presented, is also included in *Table* 12 on the following page.

Table 12: Optimal sizing for the large Power-to-X plant units for different scenarios under the stochastic analysis (H_2 and NH_3) -deterministic results also included in italics for comparison-. Demand settled at 66kt/year for H_2 and 426kt/year for NH_3 with economic penalties for over- and underproduction.

	H_2-AEC	H_2-SOEC	H_2-MIX	NH_3-AEC	NH_3-SOEC	NH_3-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 [t H_2/h]/[MW_i]						
Stochastic 2016-2021	13.4/667.9	13.3/578.2	13.4/645.4	15.7/782.7	15.3/661.6	15.5/750.6
Deterministic: typical year (2020)	*14.3/715.6*	*14.3/620.8*	*14.3/691.9*	*16.4/818.2*	*16.2/700.3*	*16.4/788.7*
Deterministic: best case year (2017)	*13.8/688.8*	*13.8/597.5*	*13.8/666.0*	*15.9/796.3*	*15.8/683.9*	*15.9/767.5*
Deterministic: worst case year (2018)	*16.0/799.5*	*16.0/692.1*	*16.1/772.8*	*18.3/911.3*	*17.9/775.4*	*18.2/874.9*
Wastewater treat. plant [m^3 H_2O/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*
NH_3 prod. plant (+ ASU) [t NH_3/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*
H_2 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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The sizing results for the Power-to-X plant units under the stochastic analysis, as outlined in *Table* 12, illustrate the need for adaptable plant capacities to accommodate varying scenarios for hydrogen (H_2) and ammonia (NH_3) production.

Under the stochastic approach, which uses data from 2016 to 2021, there is a noticeable adjustment in the required capacities of various units compared to the deterministic analysis. For example, in the case of the offshore wind farm, the installed capacity required in the stochastic scenario is generally lower than in the deterministic cases. This pattern is observed across different electrolyzer technologies, with the stochastic scenario indicating a shift towards more efficient and conservative utilization of resources.

Regarding the wastewater treatment plant, the stochastic scenario demands are quite consistent with the deterministic analysis, reflecting the less variable nature of water requirements for electrolysis.

In terms of energy storage units, such as batteries and H_2 storage, the stochastic analysis highlights the importance of flexibility and scalability in energy storage solutions to accommodate the intermittent nature of wind energy and the fluctuating demands of the plant. This can be observed with higher investments in these storage technologies in the stochastic analysis compared to all the deterministic study cases.

For this particular analysis, the fuel production cost for each of the selected relevant scenarios was also examined. It is assumed that the energy densities for H_2 and NH_3 are 33.3 MWh/ton and 5.2MWh/ton, respectively [20]. *Table* 13 provides a numerical summary of the fuel production cost for all the scenarios under the stochastic sizing approach.

Table 13: Fuel production cost of different scenarios under the stochastic analysis (H_2 and NH_3). Demand settled at 66kt/year for H_2 and 426kt/year for NH_3 with economic penalties for over- and underproduction.

	H_2-AEC	**H_2-SOEC**	**H_2-MIX**	**NH_3-AEC**	**NH_3-SOEC**	**NH_3-MIX**
Fuel production cost [€/MWh]/[€/kg]						
Stochastic 2016-2021	138.78/4.62	123.01/4.10	134.84/4.49	203.28/1.05	180.84/0.93	203.11/1.05

When comparing fuel production costs from the stochastic analysis (*Table* 13) with those from the deterministic sizing approach (*Table* 7), it is clear that the stochastic results closely align with those corresponding to a typical/average weather year in the deterministic analysis. This observation is supported by additional internal studies. Notably, even though the plant sizing and annualized system costs differ between the two methods, the variation in the amount of produced fuel leads to comparable production costs.

3.2.2.2 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 centres 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* 14.

Table 14: Breakdown of land usage for the large Power-to-X plant by unit for various scenarios under the stochastic analysis (H_2 and NH_3). Demand settled at 66kt/year for H_2 and 426kt/year for NH_3 with economic penalties for over- and underproduction.

	H_2-AEC	H_2-SOEC	H_2-MIX	NH_3-AEC*	NH_3-SOEC*	NH_3-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
NH_3 prod. plant (+ASU) [Ha]	0.0	0.0	0.0	1.0	1.0	1.0
NH_3 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.

Figure 10 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* 14. 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.

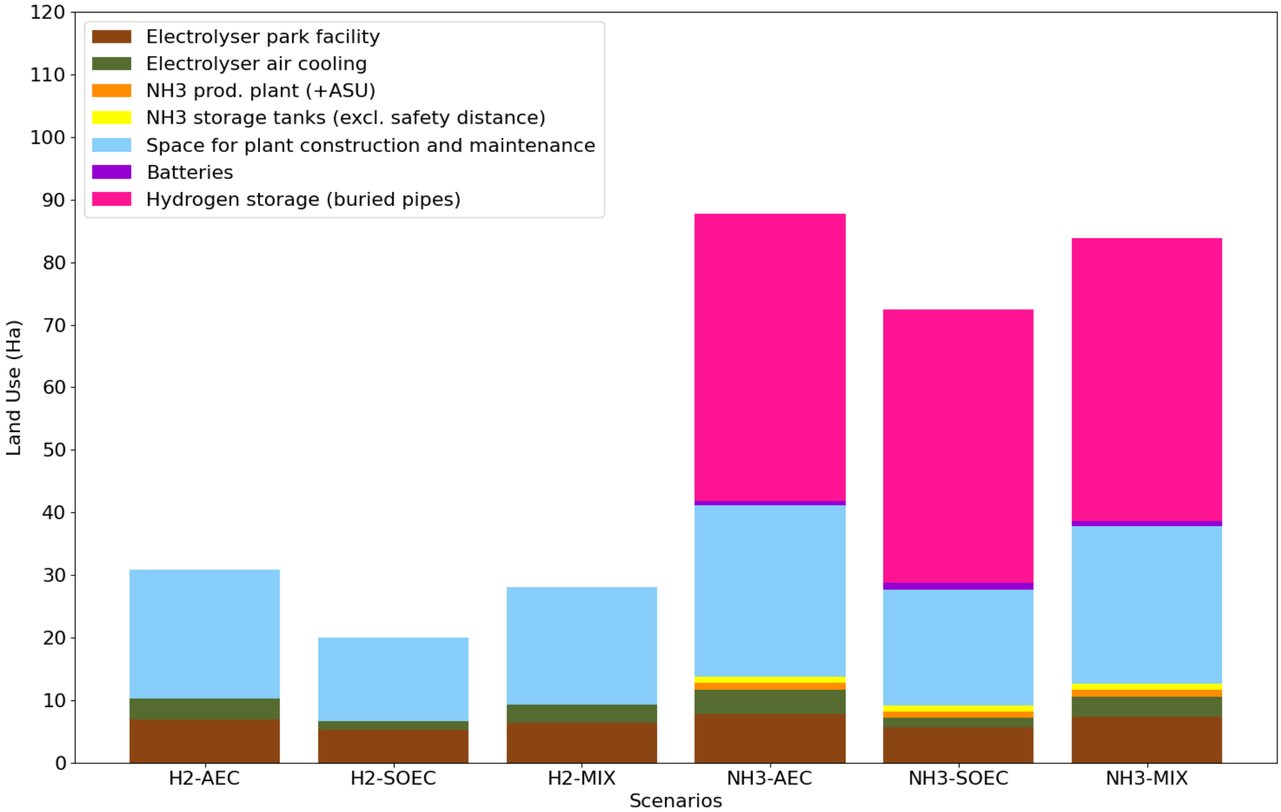

Figure 10: Breakdown of the total land use of the different PtX plant units. The areas correspond to the space occupied by the optimal unit capacities sized using the model's stochastic approach.

Analyzing the results from *Table* 14 and *Figure* 10, which outlines the land use for the PtX plant units under stochastic analysis, several key insights emerge about space requirements for hydrogen and ammonia production.

The electrolyzer park, excluding the space for construction and maintenance, requires the most land among the different units. Specifically for the SOEC technology, the electrolyzer park occupies 5.3 Ha for H_2 and 5.7 Ha for NH_3.

Comparatively, the total land use for ammonia plants (NH_3-SOEC) without considering buried pipes is higher than that for hydrogen plants (H_2-SOEC), at 28.7 Ha vs. 20.0 Ha respectively. This represents a significant increase, approximately 43.5% more land for ammonia plants compared to hydrogen plants in the SOEC scenario. For reference a transformer sub-station usually occupies 107 Ha.

In the case of ammonia plants, an additional consideration is the significant land required for hydrogen storage, primarily for buried pipes, amounting to 43.8 Ha for the NH_3-SOEC scenario. This substantial space could be optimized by constructing facilities on top of the buried pipes, as long as this aligns with safety and operational protocols. Furthermore, it has to be considered that ammonia storage requires a safety distance of approximately 1 km from populated areas, considerably increasing the actual land usage. This requirement underscores the necessity for careful site selection, taking into account both safety and space efficiency.

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3.2.2.3 Conclusions from the stochastic analysis (H_2 and NH_3)

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:

• **Optimal plant sizing and cost analysis under weather uncertainties:**
The results from the stochastic analysis, compared to the deterministic scenarios, show that the production plant sizing is similar to the best-case weather year, with most units' capacity being 5-10% smaller than in the deterministic typical year. In contrast, storage units in the stochastic analysis are significantly larger to accommodate uncertainties.

However, key cost metrics like fuel production costs are almost equal to the ones with the deterministic typical/average weather year. This suggests that while employing both deterministic and stochastic analyses can enrich the understanding of the PtX plant's characteristics, utilizing a deterministic approach with an average weather year can effectively capture the necessary economic aspects for feasibility studies.

• **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 ammonia production is substantially higher than that for hydrogen production (above 43.5% more land required). The demand for storage units, especially buried pipes, contributes to an increased land footprint for ammonia plants. However, this could be potentially mitigated by constructing additional facilities above these storage areas. Additionally, the requirement of maintaining a safety distance of approximately 1 km radius around ammonia plants significantly adds to their overall land usage. This factor is essential in site selection for ammonia plants, emphasizing the balance between operational safety and efficient land utilization.

3.2.3 Extra study: Grid-connected large-scale ammonia plant

This section explores an alternative scenario for the large-scale ammonia plant. In contrast to the PtX plant configuration used in the rest of the investigation (Behind-the-Meter), in this case, all the plant components can be also powered by the grid. This configuration is also named semi-islanded. *Figure* 11 shown on the next page presents the power supply and plant configuration for the studied semi-islanded large-scale ammonia plant.

The purpose of this study is to compare (through some sensitivity analysis) the fuel production cost of the semi-islanded configuration with the ones of the behind-the-meter (BTM) configuration. Moreover, this study aims to enable the discussion of the effect on plant capacity utilisation, certification of green fuels, and power balancing in the grid. The BTM base case used for comparison is to the deterministic scenario NH_3-AEC for the typical/average year (2020).

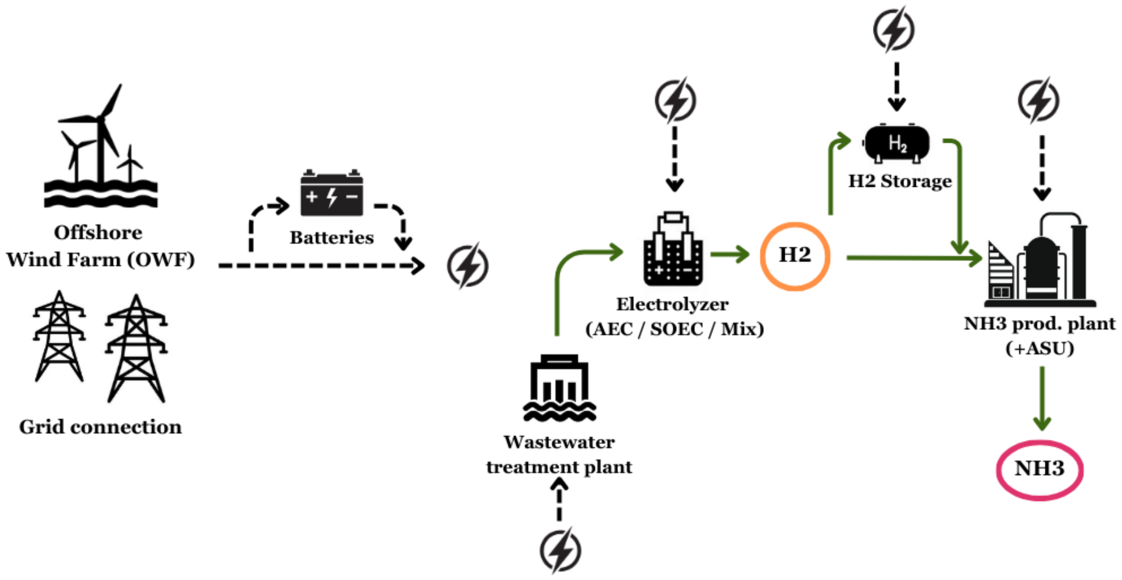

Figure 11: Scheme showing a simplified semi-islanded power supply configuration of the PtX ammonia plant.

DK2 electricity spot prices for 2030 have been simulated using Balmorel to run two different scenarios -low gas price and high gas price-. These two scenarios result in a likely interval for the grid electricity price in 2030. The spot price distributions for each yearly profile can be seen in *Figure* 27 displayed in *Section* 7.5 of the *Appendix*. From the figure, it can be observed that the average spot price for each of the studied profiles is around 0.25 DKK/kWh. The cost of procuring electricity for PtX production is assumed to be equal to this spot price, hence primarily disregarding transmission network tariffs as the operation is assumed to be connected to the grid at the transmission level, and thus be exempt from electricity taxes, VAT, and distribution grid tariffs. A more detailed analysis of the impact of tariff costs on the cost of grid-connected PtX operation should be considered for future studies.

Figure 12 shows the sensitivity of the fuel production costs under the mentioned assumptions about the ammonia plant's configuration and performance. As the fuel production costs are calculated by dividing the total annualized system cost by the total amount of fuel produced, the sensitivities shown in the graph are the same for both economic indicators. It was observed that the sensitivity results are generally independent of the choice of electrolyser, but for the current analysis, the AEC technology is chosen.

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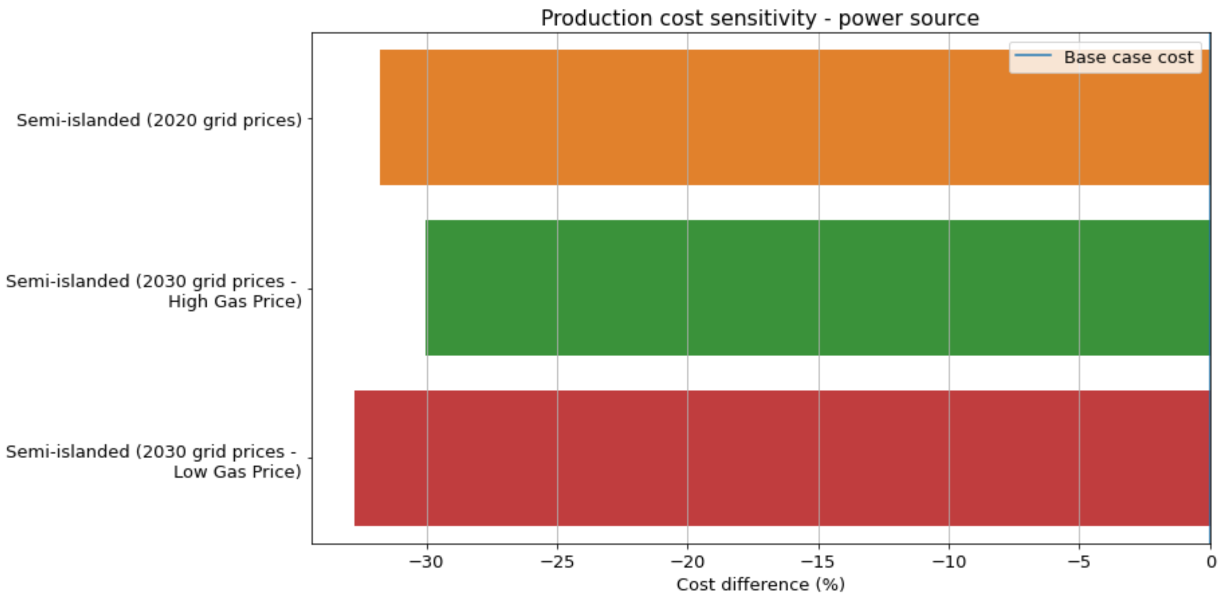

Figure 12: Fuel production cost sensitivities to the different scenarios in the semi-islanded ammonia plant configuration.

As can be seen in *Figure* 12 the ammonia production cost is significantly decreased in the semi-islanded configuration compared to the behind-the-meter case (between -30% and -35%). This is in part due to the fact that the average cost of supplied energy falls from 58.2 €/MWh to 49.2 €/MWh. The primary component of the cost savings, however, comes from the reduction in the size of the electrolyser and the ammonia plant: as the grid enables these units to operate at nominal load during all operating hours of the year, the capacity instalment needs are significantly reduced, resulting in a -43% electrolyser cost reduction and the removal of the need for any intermediary storage.

Referencing back to *Section* 3.2.1.6 on the comparison of fuel production costs in various locations, and specifically the costs shown in *Table* 11, it is of interest to see what this 30% reduction of ammonia production price means for the competitiveness of the ammonia production on Bornholm. *Table* 11 shows a levelized cost of ammonia of 161.54 €/MWh (0.84 €/kg) when produced on Bornholm and considering by-product sale revenues, and a cost of 121.71 €/MWh (0.63 €/kg) when produced in Morocco. A 25% reduction in ammonia production costs on Bornholm, factoring in the revenue from by-product sales, and a 30% reduction without considering these sales, both lead to a cost of 121.71 €/MWh for ammonia. This cost is comparable to that of the ammonia produced in Morocco. Under the present assumptions, this indicates that the grid-connected PtX plant in Bornholm is competitively priced, and slightly better when selling by-products, in comparison to the Moroccan plant.

It can also be observed that having different gas prices results in a difference of ±5% between the different 2030 scenarios. On top of that, it can also be seen that the differences between the 2020 and 2030 scenarios are not significant (±2%). Based on this, it is assumed that the price development of grid-supplied electricity likely will not change the main takeaways of this analysis, albeit the projection of electricity prices was based on Bornholm having the same prices as the rest of East Denmark, while it may have its own price zone in the future when the energy island is built.

The cost reduction of the semi-islanded plant configuration comes at the price of not being able to ensure that the ammonia produced is green, as that will depend on the carbon emissions related to the power provided by the grid. Evaluating the 'green' characteristics of a fuel produced using grid electricity is a complex task. It requires considering various factors, such as the source of the electricity (additionality), as well as the temporal and geographical correlation of electricity within the grid [29], to confirm that the e-fuel is genuinely renewable.

This could realistically mean that a grid-connected PtX plant needs to operate more or less as if it was installed behind-the-meter, since it has to follow a power-purchasing agreement with new renewable electricity generation capacity in the geographical vicinity of the PtX plant. The following paragraphs on the carbon footprint of this hypothesized grid-connected PtX plant aim to show the reason why this implementation might prove challenging.

The yearly average CO_2 emissions related to power from the grid in Bornholm was 0.188 $kgCO_2e/kWh$ for the year 2020 (the grid electricity emissions for 2030 were not simulated in this study). This results in average emissions of 1.82 $kgCO_2e/kgNH_3$. The Green Hydrogen Organisation sets the emissions limit for green hydrogen at 0.3 $kgCO_2e/kgNH_3$ [30], meaning that the semi-islanded NH_3 plant setup does not ensure the production of green ammonia. The greenest power available during the year 2020 in Bornholm's power grid had a carbon footprint of 0.039 $kgCO_2e/kWh$, which results in an ammonia carbon footprint of 0.367 $kgCO_2e/kgNH_3$, meaning that the energy mix on Bornholm is currently never green enough to produce green ammonia in a grid-connected setup. For reference, the calculated carbon footprint of ammonia produced when powered solely by an offshore wind farm is 0.13 $kgCO_2e/kgNH_3$. This includes emissions related to the construction and operation of the ammonia plant, the electrolyser, storage, and the wind farm. The Green Hydrogen Organisation's threshold for green ammonia might be contested as too limiting for the certification of green fuels. CertifHy, an EU-requested Guarantee-of-Origin (GO) provider for green fuels, enables the certification of a green fuel if the carbon footprint is more than 60% lower than the benchmark fossil fuel-based process. The benchmark GHG emissions for ammonia produced in the EU is 1.57 $kgCO_2e/kgNH_3$ [31]. Using this certification, the grid-powered ammonia production might be able to obtain a green certificate powered by the grid during the hours with less fossil-fuel-based electricity in the energy mix as it needs to have emissions lower than 0.63 $kgCO_2e/kgNH_3$. This is only achievable with power supplied from Bornholm's grid for roughly 15% of the hours of the year when taking basis in the emissions related to grid electricity in the year 2020. It should be noted that the grid electricity might be greener in 2030 as more renewable energy generation capacities are connected to the grid, which could improve the outlook of a grid-connected plant.

Another critical aspect of using the power grid for powering the ammonia plant is the availability of sufficient grid capacity on Bornholm. In the model, no limitations on the grid capacity are implemented, allowing the plant to operate at maximum full load hours. In the ammonia plant with an AEC, the peak power needed from the grid is 487 MW. In Bornholm, the only power generation technology with a large enough capacity to supply this load is the prospective offshore wind farm (GW scale). This implies that, without considering energy imports, the semi-islanded PtX plant would need to operate with the same level of flexibility as the behind-the-meter setup. The possibility of importing power from either Germany or Zealand might change this situation. Currently, the only cable connecting Bornholm to the rest of the European power grid, is a 60 MW cable running to Sweden [32]. However, there are some plans to install a 1.2 GW cable to Zealand and a 2 GW cable to Germany [33]. These connections could then provide the capacity needed to enable the semi-islanded ammonia plant to operate without the need for high flexibility.

3.2.3.1 Conclusions from the study on grid-connected NH_3 plants

This extra study focused on studying an alternative plant configuration for the large-scale ammonia plant. Unlike the Behind-the-Meter (BTM) configuration primarily explored in the main investigation, here, the plant components can also be powered by the grid. The main takeaways from this extra-analysis are displayed in the following page.

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- **Comparison of plant configurations:** This study compares the semi-islanded and behind-the-meter (BTM) configurations for fuel production costs. The semi-islanded setup, using grid electricity, showed a substantial fuel production cost reduction (between -30% and -35%) compared to the Behind-The-Meter scenarios. This is partly due to the lower average energy supply cost and the decreased size of the electrolyser and ammonia plant, eliminating the need for intermediary storage.

- **Electricity price projections and impact:** DK2 electricity spot prices for 2030, under varying gas price scenarios, indicate a likely interval for grid electricity price. The cost of procuring electricity for PtX production, equating to the spot price, doesn't significantly affect the primary findings of the analysis, as differences between the 2020 and 2030 scenarios are minor ($\pm 2\%$), and the primary savings from a BTM plant to a grid-connected plant stems from the reduced capital costs as the necessary size of the plant units are significantly smaller.

- **Competitiveness of Bornholm's ammonia production:** A 30% reduction in ammonia production costs in Bornholm in the semi-islanded configuration, aligns its production costs (121.71 €/MWh) with those of Morocco. This positions the grid-connected PtX plant in Bornholm as price-competitive to the BTM scenarios in Morocco, Chile or Australia under the assumptions taken for this study.

- **Green certification of ammonia:** The semi-islanded configuration complicates the certification of ammonia as 'green' due to reliance on grid power and its associated CO_2 emissions. The current energy mix in Bornholm's grid doesn't consistently meet the green criteria for ammonia production from different organizations, but the energy mix emissions in 2030 are expected to drop, making it possible to produce green ammonia with grid electricity. However, challenges for a grid-connected PtX-plant persist as certification of renewable fuels requires that the PtX-plant is provably powered by dedicated renewable power sources [29].

- **Grid capacity and flexibility:** The feasibility of the semi-islanded ammonia plant depends on the availability of sufficient grid capacity. Given the current sizing of Bornholm's electricity grid, the plant requires a similar level of flexibility as the BTM setup, as the load of the 2,200 GWh NH_3/yr plant is a main consumer in the grid, and there is no power production capacity available to ensure a constant delivery of power to the plant. Future energy infrastructure developments, like increased grid connections to mainland Europe, could change that situation.

4 Phase 2: Small-scale e-biofuel production

4.1 Technical and economic considerations for Power-to-X and e-biofuel production at Bornholm

The second phase of WP2 was centred around designing relevant scenarios to evaluate the feasibility of small-scale methanol production in Bornholm using the biogenic carbon resources of the island. The main goal was to determine whether these carbon resources could satisfy a significant share of the local fuel/energy demand and help the decarbonization of the island (and if this was feasible from a techno-economical point of view). This section presents a detailed description of the input data and assumptions considered in this second investigation.

4.1.1 Input data

The input data for all of the studied scenarios in Phase 2 of the study 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 and fuel production plants) is detailed in *Table* 15 and *Table* 16 found below. More information on the different plant units can also be found in the rest of the tables in *Section* 7.1 of the *Appendix*.

Table 15: Input technological assumptions for 2030 used in the model for the small-scale PtX plant study

Type of units	Input/Output -	Capacity -	Fuel production rate kg output/kg input	Load min % of max capacity	Electrical consumption kWh_{el}/output	Excess heat > 80^o kWh_{th}/output
MeOH plant - CO2	H_2/MeOH CO_2/MeOH	kg_{MeOH}/h	5.26[1] 0.73[1]	20[2]	0.316[3]	0.68[3]
MeOH plant - Biogas	H_2/MeOH Biogas/MeOH	kg_{MeOH}/h	22.0[1] 1.17[1]	20[2]	1.31[4]	1.23[4]
MeOH plant - Biomass	H_2/MeOH Biomass/MeOH	kg_{MeOH}/h	15.7[1] 0.86[7]	20[2]	0.64[7]	0.43[7]
Wastewater plant	-/H_2O	kg_{H_2O}/h	0	0	0.0025[6]	0
Electrolyser Park AEC	H_2O/H_2	kg_{H_2}/h	0.1[7]	0	49.8[8]	5.68[8]
E.P. SOEC heat integrated	H_2O/H_2	kg_{H_2}/h	0.1[7]	0	37.9[9]	0
E.P. SOEC alone	H_2O/H_2	kg_{H_2}/h	0.1[7]	0	43.2[8]	0
H_2 storage tank	H_{2in}/H_{2out}	kg_{H_2}	0	3[10]	0	0
H_2 storage buried pipes	H_{2in}/H_{2out}	kg_{H_2}	0	9[11]	0	0
Battery Park	kWh_{in}/kWh_{out}	kWh	0	0[12]	0	0
DAC plant	Air/CO_2	kg_{CO_2}/h	-	0	1.7[13]	0
Pyrolysis plant[14]	Digestate/Gas Digestate/Char Digestate/Oil	$kg_{digestate}/h$	0.15 0.18 0.09	0	0.14[15]	0.28[15]

[1] Based on [6] - stoiciometrically defined with 100% conversion of carbon and gases.
[2] Based on [34].
[3] Based on [35].
[4] Based on [36].
[5] Based on [37].
[6] Based on [7].
[7] Consumption of non-purified water assuming a purification efficieny of 80% based on [7].
Conversion of purified water to hydrogen is stoichiometric (9 kg of water consumed per kg of hydrogen).
[8] Based on [6].
[9] From [38] (assuming that heat integration performances will be similar as of 2020).
[10] Based on [8].
[11] Based on [9] assuming same values as of 2020.
[12] Based on communication with industrial partners.
[13] Estimate based on [39] and [6].
[14] Based on [40] - technology catalogue bases its assumptions primarily on Stiesdal's SkyClean project.
[15] The unit is kWh/input.

Table 16: Input economical assumptions for 2030 used in the model for the small-scale PtX plant study

Type of units	Capacity -	Investment €/Capacity	Fixed cost €/Capacity/y	Variable cost €/Output	Lifetime Years
MeOH plant - CO2	kg_{MeOH}/h	23670[1]	947[2]	0	20[3]
MeOH plant - Biogas	kg_{MeOH}/h	30770[4]	1231[2]	0	20[3]
MeOH plant - Biomass	kg_{MeOH}/h	40000[5]	1600[2]	0	20[3]
Waste water plant	kg_{H_2O}/h	107.6[6]	3.2[7]	0	15[8]
Electrolyser Park AEC	kg_{H_2}/h	39840[9]	3984[10]	0	25[3]
E.P. SOEC heat integrated	kg_{H_2}/h	39584[11]	3384.4[12]	0	25[3]
E.P. SOEC alone	kg_{H_2}/h	39584[11]	3384.4[12]	0	25[3]
H_2 storage tank	kg_{H_2}	800[13]	24[14]	0	10[15]
H_2 storage buried pipes	kg_{H_2}	250[16]	7.5[14]	0	50[17]
OFF_SP379-HH100	kW	1998[18]	37.6[18]	0.0028[18]	30[18]
OFF_SP379-HH150	kW	2297[18]	37.6[18]	0.0028[18]	30[18]
OFF_SP450-HH100	kW	1801[18]	37.6[18]	0.0028[18]	30[18]
OFF_SP450-HH150	kW	2053[18]	37.6[18]	0.0028[18]	30[18]
1-axis tracking Solar Park	kWp	458.8[18]	9.28[18]	0[18]	40[18]
Battery Park	kWh	180[19]	2.7[20]	0	25[20]
DAC plant	kg_{CO_2}/h	6000[21]	300[21]	0	20[22]
Pyrolysis plant	$kg_{digestate}/h$	3028[23] OR 3788 from tech. cat.	401[24] OR 327 from tech. cat.	0	25

[1] For a small-scale 6.7 t_{MeOH}/h plant capacity based on [35], [41], [42], validated by [6].
Capital cost scaled by power law - scaling factor ~0.7. [6] refers to a CAPEX of 17532€ per capacity installed
for medium-scale plant of 13.3 t_{MeOH}/h, and 8328€/Capacity for large-scale plant of 133 t_{MeOH}/h.
[2] 4% of capital investment based on [6].
[3] Based on [43].
[4] 130% of capital investment compared to MeOH plant - CO_2. Estimated additional cost of reformer
Based on [44], and assuming similar costs for electrical vs conventional reformers. Both validated by stakeholders.
[5] 130% of capital investment compared to MeOH plant - Biogas. Estimated additional cost of gasifier and gas cleaning units.
Based on [37], validated by stakeholders.
[6] Using the 2025 benchmark value based on [7].
[7] 3% Capex based on [7].
[8] From [7].
[9] From [6]. Corresponds to a CAPEX of 800€/kW_e.
[10] Using 10% Capex based on [6].
[11] Based on [12] and talks with industry partners.
Corresponds to a CAPEX of 1157€/kW_e for a heat integrated SOEC and 916€/kW_e for non-heat integrated SOEC.
[12] 8.55% Capex based on [12].
[13] Based on [10] (includes compressors).
[14] 3% Capex based on [10].
[15] For high-pressure tanks, life span is around 10 years, depending on the frequency of filling/empyting. Based on [13].
[16] Based on [10] for a working pressure around 100 bars.
[17] Based on [14].
[18] From [15].
[19] From [10] assuming low lithium price.
[20] 1.5% Capex based on [10].
[21] Estimates based on [6].
[22] Based on [45].
[23] Based on [3] with plant of 20 MW input biomass.
[24] 13.25% of capital investment based on [3].

4.1.2 Framework and parameters for scenario development

The choice of the relevant studied scenarios resulted from thorough discussions with all the project's stakeholders. These scenarios took into consideration a broad range of parameters including: time horizon, plant scale, plant configuration, power supply technologies, renewable energy profiles, electrolyzer technology, available biogenic carbon resources, fuel synthesis routes, demand profile type, and sizing method. *Table* 17 shows the different aspects considered in the scenarios studied in the phase 2 investigation (small-scale e-biofuel production).

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Table 17: Parameters considered when designing the scenarios explored in the study of Phase 2 of WP2 (Small-scale e-biofuel production)

Parameter	Small-scale PtX plant (Phase 2)
Time horizon	Techno-economic projections for 2030
Plant scale	Small-scale (10-250MW)
Plant configuration	Off-grid (behind-the-meter)
Power supply technologies	Offshore wind and solar energy
Renewable energy profiles	Weather data from 2016 to 2021
Electrolyzer technologies	AEC and SOEC
Available biogenic carbon resources	CO_2 (point-source and DAC), biogas and biomass
Fuel produced and synthesis routes	Methanol (4 different routes)
Demand profile type	Yearly demand
Sizing method	Deterministic

A more detailed description of the assumptions and implications of the accounted parameters in this study is presented in the following paragraphs:

Time horizon

The year 2030 was selected as the time frame for both WP2 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% -from 1990 levels- 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 small-scale (MW order of magnitude) PtX plant focused more on understanding Bornholm's renewable energy potential towards local self-sufficiency and efficient utilization of the carbon sources of the island.

Plant configuration

In terms of plant configuration, it is assumed that the studied scenarios operate 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. While it is assumed that the Power-to-X plant owner also owns a share of the renewable power assets and can use them freely, the investment and operational costs associated with these assets are the responsibility of the PtX plant owner. This 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 due to the broad mix of energy sources in the grid. *Figure* 13 presents the power supply and plant configuration for the small-scale PtX plant investigation.

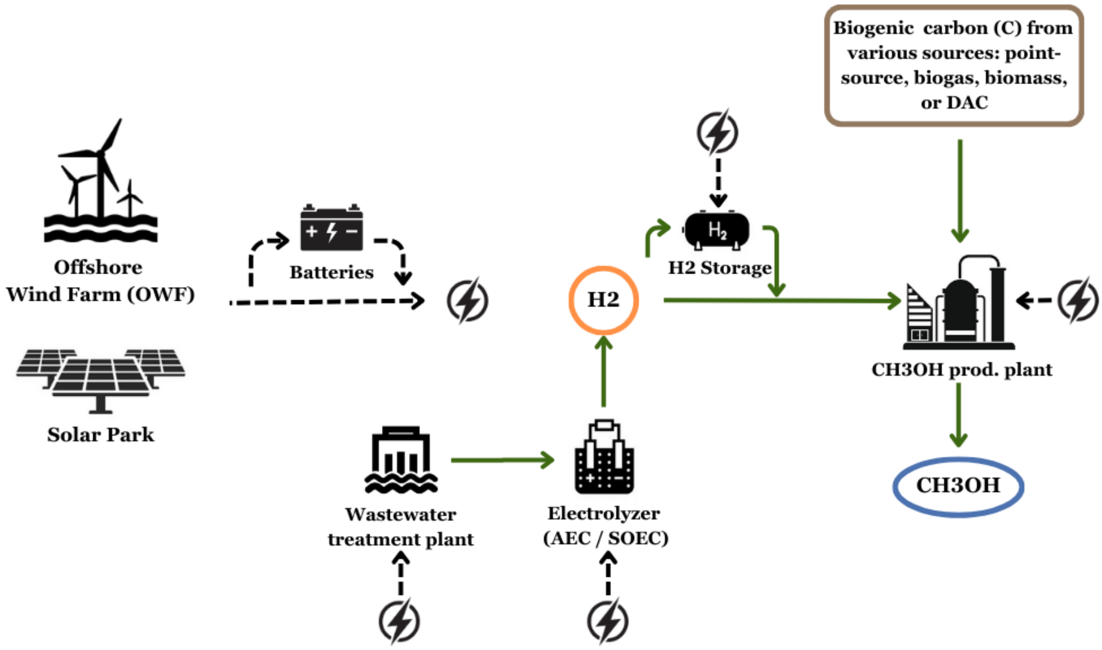

Figure 13: Scheme showing a simplified behind-the-meter (BTM) power supply configuration of the Power-to-X plant considered in the model for the large-scale study [5].

Power supply technologies

The simulated scenarios for the small-scale study, focused on methanol production, considered offshore wind turbines as well as solar photovoltaic (PV) parks as the power supply technology. WP1 has identified that between 30-40 MWp of solar parks will be available for PtX purposes on Bornholm. The limit on the allocation of solar power installations for the pathways studied in phase 2 is 40 MWp. For the offshore wind farm (OWF), the capacity limit was set at 800 MW. This figure is based on considering the maximum potential for overplanting dedicated to PtX in the projected offshore wind farm to be constructed around Bornholm.

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 distinct sources. Wind profiles were sourced using the CorRes tool [16], while solar data was acquired from renewables.ninja [17],[18]. Individual year's data was used for the deterministic studies.

Electrolyzer technologies

In the modelling of the small-scale Power-to-X plant, the primary focus was on utilizing Solid Oxide Electrolyzer Cells (SOEC) technology due to its potential for heat integration with the methanol synthesis process, resulting in a higher process efficiency.

The use of alkaline electrolyzer cells (AEC) in the PtX plant was also considered in a supplementary aspect of the study. The inclusion of AEC was done to explore the economic implications of less efficient heat integration but with the pro of potential heat sales in Bornholm's district heating network. Doing a comparison between the methanol production costs when using SOEC or AEC was also considered interesting as AEC is currently more technologically mature than the SOEC. The comparative study between the two electrolyzer technologies can be found in *Section* 7.6 of the *Appendix*. The main takeaways from this comparison of electrolyzer technologies under the assumptions of this study are: using the AEC instead of SOEC results in a strictly higher fuel production cost, with increases ranging from 2.4-7.9% depending on the analyzed MeOH production pathway

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On the other hand, the excess heat production is strictly larger with AEC, with increases ranging from 21-159% increase in excess heat when operating an e-biomethanol plant supplied by either AEC or SOEC. However, as demonstrated in *Section* 7.6 of the *Appendix* whether or not the by-product sale of heat is achieved (AEC vs SOEC) is not a deciding factor on the feasibility of a small-scale methanol PtX plant.

The techno-economic characteristics used for the electrolyzers in the model are collected in *Table* 43 and *Table* 44 (also found in *Section* 7.1 of the *Appendix*). The efficiency of the electrolyzers also varies with the load, as further detailed in the load curve included in *Figure* 25 in the *Appendix*. Initially, the model employed a piece-wise linearization approach to represent this load-dependent efficiency. However, subsequent analysis revealed that efficiency variation with load had a minimal impact on the overall results. Therefore, for simplicity and practicality, the electrolyzer's efficiency was treated as approximately constant across different scenarios. This simplification yielded consistent results without compromising the accuracy of the model.

Available biogenic carbon resources

An overview of the base case availability of biogenic carbon resources is presented in *Table* 18. The availability of these resources varies depending on the chosen production pathway. The amounts shown in *Table* 18 represent the initial distribution and quantities of these resources specific to each pathway. These biogenic carbon resources are exclusively sourced from the island of Bornholm, with no external imports considered in the analysis. A detailed breakdown of these biogenic carbon resources is provided in *Table* 21 in the following sections. All the data regarding the availability of biogenic carbon in Bornholm was provided by BEOF and can be found in WP1 [7].

Table 18: Yearly biogenic carbon resources available for each pathway, as found in WP1, used in the base case analysis.

Carbon source	**PS-CO_2**	**Biogas**	**Wood (chips and waste)**	**DAC-CO_2**
[kton/yr]	42.92	64.48	54.55	350.00

Note: CO_2 and CH_4 are considered as ideal gases. The biogas is assumed to be 60%CH_4-40%CO_2, with a density of 1.19kg/m^3.

Each production pathway utilizes a different type of biogenic carbon for the generation of methanol. The quantification and allocation of these resources are critical in understanding the potential of each pathway. While *Table* 18 illustrates the framework or baseline case of resource distribution, the scenarios analyzed in this study involve optimization and reallocation of these resources. This redistribution is aimed at optimizing the efficiency and output of specific production pathways.

Fuel produced and synthesis routes

The small-scale PtX plant study was dedicated to producing methanol (MeOH), an e-biofuel. In this case, 4 different production pathways were considered depending on the source of biogenic carbon used.

The methanol synthesis in each route is done in a reactor with the catalyst Cu/ZnO/Al2O3. The reaction is exothermic and a source of heat for district heating. The amount of excess heat available varies depending on the route, as the heat integration of the plant and the reactions vary. Each of these pathways needs different technological and operational requirements, and are described in the next pages.

- Pathway 1 - Methanol (MeOH) from point-source CO_2: The point-source CO_2 comes from the CO_2 fraction of the biogas produced on Bornholm. The CO_2 is procured at a price equivalent to the estimated cost of separating the methane and CO_2 in the biogas (0.131€/kg). The CO_2 undergoes a catalytic hydrogenation in a methanol synthesis loop, where CO_2 and H_2 react to form MeOH.

All units in the system are powered by renewable energy sources -i.e. the offshore wind farm (OWF) and the solar park-. *Figure* 14 shows an schematic illustration of Pathway 1, emphasizing the diverse units taken into account when modelling the methanol production in OptiPlant.

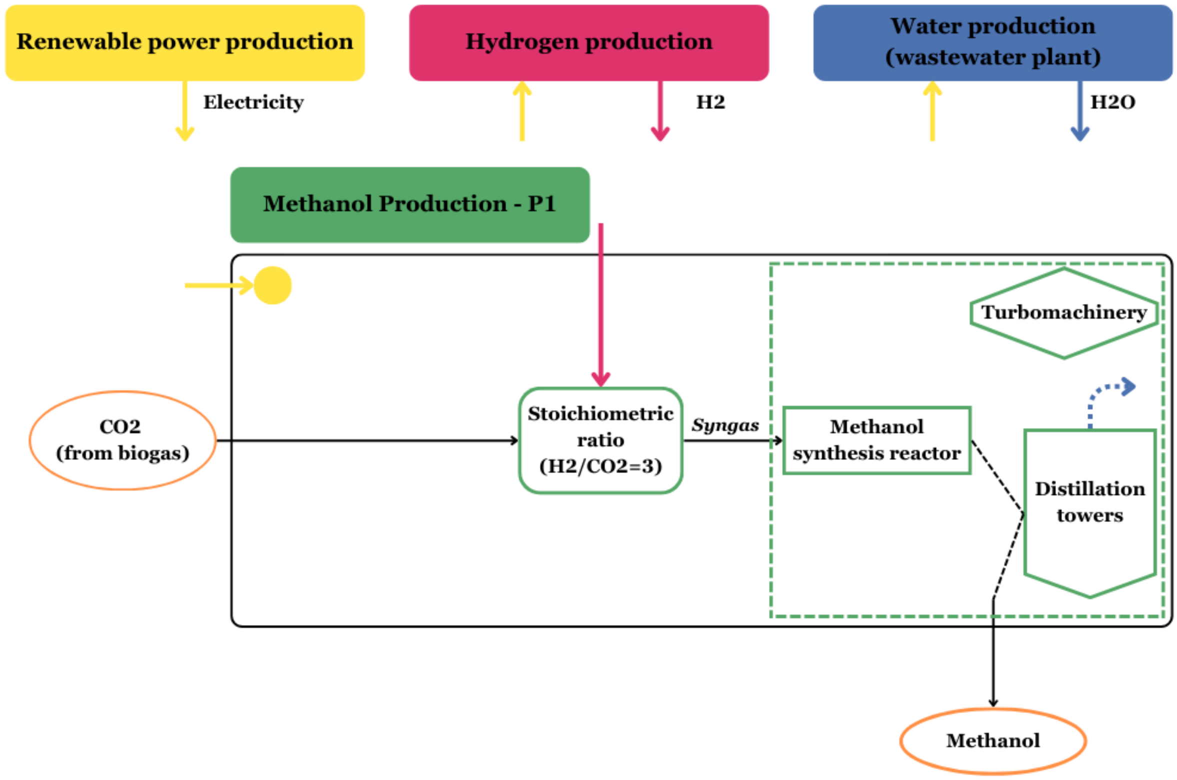

Figure 14: Schematic overview of methanol production in Pathway 1, showing the diverse units modeled in OptiPlant for the production of methanol from point-source CO2.

- Pathway 2 - Methanol (MeOH) from biogas: The biogas is procured from the local production of Bornholm at an assumed cost of 0.404 €/kg. This price is the combined cost of production + the value of the green certificate of origin, which biogas is eligible for [46][47]. The biogas is mixed with steam and reformed in an electrical steam reformer to create syngas of primarily CO and H_2. H_2 is added to the syngas to ensure that the stoichiometric ratio of H_2 and CO is 2 (the desired ratio for MeOH synthesis). This entire process is also powered by renewable energy sources. *Figure* 15 presents a schematic illustration of Pathway 2, focusing on the units considered when modelling the methanol production process in OptiPlant.

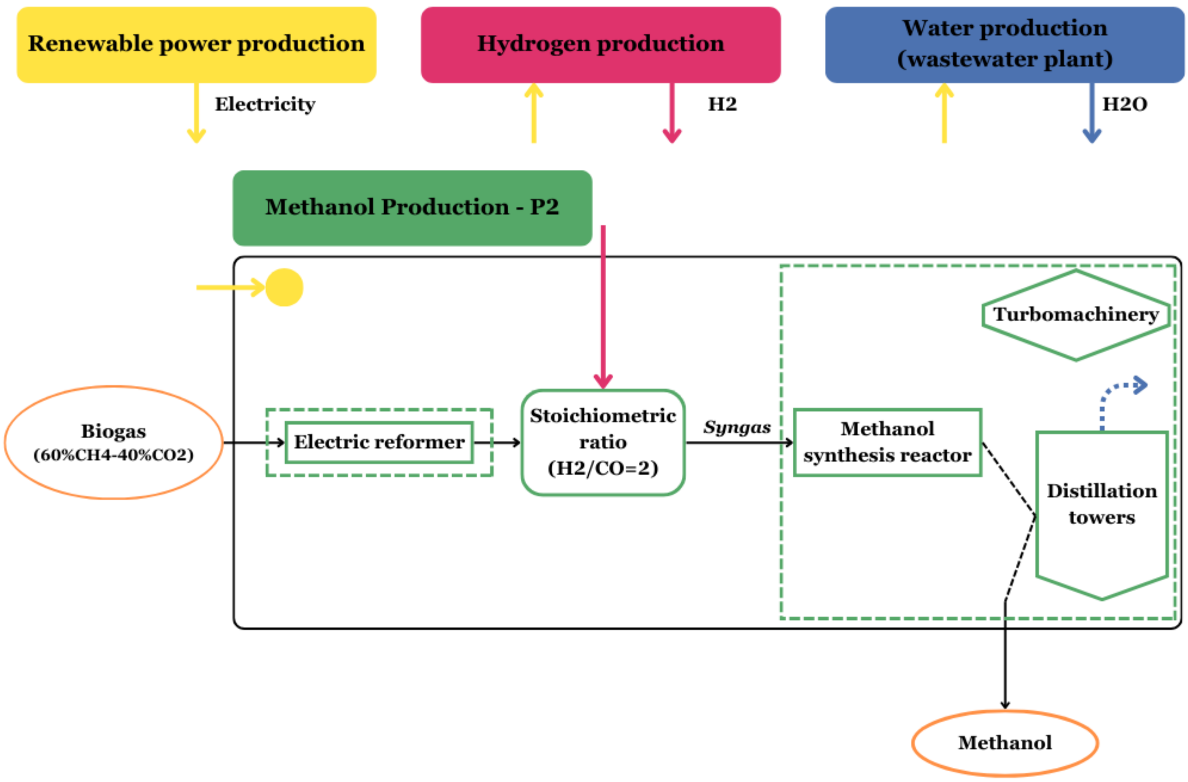

Figure 15: Schematic overview of methanol production in Pathway 2, showing the diverse units modelled in OptiPlant for the production of methanol from biogas (60%CH4-40%CO2).

- Pathway 3 - Methanol (MeOH) from wood: The biomass used as feedstock in this production option consists of wood chips and wood waste. The biomass undergoes a two-stage gasification (pyrolysis + gasification) and gas cleaning procedures, and is added extra H_2 from the electrolyzer to create a clean syngas suitable for methanol synthesis similar to Pathway 2. The wood chips are procured at 0.089 €/kg and the energy content of the biomass is assumed to be 12.5 MJ/kg. Similarly to the previous routes, the different units are also powered with the available RES. *Figure* 16 provides a detailed schematic of Pathway 3, showcasing the units used in OptiPlant to simulate the production of methanol from wood biomass.

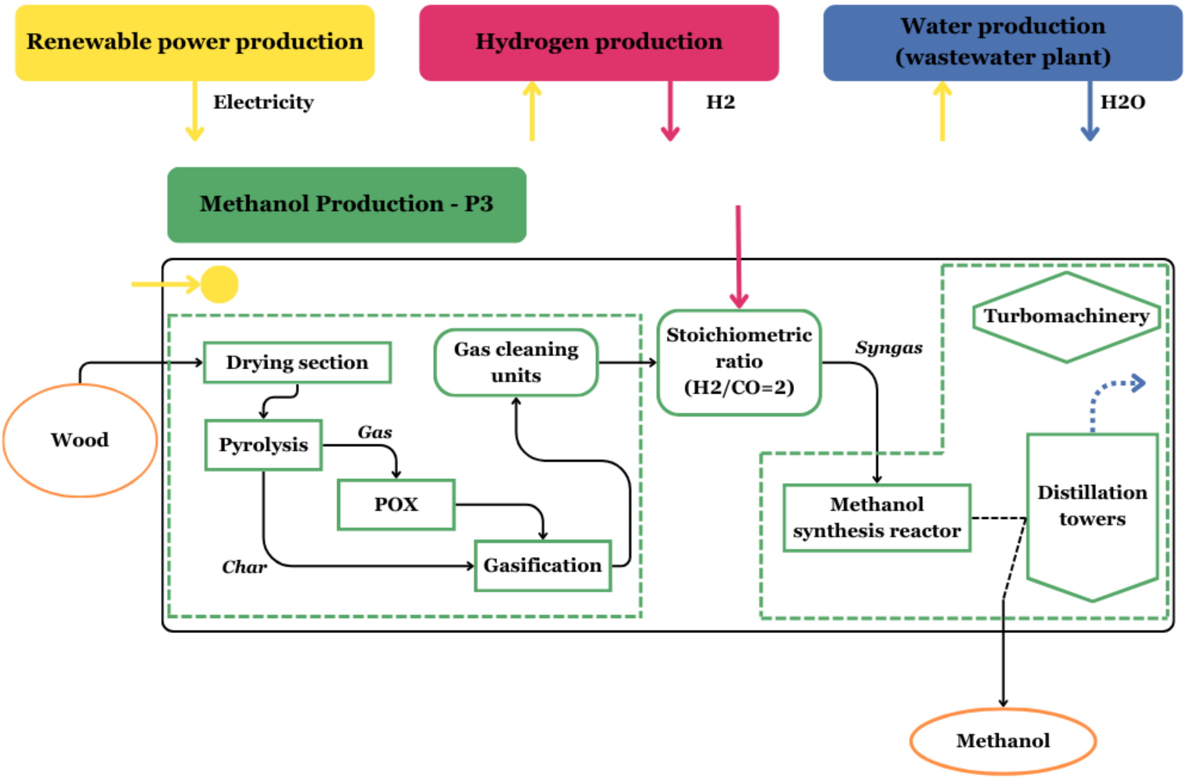

Figure 16: Schematic overview of methanol production in Pathway 3, showing the diverse units modeled in OptiPlant for the production of methanol from wood biomass.

- Pathway 4 - Methanol (MeOH) from DAC CO_2: Pathway 4 is similar to pathway 1 and only differs in the scale of operation and the source of CO_2. It is included as a means to enable the discussion of DAC on Bornholm as a basis for MeOH production. The scale of this production is not limited by the available biogenic carbon but by the maximal offshore wind farm overplanting planned for Bornholm (800 MW), which presents the upper limit of renewable energy production available for PtX-plants on Bornholm. The DAC is modelled as a separate plant component with its own CAPEX and OPEX. The whole system is powered by the renewable energy produced in the offshore wind and solar plants. *Figure* 17 illustrates the schematic layout of Pathway 4, highlighting the units taken into consideration when modelling the methanol production in OptiPlant.

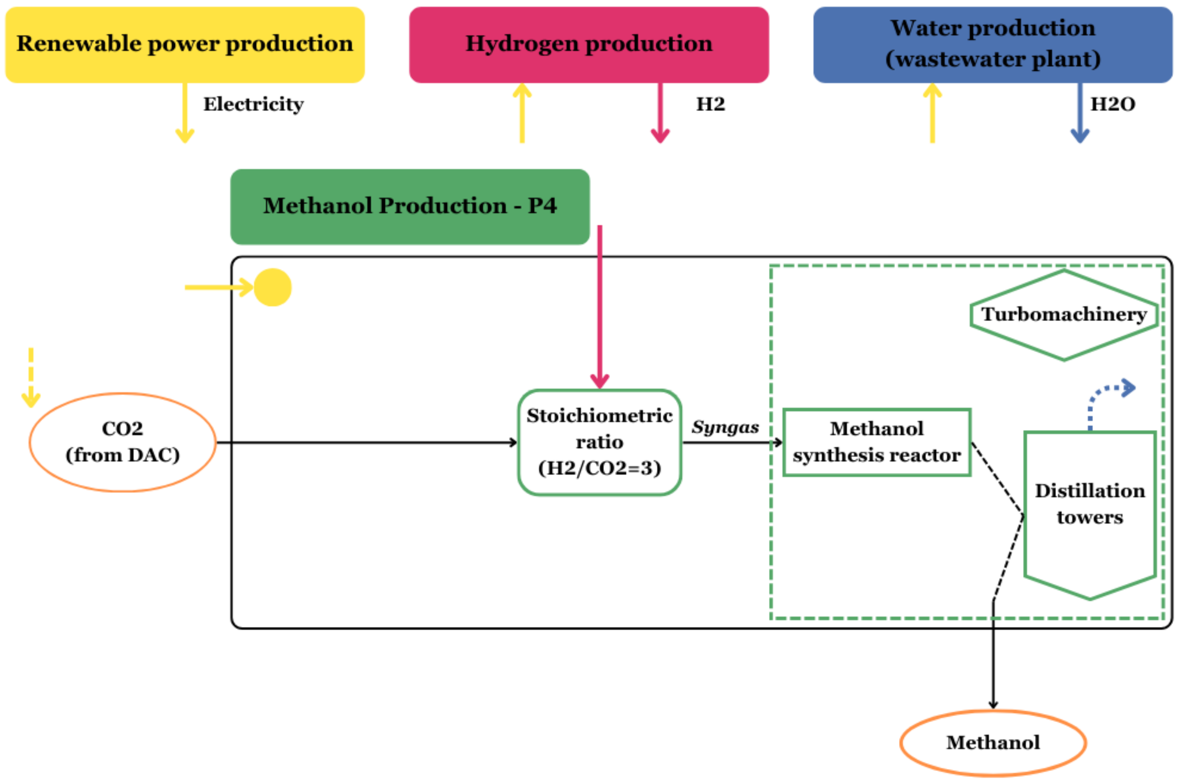

Figure 17: Schematic overview of methanol production in Pathway 4, showing the diverse units modeled in OptiPlant for the production of methanol from CO2 obtained by DAC.

- *Enhancement of methanol production with slow pyrolysis of biogas digestate*: In addition to these primary pathways, there is a potential opportunity to further enhance methanol production yield by incorporating the process of **Slow Pyrolysis**. This process is relevant to the pathways that produce biogas, as the dry matter digestate byproduct from anaerobic digestion of biomass could be utilized in a slow pyrolysis process. The slow pyrolysis primarily produces biochar, but also yields crude bio-oil and syngas, with compositions similar to those used in the described methanol production pathways. Thus, coupling the slow pyrolysis of the digestate dry matter could increase the yield of the previously mentioned methanol production pathways. The slow pyrolysis process is currently one of the main focus of Stiesdal's SkyClean project [3], which aims to integrate small scale pyrolysis plants in extension to existing biogas plants. *Figure* 18 shows a schematic illustration of the slow pyrolysis route and how it was modelled in OptiPlant for methanol production.

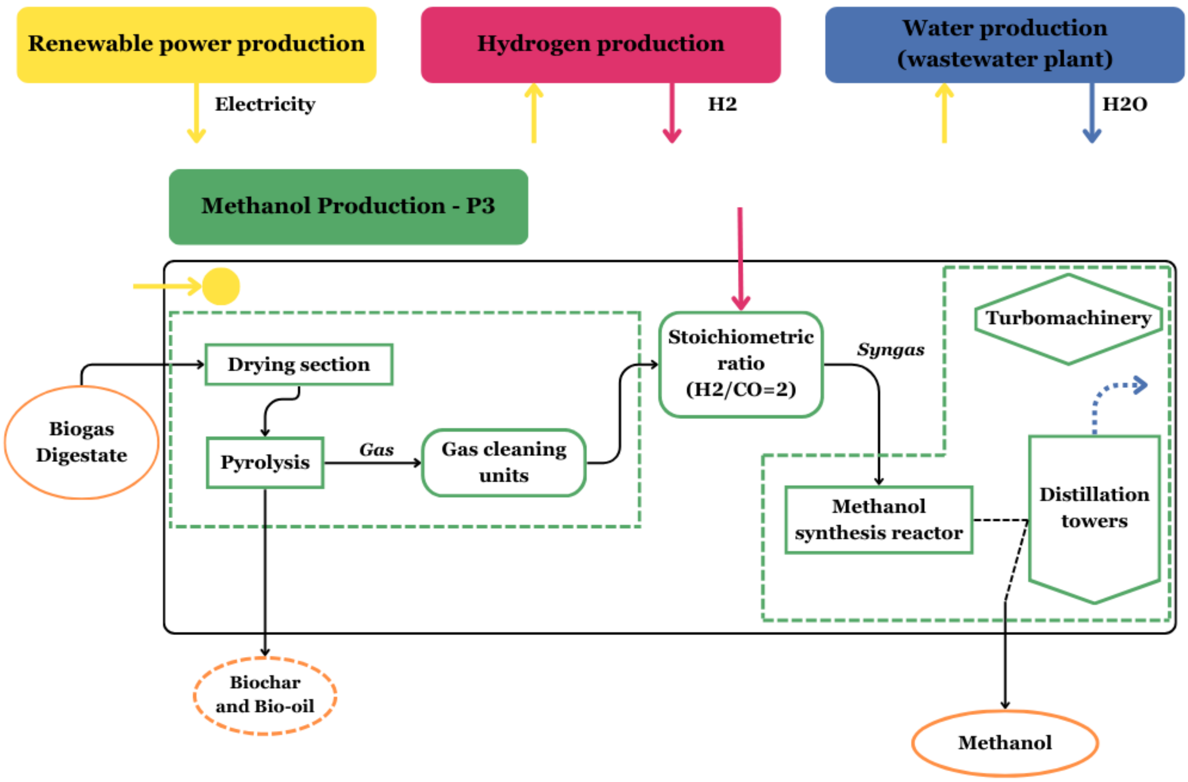

Figure 18: Schematic overview of methanol production when using slow pyrolysis from dry matter digestate -obtained as a byproduct of biogas production-.

To provide a coherent and comprehensive understanding, it is essential to note that each methanol production pathway -as illustrated in *Figures* 14, 15, 16, 17-, involves different units/components within the methanol production plant. This is primarily due to the variations in biogenic carbon inputs specific to each pathway. The unique composition of each plant plays a significant role in determining its operational dynamics and overall cost. All the units/components modelled for the methanol plant in each of the pathways are listed in *Table* 19. The purchase price of the different input biogenic C sources for each scenario are gathered in *Table* 20.

Table 19: Units/components considered in OptiPlant when modelling the methanol plant for each production pathway

MeOH plant units/components	
Pathway 1 (PS CO_2)	Methanol synthesis reactor, distillation towers, and turbomachinery
Pathway 2 (biogas)	Electric reformer, methanol synthesis reactor, distillation towers, and turbomachinery
Pathway 3 (wood)	Drying section, pyrolysis unit, POX, gasifier, gas cleaning unit, methanol synthesis reactor, distillation towers, and turbomachinery
Pathway 4 (DAC CO_2)	Methanol synthesis reactor, distillation towers, and turbomachinery

Note: The slow pyrolysis of digestate was simulated similarly to pathway 3 -see *Figure* 18-

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Table 20: Purchase prices considered in the model for the different biogenic carbon sources used in the methanol production pathways.

Carbon source	**PS-CO_2**	**Biogas**	**Wood (chips and waste)**	**DAC-CO_2**
[€/kg]	0.131[1]	4.04[2]	0.089[3]	*-Cost of DAC plant-*

Note: CO_2 and CH_4 are considered as ideal gases. The biogas is assumed to be 60%CH_4-40%CO_2, with a density of 1.19kg/m^3. The energy content of the biomass is assumed to be 12.5 MJ/kg
[1] Based on estimates from [6] on the cost of separating CO_2 and CH_4 in biogas.
[2] Based on estimated production cost of biogas [46] and estimated green certificate value of biogas [47].
[3] Medium predicted wood chips prices for 2030, based on [48]

It is also important to clarify that the rest of the aspects of the methanol production process, such as renewable power production, hydrogen production, and wastewater treatment, are modelled the same way across all pathways in the OptiPlant model.

The uniformity in modelling these elements ensures a level of consistency and comparability when analyzing the different pathways and scenarios within the study. The techno-economic characteristics used for the different units involved in the fuel production for all of the units for all the pathways/processes are included in *Table* 15 and *Table* 16 (also included in textitSection 7.1 of the *Appendix*). Finally, *Figure* 19 below presents a flowchart detailing the specific resources utilized in each methanol production pathway/process (including slow pyrolysis) for a clearer understanding.

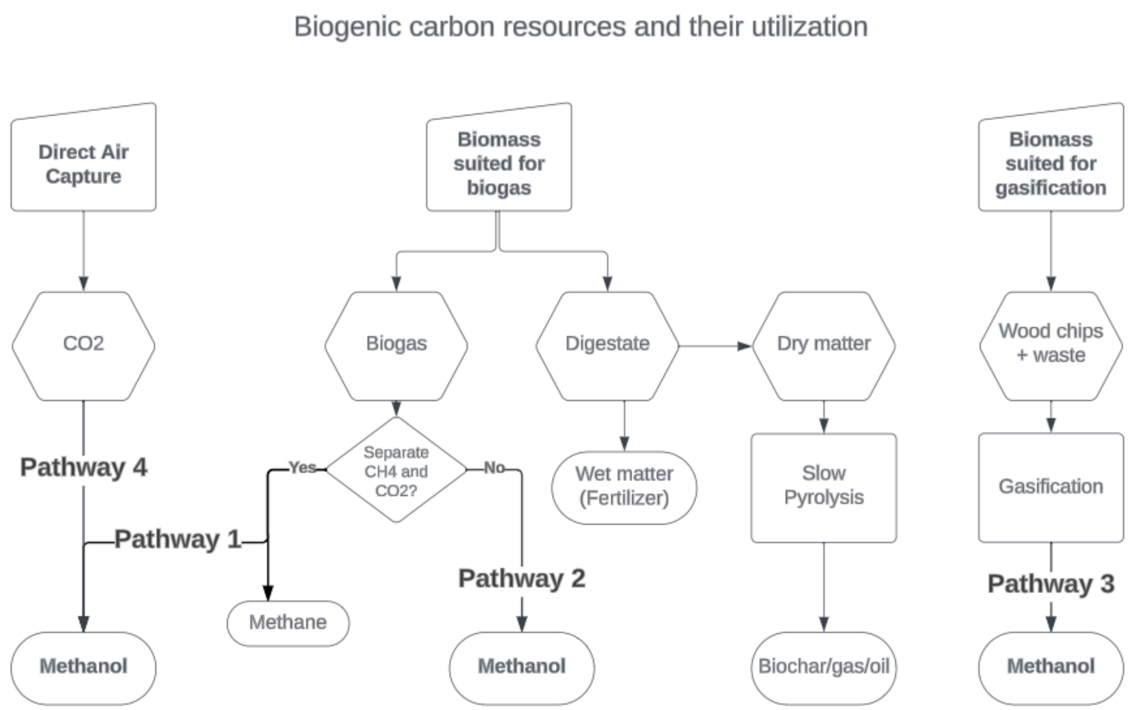

Figure 19: Flowchart of the utilization of biogenic carbon sources and where each presented technological pathway is relevant/utilizes the carbon for MeOH production.

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Fuel demand

The fuel demand projected in the study is on an annual basis. Even though the fuel demand is the main constraint of the OptiPlant model, for this investigation the fuel demand is derived based on the available resources. Referring to *Table* 15 and its production rates, the annual demand of MeOH for each pathway is found by multiplying the production rate with the resource available as specified in *Table* 18. No constraints related to the storage or transport of the produced e-biofuel were considered by the model.

To have a clearer understanding of the methanol quantity required to meet various energy needs in Bornholm, it is useful to provide some of the island's sectoral energy consumption, as outlined in the Bornholm Energy Strategy [19]. For context, the local industry in Bornholm is estimated to use process energy equivalent to approximately 18.5 GWh/y, translating to 3.34 kton/y of MeOH. The heavy transportation on Bornholm (vans, trucks, bus services, and farming machines) uses energy equivalent to 155 GWh/y of energy ca, which corresponds to 28.03 kton/y of MeOH. The demand for Bornholm's ferry company is around 237GWh/y, equivalent to 42.86 kton/y of MeOH. Finally, taking into account all the vessel segments in the Baltic Sea, these ships consume a total of 4,360,000 tons of fuel per year. This fuel usage represents roughly 43600 GWh/y of energy or the energy content of 7884.26 kton/y of MeOH.

Sizing method

As previously described, the model can process weather data in two distinct ways: deterministic and stochastic. The deterministic method utilizes weather data from a single year for Power-to-X plant sizing, providing specific insights into plant performance under particular weather conditions. In contrast, the stochastic method incorporates weather data from multiple years, addressing variability and uncertainty and offering a broader view of plant design and performance across different weather scenarios.

For this investigation, only the deterministic approach using an average/typical weather year (2020) was applied. The primary reason for this decision is based on findings from Phase 1, which indicated that economic indicators from a deterministic model for an average/typical year closely align with those obtained from a stochastic model. Additionally, the combination of solar and wind renewable energy sources in this study leads to more stable and consistent power profiles throughout the year, reducing uncertainties. Furthermore, the smaller scale of the plant results in less variability in energy consumption and operation. These factors collectively justify the use of the deterministic method for Phase 2 objectives, eliminating the need for the added complexity of stochastic modelling.

4.1.3 Scenario design and resulting scenarios

This investigation analyzed a set of unique methanol production options, taking into account the different parameters outlined in the sections above. Initially, each of the 4 described production pathways was analyzed individually, serving as foundational or framework scenarios. Then, the focus shifted to exploring how the pathways with the most promising potential (and also the slow pyrolysis process) could be implemented, either individually or in combination.

The design of the different scenarios was done with the main goal of maximizing methanol production using Bornholm's biogenic carbon resources sustainably and cost-effectively. To do so, the findings of WP1 [7] were used as the foundation: WP1 identified the available biogenic carbon resources on Bornholm, with the results highlighted in *Table* 21 below.

Table 21: Bornholm's yearly biomass resources and the suggested use case for each biomass type [7].

Biomass type	**Suitable for**	**Potential source** [tons/year]	**Biogas yield** [Nm3/ton]	**Biogas potential** [1000 m3/year]
Liquid manure	Biogas	547530	20	11000
Deep litter	Biogas	29700	89	2500
Horse stable deep litter	Biogas	n/a	n/a	n/a
Sludge (dry matter)	Biogas	2400	130	300
Seaweed (15% sand)	Biogas	3000	40	100
Secondary crops	Biogas	4450	39	200
Landscaping	Biogas	2195	76	1107
Garden waste	Biogas	8920	76	2285
Slaughterhouse waste	Biogas	9000	350	3150
KOD[1]	Biogas	2350	152	400
Dairy waste as KOD[1]	Biogas	5000	350	1750
Straw	Biogas	88480	355	31500
Wood chips	Two-stage gasification[2]	50000	*	*
Wood waste	Two-stage gasification[2]	4550	*	*
Digestate dry matter[3]	Pyrolysis[2]	70000	*	*
Total suited for	Biogas	703025	77	**54192**
Total suited for	Gasification	**54550**	*	*
Total suited for	Pyrolysis	**70000**	*	*

[1] KOD stands for 'Kildesorteret organisk dagrenovation' ∼ Sorted organic household waste.
[2] The two-stage gasification includes the processes of pyrolysis and gasification.
The assumed energy content of wood chips and waste is 12.5 MJ/kg and its buying price is 0.089€/kg.
[3] Digestate dry matter is assumed to be 10% of biomass input on average.

Furthermore, the action plan described in Biogasplan Bornholm -a report made by BLF-[49], also played a significant role in shaping the scenario design. The report outlines two potential scenarios for biogas production on the island. The 'Max-gas' scenario aims to maximize biogas production, with an expected yield of 30-34 million Nm^3 annually. This contrasts with the 54.19 million Nm^3 of potential biogas production identified in WP1, which takes into account the use of all available biomass sources, including a higher allocation of straw. Notably, Biogasplan Bornholm's plan does not incorporate the full potential use of straw, half of which is currently utilized for central heating via combined heat and power (CHP) plants. However, the introduction of an e-biomethanol plant with the capability of generating excess process heat could reduce the dependency on CHP heating, presenting a case for greater straw utilization in biogas production. This alternative approach, incorporating an increased use of straw for biogas and its implications, was considered interesting to be further explored in this investigation.

The preliminary analysis of the four methanol production pathways individually yielded results on the potential fuel production costs and the total amount of fuel produced. These results are displayed on *Table* 22.

Table 22: Fuel production costs of different methanol production pathways under the deterministic analysis (typical/average weather year, 2020). The MeOH production for each pathway depends on the available biogenic carbon.

	Pathway 1 (PS CO_2)	**Pathway 2 (biogas)**	**Pathway 3 (wood)**	**Pathway 4 (DAC CO_2)**
Fuel production cost [€/MWh]/[€/kg]	282.51/1.56	206.24/1.14	199.08/1.10	306.84/1.70
Total amount of produced fuel [GWh/year]/[kton/year]	172.67/31.24	416.09/75.27	257.79/46.64	1408.09/254.73

The analysis of the four methanol production routes shows significant differences in both the fuel production costs and the total amount of fuel produced across the pathways. Pathway 3 (MeOH from wood) is the cheapest option with a fuel production cost of 199.08 €/MWh (1.10 €/kg), while Pathway 4 (MeOH from DAC CO_2) has the highest cost at 306.84 €/MWh (1.70 €/kg) even considering significant economies of scale. Despite its higher cost, Pathway 4 has the larger methanol production potential, primarily due to the unlimited availability of atmospheric CO_2 as a biogenic carbon source. However, it's important to consider that DAC technology is still not fully mature, and its implementation requires significant land use. Consequently, this pathway was excluded from the scenario design when combining multiple methanol production methods. The detailed breakdown of the total system costs and optimal installed capacities for each unit for all production pathways can be found in *Section* 7.7 of the *Appendix*.

Taking into account all the aspects mentioned above, four unique study scenarios were designed to explore the potential for methanol production by combining the previously described production pathways and increasingly using more of the available biogenic carbon in Bornholm. The detailed descriptions of each scenario are as follows:

■ **Scenario 1 - Biogas reforming to MeOH:** This scenario focuses on utilizing the full potential of biogas production in Bornholm, specifically for direct conversion into methanol. The main goal is to achieve efficient methanol production at competitive costs. As shown in *Table* 21, using all the available biogenic carbon streams for anaerobic digestion (703,025 tons/y), the potential biogas production is 54.2 mio. Nm^3 annually. This scenario explores the feasibility of transforming this biogas into methanol by means of Pathway 2.

■ **Scenario 2 - Biogas reforming to MeOH + Pyrolysis of digestate:** Expanding on the previous case, this setup integrates the biogas reforming in scenario 1 and the slow pyrolysis of the digestate that results from the biogas production. From WP1 inputs, it is estimated that approximately 10%wt of the biomass input to the biogas process results in dry matter digestate (i.e. around 70,000 tons/y) [7]. Pyrolizing this digestate produces syngas suitable for methanol production plus biochar and bio-oil. In the OptiPlant model, both syngases from the biogas reforming and the digestate pyrolysis are combined in a single stream to produce methanol, thereby increasing the total methanol yield. This scenario explores the integration of Pathway 2 with the enhancement provided by digestate slow pyrolysis, evaluating how this combination effectively boosts the efficiency and overall output of the methanol production process

■ **Scenario 3 - Biogas reforming & two-stage wood gasification to MeOH:** This scenario combines the processes of biogas reforming (as explored in scenario 1) with the two-stage wood gasification, exploiting the maximum potential of both biogas and wood resources available on Bornholm. As previously mentioned, the available biogenic carbon streams for anaerobic digestion sum up to 703,025 tons/y, yielding a potential biogas production of 54.2 mio. Nm^3 annually. Additionally, the available wood resources for the two-stage gasification amount to 54,550 tons/y -see *Table* 21-.

This scenario explores the parallel operation of Pathway 2 and Pathway 3, evaluating the increase in methanol production and the potential benefits of economies of scale and improved process efficiency.

- **Scenario 4 - Biogas reforming & two-stage wood gasification to MeOH + Pyrolysis of digestate:** Expanding on scenario 3, this setup incorporates the biogas reforming, the two-stage wood gasification and the slow pyrolysis of digestate, representing the fullest exploitation of Bornholm's biogenic carbon resources for methanol production. This approach aims to explore the highest potential for methanol yield by using all carbon streams available on the island, as identified in WP1, without resorting to external carbon imports. The scenario employs 703,025 tons/y of biomass for biogas production, 54,550 tons/y of wood for two-stage gasification, and approximately 70,000 tons/y of dry matter digestate for pyrolysis. This scenario explores the simultaneous implementation of Pathway 2 and Pathway 3, with the enhancement provided by digestate slow pyrolysis, trying to determine the feasibility and quantify the maximum achievable methanol production on Bornholm. Furthermore, this holistic approach aims to provide a comprehensive evaluation of the island's methanol production capabilities, considering all available biogenic resources and their optimal and sustainable utilization.

Building upon the previously presented biogenic carbon resources (*Table* 21), the input carbon resources utilized in each of the methanol production scenarios are comprehensively detailed in *Table* 23, as shown below:

Table 23: Yearly biogenic carbon resources available for each scenario

	Process	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
Biogas [kton/y]	*Reforming*	64,280	64,280	64,280	64,280
Wood biomass [kton/y]	*Two-stage gasification*	0	0	54,550	54,550
Digestate [kton/y]	*Pyrolysis*	0	70,000	0	70,000

The scope of the scenario analysis was limited to a single weather year, as it was considered sufficient to yield relevant and significant results for this study. This selective approach enabled a comprehensive analysis of the feasibility and potential of e-methanol production in Bornholm under various conditions and plant configurations. Initially, each of the four methanol production pathways was individually assessed to establish the study's framework. Subsequently, the investigation focused on the investigation of the four scenarios derived from these pathways. The obtained results and in-depth discussion from all these analyses are presented in the following section.

4.2 Results and discussion

This section presents and discusses the outcomes derived from simulating the scenarios developed in Phase 2 for the small-scale PtX plant using the OptiPlant tool. As outlined in previous sections, this study focused on the feasibility and implications of small-scale production of methanol in Bornholm using the island's biogenic carbon resources. By conducting deterministic analyses, various scenarios and configurations to optimize production costs, plant size, and resource utilization were explored.

The results presented in this section offer detailed insights into optimal plant sizing and key economic indicators, including total annualized system costs and fuel production costs for the analyzed methanol production scenarios. Additionally, supplementary analyses were also conducted. These include assessments of water resource availability, integration of excess heat into the district heating system, sensitivity analyses on various parameters, and evaluating Bornholm's competitiveness as a methanol production location. These additional evaluations aim to determine if it is feasible to use the island's carbon resources to satisfy the local fuel/energy demand and help decarbonize the island through e-methanol production.

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

Phase 2 investigation only explored the deterministic approach to sizing the methanol PtX plant using a single year's weather data. In line with the objectives set out in the previous section, a total of 4 potential methanol production scenarios were evaluated under the weather conditions of a typical/average weather year.

The average/typical year 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. The decision to use only data from an average/typical weather year is appropriate and sufficiently accurate for this small-scale plant study. This approach aligns with Phase 1 findings, where economic indicators from a deterministic average weather year closely matched those from a stochastic model. Furthermore, the combination of solar and wind power sources in this study provides more stable and predictable energy profiles, thereby minimizing uncertainties. Additionally, the smaller size of the plant naturally leads to less variability in its operation, further supporting the adequacy of using only the deterministic approach for this analysis. 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 are structured in two key parts. First, the optimal sizing and cost analysis for the 4 methanol production scenarios is presented. Next, additional findings on the supplementary analyses described above are also presented. Each of the two parts of the study is important in the successful design and operation of the methanol PtX plant.

4.2.1.1 Optimal PtX plant sizing and cost analysis for the study scenarios

The optimal sizing of the different PtX plant units for the 4 described methanol production scenarios using weather data from 2020 (typical/average year) is displayed in *Table* 24 presented on the following page.

Table 24: Optimal sizing of the Power-to-X plant units for different methanol production scenarios under the deterministic analysis (typical/average weather year, 2020). The MeOH production for each scenario depends on the available biogenic carbon.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Offshore Wind Farm [1] **[MW]**	55.36	59.00	102.62	105.76
Solar PV Park [2] **[MWp]**	40.00	40.00	40.00	40.00
Electrolysis plant (SOEC) [t H_2/h]/[MW_{in}]	0.81/35.01	0.83/35.87	1.60/69.12	1.61/69.5
Wastewater treat. plant [m^3 H_2O/h]	9.12	9.28	17.98	18.01
Methanol synth. plant				
MeOH synth. reactor [t MeOH/h]	9.82	11.06	15.85	17.20
Electrical reformer [t syngas/h]	10.4	10.5	10.9	11.1
Pyrolysis unit [MW_{in}]	*	28.8	*	28.8
Gasification unit [t syngas/h]	*	*	5.9	5.9
Batteries [MWh]	90.97	99.35	108.98	119.77
H_2 storage (buried pipes) [t]	58.87	62.23	117.07	115.74

[1] The model selected the SP379-HH150 turbine as the optimal choice from the available catalogue for all model runs.
[2] The model selected 1-axis tracking solar PV as the best solar PV technology for all model runs. The capacity of the solar park was capped at 40MW.

The optimal sizing results for the Power-to-X plant units across the four methanol production scenarios in *Table* 24 show a consistent trend of increasing capacity from Scenario 1 to Scenario 4. This pattern reflects the progressive integration of additional biogenic carbon resources in each subsequent scenario, leading to a corresponding increase in the methanol production potential.

Scenarios 1 and 2, primarily based on biogas reforming to produce methanol, exhibit similar optimal capacities. However, Scenario 2 includes an enhancement through the pyrolysis of digestate, which slightly elevates its installed capacities compared to Scenario 1.

Scenarios 3 and 4 combine the biogas reforming with two-stage wood gasification and have similar installed capacities. They show a notable increase in the optimal capacities of the plant units compared to 1 and 2, reflecting the expanded biogenic carbon availability (biogas and wood). In Scenario 4, the inclusion of digestate pyrolysis further enhances the plant's capability, which results in a slight overall increase in the capacity of all units.

Similarly to Phase 1, the methanol production cost and total annualized system cost for each of the studied scenarios were also examined under two distinct approaches:

- Standard cost analysis: This analysis is conservative as it primarily examines the total system costs and the fuel production costs for each of the studied scenarios without considering the revenues from by-products.

- Cost analysis with by-products selling revenue: In this more optimistic approach, the selling of by-products from methanol production are taken into account, providing a revised economic evaluation. In the context of methanol production, the monetized by-products consist of heat, oxygen, and biochar. The by-product allocation and local market prices are clearer and better matched to the demand expected in Bornholm, compared to larger-scale operations where these factors can be more complex and less certain. This approach allows for a more accurate assessment of how these by-products contribute to the economic viability of the project. The sale or further processing of the pyrolysis bio-oil produced in Scenarios 2 and 4 were not considered in this part of the study due to the high uncertainties related to the market demand and prices, transformation processes, and other considerations that were outside the scope of this particular work package.

STANDARD COST ANALYSIS

For the **standard cost analysis**, *Figure* 20 shows a graphical representation of these economic indicators for the four specific methanol production scenarios using weather data of an average/typical year (2020). In the graph, each pathway 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 annuity values considered for each of the PtX plant facilities are displayed in *Section* 7.1 of the *Appendix*. 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. The fuel production costs are equal to the total annualized system cost per energy produced yearly. Finally, the fuel production volumes for each case are displayed under the scenario name on the x-axis. It is assumed that the energy density for MeOH is 5.53 MWh/ton [50].

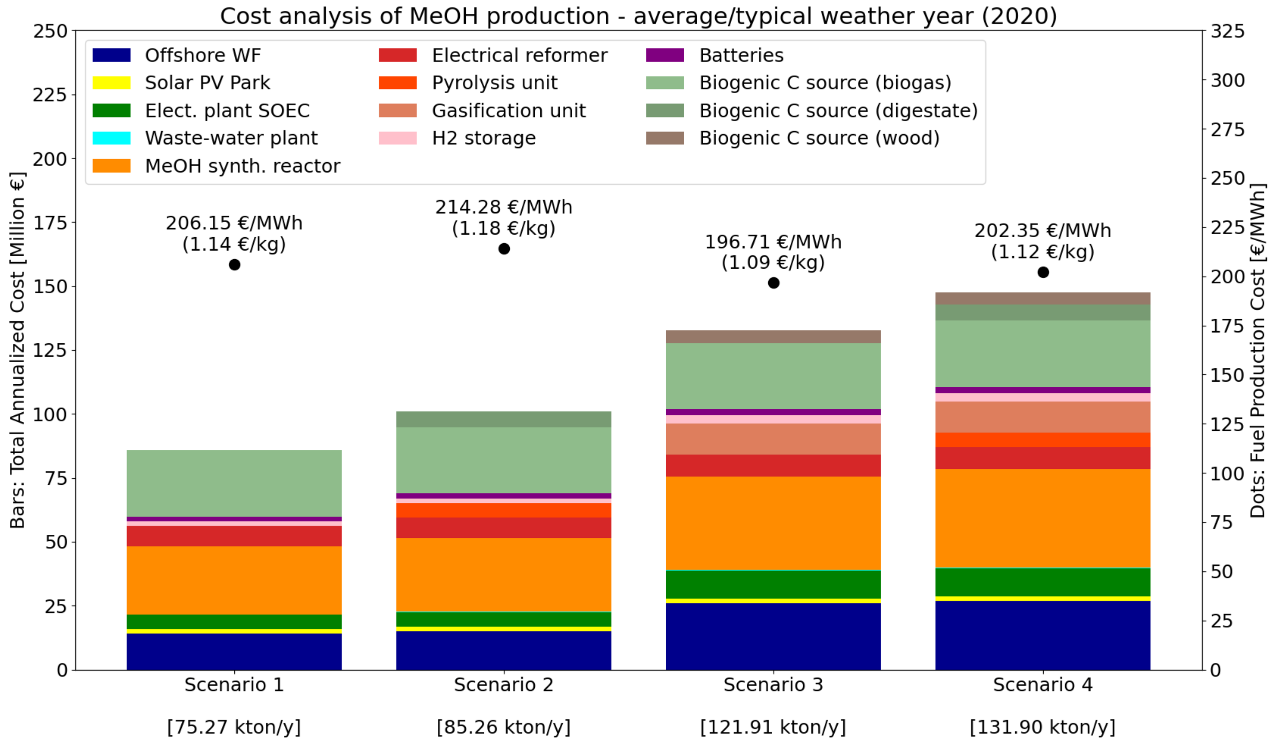

Figure 20: Comparative cost analysis for the 4 studied scenarios in an average/typical weather year (2020). **Standard cost analysis.**

Table 25 provides a numerical summary of the total annualized system cost and *Table* 26 shows the yield of methanol and by-products and the fuel production costs. This allows for a quick reference and a clearer visualization of the broken-down costs of the different methanol production scenarios.

Table 25: Breakdown of the annualized total system cost for the small Power-to-X plant by unit for different methanol production pathways under the deterministic analysis (typical/average weather year, 2020) -all costs are in [M€/year]-. **Standard cost analysis**. The MeOH production for each scenario depends on the available biogenic carbon.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Offshore Wind Farm	13.98	14.90	25.91	26.71
Solar PV Park	1.91	1.91	1.91	1.91
Electrolysis plant (SOEC)	5.58	5.68	11.01	11.03
Wastewater treatment plant	0.15	0.15	0.29	0.29
Methanol synth. plant				
MeOH synth. reactor	26.68	28.79	36.49	38.54
Electrical reformer	8.00	8.05	8.40	8.53
Pyrolysis unit	*	5.55	*	5.57
Gasification unit	*	*	12.22	12.22
H_2 storage	1.64	1.74	3.27	3.23
Batteries	1.91	2.09	2.29	2.52
Biogenic C source (biogas)	25.96	25.96	25.96	25.96
Biogenic C source (digestate)	*	6.23	*	6.23
Biogenic C source (wood)	*	*	4.85	4.85
TOTAL [M€/year]	85.81	101.04	132.61	147.59

From the results displayed in *Figure* 20 and *Table* 25, one can observe that the methanol synthesis reactor consistently represents the largest cost component across all scenarios, which is mainly due to the high cost of the catalyst. This is followed by the cost of obtaining the biogenic C sources, particularly biogas, which was assumed to have a purchase price of 0.404 €/kg. The offshore wind farm is the third major cost component.

In terms of the overall cost distribution the methanol synthesis reactor contributes by 30%-40% of the total costs across the scenarios, the biogenic C sources account for about 20%-30%, and the offshore wind farm constitutes roughly 15%-20%. The remaining percentage of the total cost is distributed among the other units.

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Table 26: Fuel production costs of different methanol production scenarios under the deterministic analysis (typical/average weather year, 2020). **Standard cost analysis.** The MeOH production for each scenario depends on the available biogenic carbon.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Methanol production cost [€/MWh]/[€/kg]	206.15/1.14	214.28/1.18	196.71/1.09	202.35/1.12
Total amount of produced fuel [GWh/year]/[kton/year]	416.26/75.27	471.51/85.26	674.15/121.91	729.41/131.90
By-products				
Heat [GWh/year]	92.73	112.18	139.43	158.87
Oxygen [kton/year]	27.39	27.39	27.39	27.39
Biochar [kton/year]	*	12.31	*	12.31
Pyrolysis Oil [kton/year]	*	6.33	*	6.33

Looking at the results in *Table* 26, it can be noted that the cheapest option for methanol production is Scenario 3 at 196.71 €/MWh, while the most expensive is Scenario 2 at 214.28 €/MWh. The percentage difference in cost between these two scenarios is 8.93%.

In terms of fuel production yield, there is a pattern of increasing methanol production from Scenario 1 to Scenario 4 due to the progressive integration of additional biogenic carbon resources in each subsequent scenario. This increment in production ranges from a minimum of 75.27 kton/year in Scenario 1 to a maximum of 131.90 kton/year in Scenario 4.

When comparing Scenario 1 with Scenario 2, adding slow pyrolysis of biogas digestate in Scenario 2 leads to an increase in methanol production by 55.3 GWh/year and a cost rise of 8.09 €/MWh. For Scenarios 3 and 4, incorporating this pyrolysis in Scenario 4 similarly boosts production by 55.3 GWh/year, with an increase in the methanol cost of 5.64 €/MWh.

In the standard cost analysis, the sale of the by-products was not considered. It is important to note that the biochar and the pyrolysis bio-oil could be further processed/upgraded to produce methanol and slightly increase its yield. However, this aspect was not considered in this investigation due to the high complexity and lack of maturity of the procedures involved. The effect these considerations would have on the displayed results of the yield is expected to be of minimal significance. In the following section, the revenues from the sale of the mentioned by-products in the methanol economic metrics are considered.

COST ANALYSIS WITH BY-PRODUCT SALE

For the **cost analysis with by-products selling revenue**, *Figure* 21 visually represents the economic indicators for the four specific methanol production scenarios using weather data of an average/typical year (2020). As for the standard case, each pathway 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 annuity values considered for each of the PtX plant facilities are displayed in *Section* 7.1 of the *Appendix*. 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. In this case, the fuel production costs are equal to the total annualized system cost, both positive and negative (including by-product sale revenues), per energy produced yearly. The fuel production volumes for each case are also displayed under the scenario name on the x-axis. Again, it is assumed that the energy density for MeOH is 5.53 MWh/ton [50].

Selling prices for the by-products were sourced from literature or provided by project partners. The sale prices were set at 20 €/MWh for heat [1], 0.05 €/kg for oxygen [2], and 0.26 €/kg for biochar [3]. These values can vary due to different reasons and should be used as indicative values. This analysis tries to broadly assess the potential reduction of the fuel cost when by-products are sold.

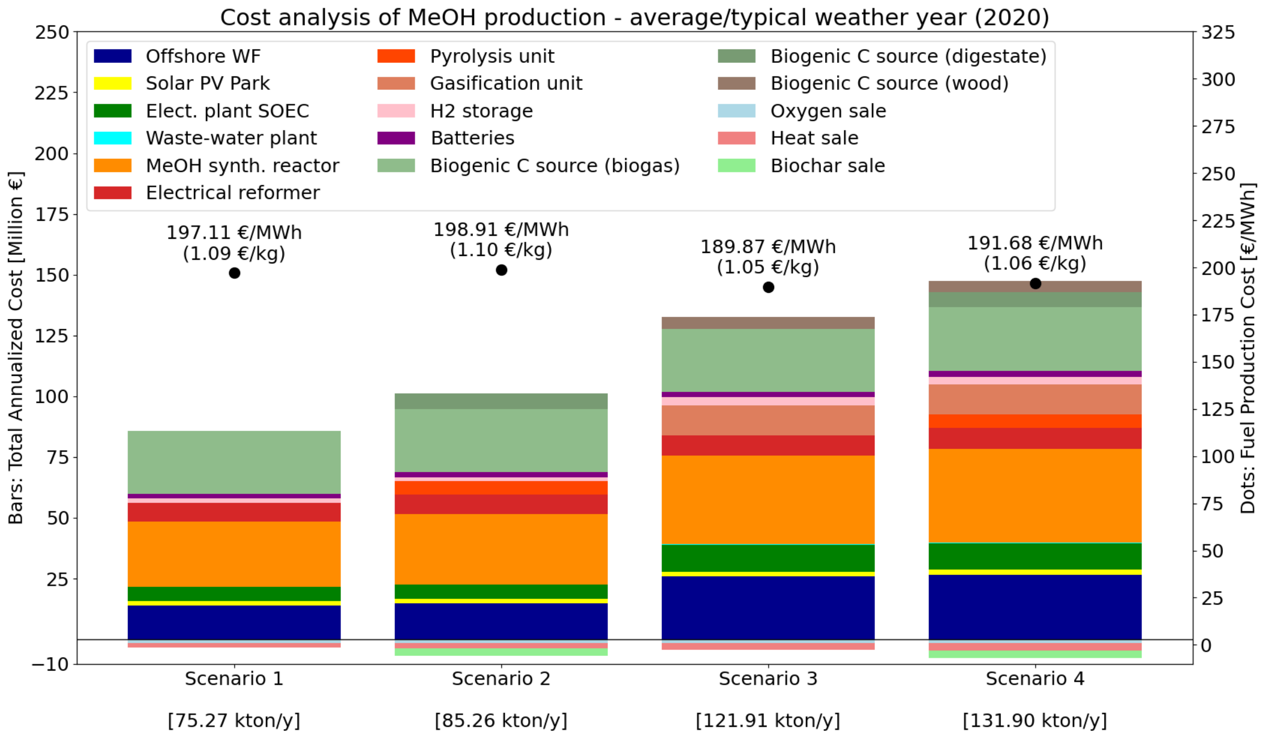

Figure 21: Comparative cost analysis for the 4 studied scenarios in an average/typical weather year (2020). **Cost analysis with by-product sales.**

To supplement the graphical representation, *Table* 27 displays a numerical breakdown of the revenues from the sale of heat, oxygen, and biochar (the costs of the different units are the same as the ones found in *Table* 25). *Table* 28 provides the fuel production cost for all scenarios within the small-scale PtX plant study taking into account the selling of the by-products. Notice that Pathway 3, biomass to MeOH, does not produce extra oxygen available for sale in Scenario 3 and 4 as all of the oxygen is assumed used in the gasifier [37].

Table 27: Breakdown of the by-product sale revenues for the small Power-to-X plant for different scenarios under the deterministic analysis (typical/average weather year, 2020) -all costs are in [M€/year]-. **Cost analysis with by-product sales**. The costs of the plant units are the same as the ones displayed in *Table* 25. The MeOH production for each scenario depends on the available biogenic carbon.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
...				
Heat sale	-1.85	-2.24	-2.79	-3.18
Oxygen sale	-1.37	-1.37	-1.37	-1.37
Biochar sale	0	-3.20	0	-3.20
'New' TOTAL (w/ by-product sale) [M€/year]	82.59	94.24	128.44	139.84

From the results displayed in *Figure* 21 and *Table* 27, it can be noted that the sale of by-products does not have a significant contribution on reducing the total annualized system costs. The biochar sale represents the higher revenue from selling by-products (Scenarios 2 and 4), followed by the heat sale revenue (all Scenarios).

Table 28: Fuel production costs of different methanol production scenarios under the deterministic analysis (typical/average weather year, 2020). **Cost analysis with by-product sales.** The MeOH production for each scenario depends on the available biogenic carbon.

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
Methanol production cost [€/MWh]/[€/kg]	197.11/1.09	198.91/1.10	189.87/1.05	191.68/1.06
Total amount of produced fuel [GWh/year]/[kton/year]	416.26/75.27	471.51/85.26	674.15/121.91	729.41/131.90
By-products				
Heat [GWh/year]	92.73	112.18	139.43	158.87
Oxygen [kton/year]	27.39	27.39	27.39	27.39
Biochar [kton/year]	*	12.31	*	12.31
Pyrolysis Oil [kton/year] *-not sold-*	*	6.33	*	6.33

Inspecting the results in *Table* 28, one can observe that after the sale of by-products, Scenario 3 remains the cheapest option for methanol production at 189.87 €/MWh and the order is kept as in the standard cost analysis. The production cost reduction for the different scenarios when selling the mentioned by-products ranges from 3.5%-7% ca.

In this analysis, the sale of the by-products 'heat', 'oxygen', and 'biochar' was considered at the values mentioned previously, sourced from the literature. The sale of pyrolysis bio-oil was not taken into account in this investigation. Usually, pyrolysis bio-oil needs further processing in order to be converted to other products, or even be sold. These approaches were considered to be out of the scope of this research. The effect of selling or further using pyrolysis bio-oil for methanol production is anticipated to have low significance in the obtained results.

4.2.1.2 Assessment of the availability of water resources

A water resource assessment for the small-scale methanol production was also conducted, similarly to Phase 1. This assessment is essential to ensure the viability and sustainability of the methanol production process, particularly regarding the availability and utilization of water resources. 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 conditions of 'maximum water demand' conditions. To provide an accurate representation, the water demand was evaluated on a monthly basis throughout the year. The most demanding scheme in terms of water usage is a combination of Scenario 3 and Scenario 4 (depending on the month), which requires approximately 72110 m^3 of water annually for methanol production. This approach ensures that the water supply would be adequate under the other studied scenarios as well.
Given the findings from the large-scale PtX investigation, where the wastewater resources on Bornholm were sufficient to meet the demands of hydrogen and ammonia production, it is expected that these

resources will also be adequate for smaller-scale methanol production. However, a thorough analysis is still necessary to confirm this assumption and to ensure that the water supply remains sustainable under all the studied operational conditions.

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 *Table* 53 found in *Section* 7.3 of the *Appendix*.

Table 55 in *Section* 7.3 of the *Appendix* outlines the monthly water requirements for the 'maximum water demand' scheme, corresponding to a mix of Scenario 3 and Scenario 4, throughout the year.

To visually compare the water availability from Bornholm's wastewater treatment plants with the methanol plant's maximum water demand, *Figure* 22 presents a graph illustrating these aspects. The graph displays the monthly wastewater output from various Bornholm plants in 2021 (*Table* 53 in the *Appendix*) using distinct bars for each plant. On top of this, the graph includes a black line representing the highest water demand (*Table* 55 in the *Appendix*). Additionally, a dotted red line depicts a hypothetical scenario where this demand is doubled, offering an insight into possible future challenges and demand increases for the water supply system.

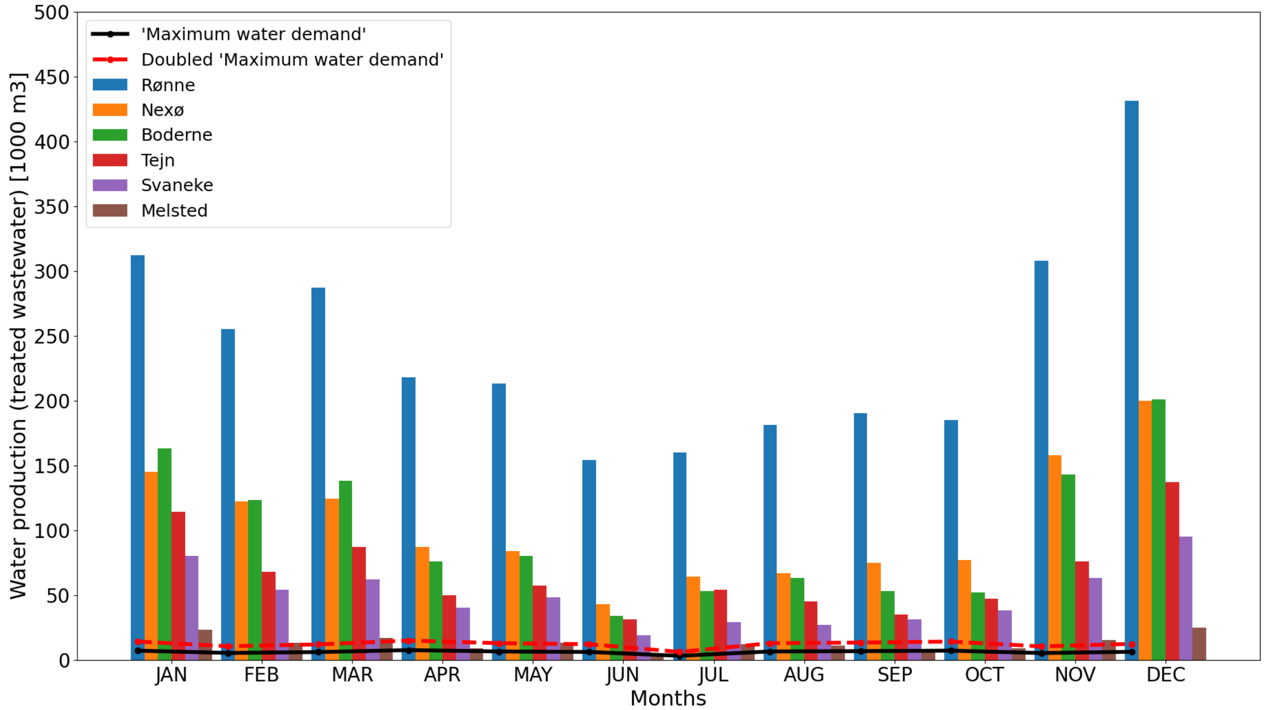

Figure 22: Monthly wastewater production from different treatment plants in Bornholm for 2021 compared with the 'maximum water demand' of the PtX MeOH plant (black line) and a hypothetical 'doubled maximum water demand' scenario (dashed red line).

As previously anticipated, the comparison between the monthly wastewater output from various Bornholm plants in 2021 (*Table* 53 in the *Appendix*) and the 'maximum water demand' corresponding to a mix of Scenario 3 and Scenario 4 (*Table* 55 in the *Appendix*), clearly confirms that all wastewater treatment plants in Bornholm can sufficiently meet the water requirements for methanol production. Moreover, even in a hypothetical scenario where this demand is doubled, most of the treatment plants in Bornholm would still be capable of fulfilling the increased water needs, indicating a robust capacity for potential future expansions in water demand for the methanol production process. This opens up the possibility of decentralizing the production of methanol in Bornholm.

4.2.1.3 Assessment of heat integration from the small-scale PtX plant into DH

This section evaluates the feasibility and impact of integrating the excess heat from the small-scale methanol production process into Bornholm's district heating system. The analysis focuses not only on the effective use of the heat but also on quantifying how much of Bornholm's heat demand could be met by the excess heat. By integrating the excess heat into the district heating network, the overall energy efficiency of the PtX plant could be significantly enhanced, potentially reducing the costs associated with methanol production. Additionally, this integration is crucial for determining the proportion of the island's heating needs that can be sustainably fulfilled through this process, contributing to Bornholm's broader energy sustainability and self-sufficiency objectives. It is important to note that the assumed usage of the biomass resources on Bornholm, see *Table* 21, include 88.5 kton of straw for biogas. 40 kton of the straw is currently used to power the district heating of Bornholm, why an effective heat integration of the PtX-plant is necessary if the straw is to be available for the proposed MeOH production scenarios.

It is important to highlight that the exact temperature details for the excess heat from the PtX plant's processes are not known. This uncertainty can lead to variations in the cost of adapting this heat for district heating use. As a result, while integrating excess heat is a promising idea for improving sustainability and helping Bornholm achieve energy self-sufficiency, a more detailed analysis of its economic and technical feasibility is needed.

At the moment, Bornholm's district heating system requirements are met by seven heat-producing sources spread across the island, supplying approximately 336 GWh of heat annually (see *Figure* 26 in *Section* 7.4 of the *Appendix*).

For a more realistic and accurate representation of Bornholm's heat demand patterns, this study evaluated the demand on a monthly basis throughout the year. The data for the monthly heat quantities produced by these sources in Bornholm was sourced from BEOF and WP4. To mirror real-world operations, the heat demand dynamics of all sources were modelled based on the patterns observed at the Nexø heat plant. This monthly heat supply data for each plant is detailed in *Table* 56 in *Section* 7.4 of the *Appendix*.

Table 58 in *Section* 7.4 of the *Appendix* outlines the excess heat produced in the methanol synthesis for each of the 4 small-scale scenarios, throughout the year.

To illustrate the comparison between the heat supplied to the district heating system by the seven heat-producing facilities in Bornholm and the potential heat output from various methanol production scenarios, *Figure* 23 provides a graph that clearly illustrates these aspects. The graph displays the monthly heat production from all of Bornholm's heat plants in 2021 (*Table* 56 in the *Appendix*) using distinct bars for each individual plant. On top of this, the graph includes lines representing the potential excess heat generated from the MeOH production scenarios (*Table* 58 in the *Appendix*).

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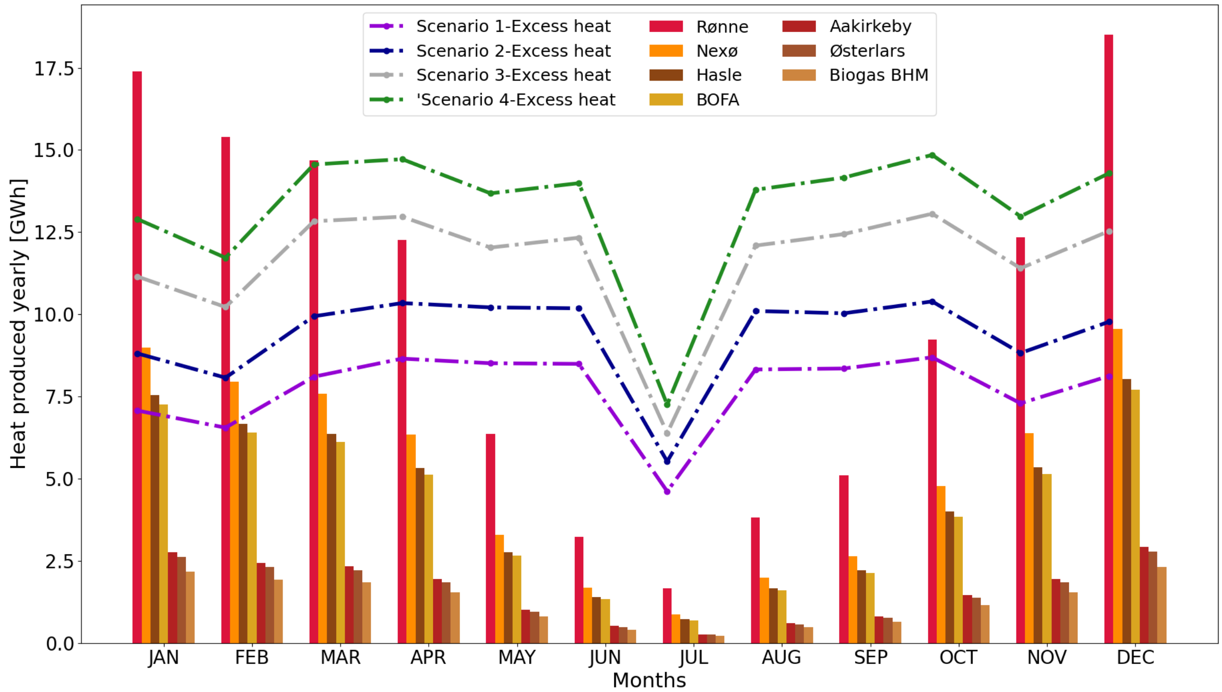

Figure 23: Monthly heat production from different heat plants in Bornholm for 2021 (bars) compared with the potential excess heat from the methanol production scenarios (lines) .

As observed in *Figure* 23, the potential excess heat provided by the methanol production scenarios could totally change the heat production scene in Bornholm. All scenarios are projected to generate more heat than Hasle, which is currently the third-largest heat production facility on the island. Notably, Scenario 4's potential excess heat output approaches that of Rønne, the largest existing facility, in most months of the year. It is important to note that the heat production pattern across these scenarios is characterized by its consistency throughout the year, which is out of sync with the heat demand. This uniformity is only interrupted in July, which is used as a maintenance/shutdown period for the PtX plant in the model. In order to supply enough heat for Rønne during the winter months, another heat source or a large heat storage would however be required. However, as noted earlier, the precise temperatures of the excess heat from the PtX plants are not accurately known. This lack of precision creates uncertainty in the costs involved in modifying this heat for the district heating system's needs. Consequently, integrating this excess heat into Bornholm's heating framework calls for a more comprehensive economic and technical evaluation.

4.2.1.4 Sensitivity analyses on the small-scale methanol plant

In this section, sensitivity analyses on critical assumptions for the small-scale methanol plant are conducted, with a focus on those with the greatest degree of uncertainty. The base case for this comparison comprises the methanol production pathways detailed in *Section* 4.1.2. The scenarios examined in the main part of Phase 2 are derived from these pathways, hence the insights gained from this sensitivity analysis are largely applicable to the scenario outcomes as well.

Five critical factors were analyzed: the offshore wind farm CAPEX, the MeOH production plant CAPEX, the biogenic carbon feedstock price, the PV solar park capacity limit, and the type of hydrogen storage used. The benchmark for these factors and the applied sensitivities in each case are detailed on the following page.

- Offshore Wind Farm CAPEX: In all the model runs (pathways and scenarios), the model chose to use the turbine SP379-HH150 in the OWF. The characteristics of this turbine can be found in *Table* 34 in *Section* 7.1 of the *Appendix*. The CAPEX for this model is 2297 €/kW, and this value was used as the benchmark for all the model runs in this report. Given that the offshore wind farm represents the third largest cost component of the methanol PtX plants in the investigated scenarios, as indicated previously in *Figure* 20 and *Table* 25 from *Section* 4.2.1, this analysis evaluated the impact of varying the CAPEX to 75% and 125% of the benchmark value into the final MeOH production cost.

- MeOH synthesis plant CAPEX: The base case analysis for methanol production pathways utilized different units within the methanol synthesis plant depending on the specific biogenic carbon input. The components modelled for the methanol synthesis plant across the pathways are detailed in *Table* 19 in *Section* 4.1.2. The CAPEX for the entire methanol production plant (including all the units in each case) is 23670 €/kg_{MeOH} for Pathway 1, 30770 €/kg_{MeOH} for Pathway 2, and 40000 €/kg_{MeOH} for Pathway 3 - for MeOH plants with output capacity of 6.7 $kg_{MeOH/h}$. After the scaling factor (simulating economical benefits from economy of scale) is applied in each pathway, the CAPEX of each MeOH plant is 28567 €/kg_{MeOH} for Pathway 1, 27476 €/kg_{MeOH} for Pathway 2, and 42085 €/kg_{MeOH} for Pathway 3. As the methanol synthesis plant represents the largest cost element in the PtX plant study scenarios, as depicted in *Figure* 20 and *Table* 25 from *Section* 4.2.1, this analysis evaluated the effect of varying the CAPEX to 75% and 125% of the benchmark value into the final MeOH production cost.

- Feedstock (biogenic C input) price: Each methanol production pathway evaluated in the base case analysis uses a distinct source of biogenic carbon, with respective costs as follows: 0.131 €/kg of CO_2 in Pathway 1, 0.404 €/kg of biogas in Pathway 2, and 0.089 €/kg of biomass in Pathway 3 (see *Table* 20). From the results displayed in *Figure* 20 and *Table* 25 from *Section* 4.2.1, these feedstock prices have been identified as the second most significant cost driver in the overall methanol PtX system. The sensitivity of the methanol production cost to changes in feedstock prices was therefore examined, assessing the impact of a 50% decrease and 50% increase from the benchmark feedstock prices. This analysis is crucial since the cost of biogenic carbon sources can vary significantly with market fluctuations and availability.

- PV park capacity limit: According to WP1, Bornholm is projected to have 30-40 MWp of solar parks available for Power-to-X (PtX) purposes. In the current investigation, the solar power installation capacity was capped at 40 MWp for all the studied pathways and scenarios. This capacity can play a crucial role in determining the methanol production price as this power generation technology is way cheaper than offshore wind. This sensitivity analysis assessed the effects of modifying the capacity limit to 20 MWp and 60 MWp, representing a reduction and expansion of the solar park capacity, respectively.

- Intermediary hydrogen storage: In the base case investigation of the methanol production pathways, the model chose that the best hydrogen storage system was the buried pipes. Even though this technology is described in the assumptions as better in techno-economic terms, it is not as mature nor easy to implement as using overground hydrogen tanks. Because of that the sensitivity analysis explored the options of using overground hydrogen tanks for hydrogen and observing the effect this has on the methanol production costs.

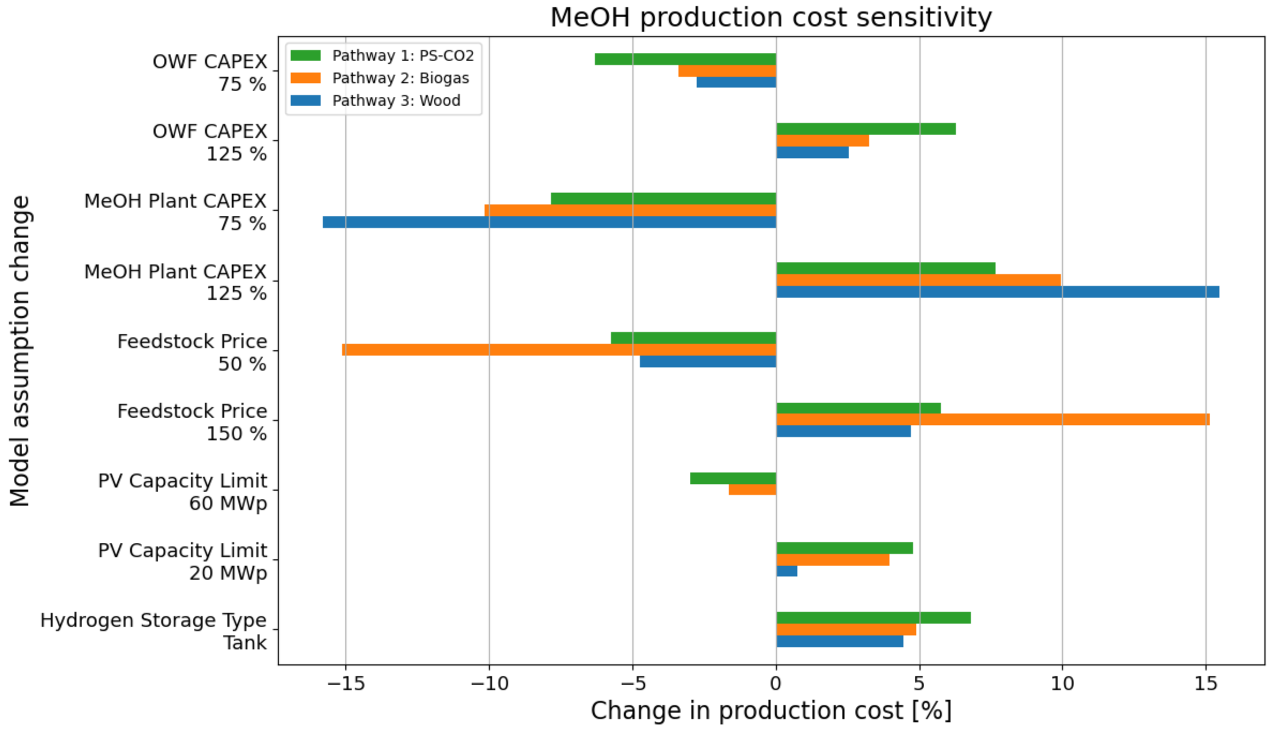

Figure 24: Sensitivity of MeOH production cost to key model assumptions.

- **Offshore wind farm capital investment costs:** This parameter is estimated at 2297 €/kW for the year 2030 for the wind turbine chosen by the model among the 4 available offshore wind turbine types. The price of installation of offshore wind turbines, however, is highly impacted by the discount rate estimated and supply lines. Due to this uncertainty of market conditions it is relevant to do a sensitivity of the LCOM when impacted by varying capital costs for the associated power production. The sensitivity is examined based on a variation of wind turbine capital costs of ±25%. From *Figure* 24, it can be seen that the pathway most sensitive to the wind turbine cost uncertainties is Pathway 1 at ±6% as it also has the highest overall energy need in its process. The sensitivities to this cost uncertainty are generally not very large.

- **MeOH plant cost uncertainties:** The sensitivity of the LCOM to the CAPEX related to the methanol production units is largest for Pathway 3, with a ±16% LCOM to the price uncertainty of ±25% modelled. This can be explained by the fact that the cheap input biomass as well as the relatively small electrolyzer, leave the methanol plant with its gasification process as one of the main cost drivers of the overall production process. Given an opportunity to scale the plant and realize economies of scale for each of these plants, this cost reduction in the methanol plant could be realized. For the pathways, this could be achieved by importing large amounts of carbon from elsewhere - in the form of either biomass, biogas, or CO_2 - Pathway 3 is the option, which would benefit the most from this option, whereas Pathway 1 will benefit the least. Additionally, the carbon transport in the form of CO_2 might be the most costly per kg of carbon compared to the other carbon sources, which does not suggest that this would be a convincing reason to start importing more CO_2 rather than biomass. Since this study focuses on the methanol production potential using biogenic carbon resources on Bornholm, this is not addressed further.

- **Feedstock price:** The sensitivity to the input feedstock price is most significant for Pathway 2 with a ±15% production cost change affected by a ±50% feedstock price variation. The biogas procurement costs were also defined as one of the main cost drivers of Pathway 2 in *Section* 4.1.2, which explains this sensitivity. The feedstock prices for all three pathways are highly uncertain due to the nature of the developing carbon credit market.

Currently, the value addition of the carbon tax to the biogenic carbon sources has not been added to the procurement prices under the assumption that whatever extra value the feedstock resource has will be inherited by the produced e-biomethanol.

- **Solar power availability:** The pathways and scenarios have generally shown that it is desirable to allocate as much solar capacity as possible to methanol production. The capacity was limited to 40 MWp of PV installations as WP1 identified that 30-40 MWp was the allocated capacity in the municipal strategy regarding PV installations designated for PtX-plants on Bornholm. The impact of limiting the capacity more/less is identified through sensitivity analysis of this parameter in the model. This shows that the cost decrease related to allowing 60 MWp PV installations instead of 40 MWp is small at 3% for Pathway 1 and 2% for Pathway 2. However, limiting this investment opportunity even further to 20 MWp results in cost increases of 4-5%. Pathway 3 is generally not sensitive to this parameter but is impacted slightly by further limitations to the installed capacity.

- **Type of hydrogen storage:** Given the techno-economic assumptions regarding above-ground hydrogen tanks vs. underground hydrogen pipes, presented in *Tables* 46 and 47 in *Section* 7.1 of the *Appendix*, the buried hydrogen pipes are consistently invested in by the model. This is mainly due to both the CAPEX and OPEX being lower for the buried pipes. However, given the uncertainty of whether one technology or the other will be feasible for the given business case, the sensitivity analysis of limiting the model to only be able to choose hydrogen tank storage as an intermediary storage option has been performed. The three pathways show similar sensitivity to this limitation by a 5% production cost increase. The sensitivity of the model to intermediary storage of hydrogen is at the same time also heavily influenced by the flexibility of the different plant components as analyzed during the sensitivity analysis of Phase 1. This is not investigated here, but the conclusion that the sensitivity to storage options depends on the flexibility of the plant is generalisable. The more flexible the plant is, the less storage is needed.

4.2.1.5 Methanol production on Bornholm in competition with other locations

This section, much like the analysis in *Section* 3.2.1.6 from Phase 1, examines the feasibility of producing methanol in Bornholm compared to other global locations, using a typical/average weather year (2020) as a reference. We consider four potential methanol production sites: Dakhla (Morocco), Arica (Chile), Ceduna (Australia), and Bornholm (Denmark). Due to social and economic factors, Bornholm is restricted to using offshore wind power and a maximum of 40 MWp of solar, while the other locations can invest in both offshore and onshore wind farms, as well as solar parks unlimitedly.

As done in *Section* 3.2.1.6 from Phase 1 and following Nayak-luke and Bañares-Alcántara (2020) [26], the following discount rates are applied to each country: 7.53% for Denmark, 9.34% for Morocco, 8.20% for Chile, and 7.49% for Australia. All other cost metrics remain the same across these locations.

To sum up, the assumptions associated with the four diverse locations vary in terms of renewable energy sources, power generation capabilities, and discount rates for 2030. However, this analysis does not include socioeconomic factors like labour costs, infrastructure, political stability, or regulatory frameworks, all of which can greatly influence the overall feasibility and appeal of each location for methanol production investments.

This comparative analysis employs exclusively the SOEC technology. The potential sale of by-products (heat, oxygen, and biochar) in the methanol production process in Denmark is also taken into account to make its production costs more competitive. Furthermore, the methanol plant used for this comparison corresponds to the one with the best cost metrics on Bornholm (Scenario 3), which produces 121.9 kton/yr MeOH based on locally sourced biogenic carbon.

On top of that, it is assumed that the methanol plants in Morocco, Chile and Australia used in this comparison have a production capacity of 600 kton/yr. These plants are presumed to utilize Direct Air Capture (DAC) as their input carbon source (as described in Pathway 4), a typical method for large-scale MeOH plants projected for 2030 [40], since large amounts of biogenic biomass might not be available in these locations.

The resulting methanol production costs for the comparison study described above can be seen in *Table* 29 below:

Table 29: Fuel production for the PtX methanol plants in various locations for a typical/average weather year (2020). Demand settled at 121.9 kton/yr using biomass for Bornholm (Scenario 3) and 600 kton/yr using DAC for the rest of the locations (Pathway 4).

	Morocco	**Chile**	**Australia**	**Bornholm**
MeOH fuel production cost [€/MWh]/[€/kg]				
Standard	188.05/1.04	192.62/1.06	200.91/1.11	196.71/1.09
By-product sale *-DK only-*	*	*	*	189.87/1.05

According to the data presented in *Table* 29, Morocco stands out as the most cost-effective location for methanol production, with a production cost of 1.04 €/kg. In comparison, Chile and Australia exhibit slightly higher methanol production costs, at 1.06 €/kg and 1.11 €/kg respectively. However, Bornholm demonstrates competitive pricing in methanol production, with costs at 1.09 €/kg and a reduced 1.05 €/kg when taking into account the revenue from by-product sales.

Despite Morocco, Chile, and Australia having better combined meteorological conditions for both solar and wind power, Bornholm's e-biomethanol production remains competitive. This is notable considering Bornholm's limitations to offshore wind investment and a 40 MWp cap on solar capacity, while the other locations can freely invest in both onshore wind and unrestricted solar capacities. Bornholm's e-biomethanol production not only can compete with significantly larger DAC-fueled e-methanol plants in Morocco but also outperforms those in Chile and Australia (with and without the by-product sale revenue).

4.2.2 Conclusions from the deterministic analyses (MeOH)

The deterministic evaluation of small-scale Power-to-X plants, utilizing weather data from an average weather year and SOEC-based PtX plants for 2030, has yielded valuable insights into several critical aspects such as plant sizing, cost implications, and other vital considerations. Key conclusions from this analysis include:

• **MeOH Pathways-Fuel production costs:** The comprehensive analysis of the four proposed methanol production pathways reveals notable differences in both the costs and quantities of fuel produced. Pathway 3 (MeOH from wood) emerges as the most cost-effective option, with a production cost of 199.08 €/MWh (1.10 €/kg) and a yield of 46.64 $kton_{MeOH}$/y (using Bornholm's biogenic carbon). On the other hand, Pathway 4 (MeOH from DAC CO2) is the most expensive at 306.84 €/MWh (1.70 €/kg) but offers the greatest potential for methanol production, 254.73 $kton_{MeOH}$/y, mainly due to the unlimited availability of atmospheric CO2 as a carbon source. However, the DAC technology lacks full maturity and requires significant land use. Using DAC CO2 is currently not a competitive option for methanol production, even when considering economies of scale and all the available 800MW overplanting from the OWF. Pathway 1 (MeOH from PS-CO2) incurs production costs of 1.56 €/kg and a yield of 31.24 $kton_{MeOH}$/y and Pathway 2 (MeOH from biogas) has a production cost of 1.14 €/kg and a potential production 75.27 $kton_{MeOH}$/y.

• **MeOH Scenarios-Fuel production costs:** Four distinct scenarios were developed to investigate the possibilities for methanol production, each combining the previously outlined production pathways and progressively utilizing a greater amount of Bornholm's available biogenic carbon. Two approaches were used when examining the fuel production costs of the methanol scenarios: a standard cost analysis and a cost analysis considering by-product sales.

In the standard cost analysis, Scenario 3 is the cheapest option for producing methanol at 196.71 €/MWh, and Scenario 2 is the most expensive at 214.28 €/MWh, showing an 8.93% cost difference. The amount of methanol produced is lowest in Scenario 1 at 75.27 kton/year and highest in Scenario 4 at 131.90 kton/year. Including slow pyrolysis of biogas digestate in Scenario 2 results in an extra 55.3 GWh/year of methanol and increases costs by 8.09 €/MWh compared to Scenario 1. In Scenarios 3 and 4, adding this pyrolysis to Scenario 4 also raises production by 55.3 GWh/year but only increases the cost by 5.64 €/MWh compared to Scenario 3. In the cost analysis that includes by-product sales (heat, oxygen and biochar), Scenario 3 stays as the most affordable method for methanol production at 189.87 €/MWh, maintaining the same cost ranking as in the standard analysis. The reduction in production costs for the different scenarios due to by-product sales is 4.40% for Scenario 1, 7.17% for Scenario 2, 3.47% for Scenario 3, and 5.27% for Scenario 4.

• **Major cost components of the MeOH plants:** For the small-scale PtX plant sizing, the model is driven by the available biogenic carbon available in Bornholm. In all scenarios, the largest cost factor is consistently the methanol synthesis reactor, mainly due to the high cost of the catalyst used. Following this, the procurement of biogenic carbon sources, especially biogas priced at 0.404 €/kg, emerges as the second major expense. The offshore wind farm (OWF) ranks as the third significant cost component. Breaking down the overall cost distribution, the methanol synthesis reactor accounts for 30%-40% of the total costs across different scenarios. The biogenic carbon sources contribute to about 20%-30% of the costs, while the offshore wind farm represents approximately 15%-20%.

• **Water resources availability:** The assessment of water resources shows that Bornholm's wastewater treatment plants can easily meet the maximum water needs for methanol production (represented as a combination of Scenario 3 and Scenario 4). Even if this maximum water demand was doubled, most treatment plants on the island could still handle the increased need. This suggests that Bornholm has a strong capacity to expand its water use for methanol production, potentially allowing for methanol production to be spread out across different locations on the island.

• **Excess heat production and DH integration:** An analysis of the excess heat from the PtX reveals that all scenarios produce more heat than the Hasle facility, which is currently the third-largest heat source on Bornholm. Particularly, Scenario 4 generates excess heat close to Rønne, the island's largest facility, in most months. However, to meet Rønne's winter heating demands, an additional heat source or substantial heat storage would be needed. It's also important to remember that the exact temperatures of the excess heat from the PtX plants are not well-defined, leading to uncertainties in the cost of adapting this heat for the district heating system. Therefore, using this excess heat in Bornholm's heating network requires further detailed economic and technical analysis.

• **Sensitivity analyses:** The sensitivity analyses focused on the effect on the fuel production costs in the MeOH production pathways when changing the offshore wind farm CAPEX (x0.75-x1.25), the MeOH production plant CAPEX (x0.75-x1.25), the biogenic carbon feedstock price (x0.5-x1.5), the PV solar park capacity limit (20MWp-60MWp), and the type of hydrogen storage used (buried pipes vs tanks). The cost of producing MeOH was particularly sensitive to changes in the MeOH plant CAPEX and the cost of feedstock, with Pathway 3 and Pathway 2 experiencing cost variations of -15% to +15%. Fuel costs remained relatively stable with changes in PV capacity and OWF CAPEX, though Pathway 1 saw the most impact, with up to a +5% cost increase. All three evaluated pathways were similarly affected when replacing the option of underground pipes for intermediate hydrogen storage with hydrogen tanks, leading to a cost increase of approximately 5%.

- **Methanol production competition with other locations:** The study evaluated methanol production costs at SOEC-PtX plants in various global locations, considering available renewable energy sources, power generation profiles, and discount rates for 2030, but not including socioeconomic factors. For this comparison, the chosen methanol plant in Bornholm (Scenario 3), which produces 121.9 kton/yr of MeOH using local biogenic carbon, had the best cost metrics. The methanol plants in Morocco, Chile, and Australia, with a capacity of 600 kton/yr each, are assumed to use Direct Air Capture (DAC) for carbon sourcing. Morocco emerged as the most cost-effective location at 1.04 €/kg, while Chile and Australia had slightly higher costs at 1.06 €/kg and 1.11 €/kg, respectively. Bornholm's methanol production costs are competitive at 1.09 €/kg, dropping to 1.05 €/kg with by-product sales revenue. Despite its geographical limitations, Bornholm's e-biomethanol production is still competitive against larger DAC-fueled plants in Morocco and even surpasses those in Chile and Australia, both with and without by-product sales.

5 Overall WP2 Conclusions

This report focuses on the detailed exploration and modelling of scenarios for Power-to-X and alternative fuels production in Bornholm, conducted under Work Package 2 (WP2). The investigations and analyses undertaken in this project offer key insights into the current state and future prospects of sustainable energy solutions, tailored to Bornholm's unique context and its potential influence beyond.

The central question addressed by WP2 revolved around the feasibility of establishing a Power-to-X (PtX) plant in Bornholm by 2030, using renewable energy and local resources. Phase 1 of the analysis primarily explored the potential for large-scale hydrogen and ammonia production, predominantly using offshore wind energy. Following this, Phase 2 shifted focus to a more localized approach, examining the viability of a smaller-scale methanol plant. This phase particularly concentrated on the utilization of local biogenic carbon sources for methanol production.

Phase 1 investigated large-scale **hydrogen** production in Bornholm and identified SOEC as the most cost-effective electrolyser technology for a behind-the-meter PtX plant, resulting in 11% cheaper fuel costs than AEC. The SOEC approach yields a fuel production cost of €4.05/kg in a typical weather year, which can be further reduced to €3.65/kg with the sale of by-products such as oxygen and heat. The oxygen is sold at 0.05 €/kg and the heat at 20 €/MWh. Both by-products are assumed to be sold constantly over the year (no seasonality). The oxygen revenue is approximately 4 times bigger than the heat one. In terms of cost distribution, the offshore wind farm (OWF) emerges as the primary expense, accounting for approximately 63% of the total costs, while the electrolyzer contributes around 36%. This highlights significant potential for cost reductions in these areas. Moreover, exploring the possibility of shipping hydrogen to Germany, the study estimated transport costs at approximately €0.60/kg per 1000 km. Using this estimate the levelized costs of hydrogen transport to Germany would be 0.6 €/kg and 1.8 €/kg for Bornholm and Dakhla (Morocco) respectively. This results in final market prices of hydrogen of 4.6 €/kg for Bornholm and 3.5 €/kg for Morocco.

While the production costs of **hydrogen** on Bornholm in a typical weather year, primarily driven by reliance on offshore wind energy, are marginally higher than the International Energy Agency's (IEA) projections for 2030's Western Europe and exceed those in other locations, Denmark's strategic location and the potential of being first-movers offer certain benefits. Coupled with the growing focus on Europe's security of supply and challenges in terms of public acceptance of onshore wind, large-scale PV plants and electricity transmission, this underscores the justification for exploring hydrogen production in Bornholm. However, these advantages must be carefully balanced against the higher production costs and related challenges. The feasibility and potential competitiveness of H_2-producing PtX plants in Bornholm are possible as there is room for improvement to bring the costs down (e.g. via grid-balancing services, local subsidies...), but the decision to invest must consider both the economic implications and the strategic opportunities provided by Denmark's location and market dynamics.

The Phase 1 investigation into large-scale **ammonia** production in Bornholm also identified SOEC as the most economical electrolyser technology for a behind-the-meter PtX plant, having 13% cheaper fuel costs than AEC. The SOEC scenario revealed a production cost of €0.91/kg in a typical weather year, which could be reduced to €0.84/kg by incorporating the by-product sales of heat and oxygen. A 50% of the total costs are attributed to the offshore wind farm, with the electrolysis units accounting for another 27%. This cost distribution again suggests a notable potential for cost reductions, particularly in these two key units. In contrast to hydrogen production, ammonia production in Bornholm requires additional investments in storage solutions like batteries and hydrogen storage.

When assessing the competitiveness of **ammonia** production in Bornholm it can be observed that production costs in Bornholm remain competitive and are only marginally higher than the International Energy Agency's (IEA) 2030 projections for Western Europe and locations like Morocco, where more cost-effective energy sources like solar and onshore wind are available. Several factors contribute to Bornholm's potential advantages in ammonia production, including its proximity to key markets like Germany, the Baltic Sea and the opportunity for early market entry.

However, a significant finding of this investigation is that this cost dynamics could change dramatically if Bornholm's **ammonia** plant were to become semi-islanded with grid access. This would align its production costs with those of a Moroccan behind-the-meter plant. Although Bornholm currently faces connectivity challenges, the upcoming plans to link the island to both Zealand and Germany as part of the energy island project hold promise in this regard. Nonetheless, a critical consideration for ammonia production in Bornholm, particularly concerning green certification, is the present high grid emissions. To meet the criteria for certified green ammonia, it is crucial to ensure that the grid power utilized, predominantly originates from renewable electricity generation, aligning with the requirements outlined in the European Renewable Hydrogen Acts. This underscores the necessity for a well-planned and strategic approach to renewable energy integration and grid connectivity to facilitate sustainable ammonia production on the island.

In Phase 1, a comprehensive assessment of resource availability and sector coupling was conducted for both hydrogen (H_2) and ammonia (NH_3) production. This assessment included an analysis of water and land resources and explored the potential integration of excess heat generated by the PtX plants into Bornholm's district heating system.

One notable observation was that the Rønne wastewater treatment plant could comfortably meet the maximum water demand for the examined large-scale PtX plants, ensuring a reliable and robust water resource supply for both H_2 and NH_3 production.

In terms of heat generation, all scenarios (except the SOEC-based ones) are projected to produce similar monthly heat outputs compared to the combined capacity of the island's existing seven heat production facilities. It's worth noting that the precise temperatures of the excess heat from the PtX plants are not precisely determined, introducing uncertainty regarding the cost implications of adapting this heat for integration into the district heating system. Therefore, the successful integration of this excess heat into Bornholm's heating framework would necessitate a more in-depth examination, considering both economic and technical factors.

Regarding land availability, there is land to accommodate these PtX scenarios, with the maximum required area being 43.8 Ha for the NH_3-SOEC scenario. For reference a transformer sub-station usually occupies 107 Ha.

Phase 2 investigated small-scale **methanol** production in Bornholm, taking into account four potential methanol production pathways that utilize the island's biogenic carbon resources. These pathways varied in production costs and quantities. Pathway 3 (MeOH from wood) emerged as the most cost-effective choice, with a production cost of 199.08 €/MWh (1.10 €/kg) and a yield of 46.64 $kton_{MeOH}$/year. In contrast, Pathway 4 (MeOH from DAC) was the most expensive, with a cost of 306.84 €/MWh (1.70 €/kg). However, it offered the highest methanol production potential at 254.73 $kton_{MeOH}$/year due to an abundant source of atmospheric CO2. Nonetheless, the immature state of DAC technology and significant land requirements currently make this approach non-competitive for methanol production on the island.

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Next, four different scenarios were developed to explore the possibilities for **methanol** production in Bornholm for a typical weather year, combining the previously studied production pathways and progressively utilizing a greater amount of Bornholm's available biogenic carbon. In the standard cost analysis, Scenario 3 [biogas reforming + two-stage wood gasification] proved to be the most cost-effective for methanol production at 196.71 €/MWh, while Scenario 2 [biogas reforming + pyrolysis of digestate] emerged as the most expensive at 214.28 €/MWh, representing an 8.93% cost difference. Scenario 4 [biogas reforming + two-stage wood gasification + pyrolysis of digestate] produced the highest amount of methanol at 131.90 kton/year, while Scenario 1 [biogas reforming] yielded the lowest at 75.27 kton/year. In the cost analysis with by-product sales, heat was sold at 20 €/MWh, oxygen at 0.05 €/kg, and biochar at 0.26 €/kg. All by-products are assumed to be sold constantly over the year (no seasonality). Scenario 3 remained the most cost-effective method for methanol production at 189.87 €/MWh, maintaining the same cost ranking as in the standard analysis (no by-product sale). The introduction of by-product sales reduced production costs for the different scenarios by around 3-7%.

In all scenarios, the most significant cost factor is the methanol synthesis reactor, primarily due to the high-cost catalyst. Procuring biogenic carbon sources is based on the assumptions the second major expense. The offshore wind farm (OWF) is the third significant cost component. The breakdown of overall cost distribution shows that the methanol synthesis reactor accounts for 30%-40% of total costs, biogenic carbon sources contribute to about 20%-30%, and the OWF represents approximately 15%-20%

The comparative analysis of **methanol** production costs among global SOEC-PtX plants considered factors like renewable energy sources, power profiles, and 2030 discount rates, with socioeconomic factors such as labour costs, infrastructure, political stability, or regulatory frameworks excluded. Bornholm's selected methanol plant (Scenario 3), producing 121.9 kton/yr using local biogenic carbon, showed favourable cost performance. In contrast, large-scale methanol plants in Morocco, Chile, and Australia, with a 600 kton/yr capacity and utilizing Direct Air Capture (DAC) for carbon, displayed varying cost structures. Morocco emerged as the most cost-effective at 1.04 €/kg, while Chile and Australia had slightly higher costs at 1.06 €/kg and 1.11 €/kg, respectively. Bornholm's methanol production costs remained competitive at 1.09 €/kg, dropping to 1.05 €/kg with by-product sales. Notably, Bornholm's e-biomethanol production held its own against larger DAC-fueled plants in Morocco, surpassing those in Chile and Australia in terms of cost-effectiveness, regardless of by-product sales.

In Phase 2, a comprehensive evaluation of resource availability and sector integration was carried out for small-scale methanol production in Bornholm. This assessment included an examination of the availability of water resources and investigated the feasibility of integrating the excess heat generated by the PtX plant into Bornholm's district heating system.

The assessment of water resources revealed that Bornholm's wastewater treatment facilities have the capacity to comfortably fulfil the maximum water requirements for methanol production, even if those demands were to double

The excess heat from the methanol PtX plants in all scenarios surpasses the Hasle facility, Bornholm's third-largest heat source. Scenario 4 even generates excess heat close to Rønne, the island's largest facility, for most months. However, ensuring enough heat for Rønne's winter needs would require additional heat sources or substantial heat storage. The uncertain heat temperatures make it necessary to conduct further economic and technical analysis for the excess integration into the district heating system.

6 Recommendations

Work Package 2 (WP2), focusing on the modelling 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.

In Phase 1 of WP2, a thorough examination of the feasibility and implications of large-scale hydrogen and ammonia production in Bornholm was conducted. The primary objective was to meet the energy needs of the island while also considering the potential for Bornholm to become a hub for hydrogen and ammonia production in the maritime sector, contributing to regional environmental sustainability. Phase 2 directed its focus towards the feasibility of small-scale methanol production in Bornholm. This phase explored different pathways for sustainable energy solutions by assessing the feasibility and implications of producing methanol on a smaller scale using local biogenic carbon sources. The aim was to assess the potential of producing methanol using the island's biogenic carbon sources, to meet a substantial portion of the local energy and fuel demand. The tasks and objectives set for both Phase 1 and Phase 2 were successfully accomplished, establishing a robust foundation for future initiatives in sustainable energy projects on the island.

The current project has provided a first assessment of the feasibility of different types of PtX plants on Bornholm. A recommended next step would be a market analysis assessing the potential sales price followed by a private economic feasibility study taking into account potential subsidies, taxes and tariffs for a specific plant with a determined location.

Based on the results of the analyses it is recommended to further explore the possibility of having **semi-islanded operation**, with the possibility to use electricity from the grid to supplement the electricity from the offshore wind power and the PV plant. It should however be ensured that the produced fuel can still be certified as green. Furthermore, it would be interesting to explore the potential of providing balancing services to the grid with flexible operation. The local potential for improving the market for **sales of by-products**, in particular oxygen, should also be explored. Finally, possible **first-mover advantages** should be investigated as these could make particularly hydrogen export to Germany competitive.

It is the intention of the DTU Management research team to further investigate the outcomes and insights gained from this thorough investigation 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 modelling.

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7 Appendix

7.1 Techno-economical input data for 2030 of the PtX plant units

This section contains the complete 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 the OptiPlant model. 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.

Table 30: Input technological assumptions for 2030 used in the model for the large-scale PtX plant study

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 CCU	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[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 (or kW)	0.1[6]	0	49.8[4]
Electrolyser Park SOEC heat integrated	H_2O/H_2	kg_{H_2}/h (or kW)	0.1[6]	0	37.9[7]
Electrolyser Park SOEC alone	H_2O/H_2	kg_{H_2}/h (or kW)	0.1[6]	0	43.2[4]
Electrolyser Park 75AEC-25SOEC$_{HI}$	H_2O/H_2	kg_{H_2}/h (or kW)	0.1[6]	0	46.8
Electrolyser Park 75AEC-25SOEC$_A$	H_2O/H_2	kg_{H_2}/h (or kW)	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	$\text{Bio-oil}_{in}/\text{Bio-oil}_{out}$	$kg_{Bio\text{-}oil}$	0	0	-[13]

[1] Based on [35].
[2] Based on [34].
[3] At 100 bars and 220°C, based on [51]. [6] refers to the value 1.7 kWh/output.
[4] Based on [6].
[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 Campion2023 (assuming that heat integration performances will be similar as of 2020).
[8] Based on [8].
[9] Based on [9] assuming same values as of 2020.
[10] Based on communication with industrial partners.
[11] Based on [3].
[12] Based on [52], 0.014 kilograms of H_2 per kilogram of bio oil. This was obtained from experimental work .
[13] Based on [52], electrical consumption is included in the OPEX expenses.

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Table 31: Input economical assumptions for 2030 used in the model for the large-scale PtX plant study

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

[1] For a medium-scale 13.3 t_{MeOH}/h plant capacity based on [41], [35], [42], cost-to-capacity ratio = 0.7. [6] refers to a CAPEX of 17532€ per capacity installed.
[2] 4% Capex based on [6].
[3] For a large-scale 95 t_{NH_3}/h plant capacity based on [6] (includes ASU).
[4] Using the 2025 best value from [7].
[5] 3% Capex based on [7].
[6] Using the 2025 benchmark value based on [7].
[7] From [6].
[8] Using 10% Capex based on [6].
[9] Based on [12].
[10] 8.55% Capex based on [12].
[11] Based on [10] (includes compressors).
[12] 3% Capex based on [10].
[13] Based on [10] for a working pressure around 100 bars.
[14] From [15].
[15] From [10] assuming low lithium price.
[16] 1.5% Capex based on [10].
[17] Based on [3], bio-char as a co-product with 70% carbon. CO2 credits are about 0.10 €per kiogram of CO_2.
[18] Based on [53] and [54], high costs mainly from catalyst costs. OPEX is roughly 20% CAPEX.
[19] Based on [43] and [55], for a reserve of around 28 days at 40°C. OPEX consideres expenses from the heating system.

Table 32: Input technological assumptions for 2030 used in the model for the small-scale PtX plant study

Type of units	Input/Output -	Capacity -	Fuel production rate kg output/kg input	Load min % of max capacity	Electrical consumption kWh_{el}/output	Excess heat > 80^o kWh_{th}/output
MeOH plant - CO2	H_2/MeOH CO_2/MeOH	kg_{MeOH}/h	5.26[1] 0.73[1]	20[2]	0.316[3]	0.68[3]
MeOH plant - Biogas	H_2/MeOH Biogas/MeOH	kg_{MeOH}/h	22.0[1] 1.17[1]	20[2]	1.31[4]	1.23[4]
MeOH plant - Biomass	H_2/MeOH Biomass/MeOH	kg_{MeOH}/h	15.7[1] 0.86[7]	20[2]	0.64[7]	0.43[7]
Wastewater plant	-/H_2O	kg_{H_2O}/h	0	0	0.0025[6]	0
Electrolyser Park AEC	H_2O/H_2	kg_{H_2}/h	0.1[7]	0	49.8[8]	5.68[8]
E.P. SOEC heat integrated	H_2O/H_2	kg_{H_2}/h	0.1[7]	0	37.9[9]	0
E.P. SOEC alone	H_2O/H_2	kg_{H_2}/h	0.1[7]	0	43.2[8]	0
H_2 storage tank	H_{2in}/H_{2out}	kg_{H_2}	0	3[10]	0	0
H_2 storage buried pipes	H_{2in}/H_{2out}	kg_{H_2}	0	9[11]	0	0
Battery Park	kWh_{in}/kWh_{out}	kWh	0	0[12]	0	0
DAC plant	Air/CO_2	kg_{CO_2}/h	-	0	1.7[13]	0
Pyrolysis plant[14]	Digestate/Gas Digestate/Char Digestate/Oil	$kg_{digestate}$/h	0.15 0.18 0.09	0	0.14[15]	0.28[15]

[1] Based on [6] - stoiciometrically defined with 100% conversion of carbon and gases.
[2] Based on [34].
[3] Based on [35].
[4] Based on [36].
[5] Based on [37].
[6] Based on [7].
[7] Consumption of non-purified water assuming a purification efficieny of 80% based on [7].
Conversion of purified water to hydrogen is stoichiometric (9 kg of water consumed per kg of hydrogen).
[8] Based on [6].
[9] From [38] (assuming that heat integration performances will be similar as of 2020).
[10] Based on [8].
[11] Based on [9] assuming same values as of 2020.
[12] Based on communication with industrial partners.
[13] Estimate based on [39] and [6].
[14] Based on [40] - technology catalogue bases its assumptions primarily on Stiesdal's SkyClean project.
[15] The unit is kWh/input.

Table 33: Input economical assumptions for 2030 used in the model for the small-scale PtX plant study

Type of units	Capacity -	Investment €/Capacity	Fixed cost €/Capacity/y	Variable cost €/Output	Lifetime Years
MeOH plant - CO2	kg_{MeOH}/h	23670[1]	947[2]	0	20[3]
MeOH plant - Biogas	kg_{MeOH}/h	30770[4]	1231[2]	0	20[3]
MeOH plant - Biomass	kg_{MeOH}/h	40000[5]	1600[2]	0	20[3]
Waste water plant	kg_{H_2O}/h	107.6[6]	3.2[7]	0	15[8]
Electrolyser Park AEC	kg_{H_2}/h	39840[9]	3984[10]	0	25[3]
E.P. SOEC heat integrated	kg_{H_2}/h	39584[11]	3384.4[12]	0	25[3]
E.P. SOEC alone	kg_{H_2}/h	39584[11]	3384.4[12]	0	25[3]
H_2 storage tank	kg_{H_2}	800[13]	24[14]	0	10[15]
H_2 storage buried pipes	kg_{H_2}	250[16]	7.5[14]	0	50[17]
OFF_SP379-HH100	kW	1998[18]	37.6[18]	0.0028[18]	30[18]
OFF_SP379-HH150	kW	2297[18]	37.6[18]	0.0028[18]	30[18]
OFF_SP450-HH100	kW	1801[18]	37.6[18]	0.0028[18]	30[18]
OFF_SP450-HH150	kW	2053[18]	37.6[18]	0.0028[18]	30[18]
1-axis tracking Solar Park	kWp	458.8[18]	9.28[18]	0[18]	40[18]
Battery Park	kWh	180[19]	2.7[20]	0	25[20]
DAC plant	kg_{CO_2}/h	6000[21]	300[21]	0	20[22]
Pyrolysis plant	$kg_{digestate}/h$	3028[23] OR 3788 from tech. cat.	401[24] OR 327 from tech. cat.	0	25

[1] For a small-scale 6.7 t_{MeOH}/h plant capacity based on [35], [41], [42], validated by [6].
Capital cost scaled by power law - scaling factor ~0.7. [6] refers to a CAPEX of 17532€ per capacity installed
for medium-scale plant of 13.3 t_{MeOH}/h, and 8328€/Capacity for large-scale plant of 133 t_{MeOH}/h.
[2] 4% of capital investment based on [6].
[3] Based on [43].
[4] 130% of capital investment compared to MeOH plant - CO_2. Estimated additional cost of reformer
Based on [44], and assuming similar costs for electrical vs conventional reformers. Both validated by stakeholders.
[5] 130% of capital investment compared to MeOH plant - Biogas. Estimated additional cost of gasifier and gas cleaning units.
Based on [37], validated by stakeholders.
[6] Using the 2025 benchmark value based on [7].
[7] 3% Capex based on [7].
[8] From [7].
[9] From [6]. Corresponds to a CAPEX of 800€/kW_e.
[10] Using 10% Capex based on [6].
[11] Based on [12] and talks with industry partners.
Corresponds to a CAPEX of 1157€/kW_e for a heat integrated SOEC and 916€/kW_e for non-heat integrated SOEC.
[12] 8.55% Capex based on [12].
[13] Based on [10] (includes compressors).
[14] 3% Capex based on [10].
[15] For high-pressure tanks, life span is around 10 years, depending on the frequency of filling/emptying. Based on [13].
[16] Based on [10] for a working pressure around 100 bars.
[17] Based on [14].
[18] From [15].
[19] From [10] assuming low lithium price.
[20] 1.5% Capex based on [10].
[21] Estimates based on [6].
[22] Based on [45].
[23] Based on [3] with plant of 20 MW input biomass.
[24] 13.25% of capital investment based on [3].

7.1.1 Power supply units

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 35. 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.

7.1.1.1 Offshore Wind Farm

Table 34: Offshore wind turbines considered in the model technology catalogue

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

Table 35: Offshore wind farm costs 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
CO_2 emission infrastructure [$kg_{CO2}e$/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

7.1.1.2 Utility-scale Solar PV

Table 36: Fixed-axis solar PV plant. Data includes all conversion losses with AC/DC converter.

Parameter	Units	Worst	Benchmark	Best	2030	2040	2050
Maximum available capacity	kW	-	50,000	-	500,000	-	1,000,000
Investment expenditure	€/kW	552.679	552.679	552.679	396.26	344.1	312.837
Fixed cost	€/kW/year	9.124	9.124	9.124	7.560	6.908	6.517
Variable cost	€/kWh	0	0	0	0	0	0
Life Time	years	35	35	35	40	40	40
Annuity factor	-	0.0858	0.0858	0.0858	0.0839	0.0839	0.0839
CO2 emissions infrastructure	kg_{CO_2}/kWp/year	90.6	90.6	90.6	61.9	33.2	4.5
CO2 emissions process	kg_{CO_2}/kWh	0	0	0	0	0	0
Land use	m^2/kW	13.75	13.75	13.75	12.26	11.51	10.84
Capacity factor in Bornholm	%	13.9	13.9	13.9	13.9	13.9	13.9
LCOE	€/MWh	-	-	-	33.6	-	-

Table 37: 1-axis tracking solar PV plant. Data includes all conversion losses with AC/DC converter.

Parameter	Units	Worst	Benchmark	Best	2030	2040	2050
Maximum available capacity	kW	-	-	-	-	-	-
Investment expenditure	€/kW	761.237	646.530	583.962	458.83	406.7	375.404
Fixed cost	€/kW/year	11.601	11.158	7.691	9.2808	8.551	8.133762
Variable cost	€/kWh	0	0	0	0	0	0
Life Time	years	35	35	35	40	40	40
Annuity factor	-	0.0858	0.0858	0.0858	0.0839	0.0839	0.0839
CO2 emissions infrastructure	kg_{CO_2}/kWp/year	91	91	91	62	33	5
CO2 emissions process	kg_{CO_2}/kWh	0	0	0	0	0	0
Land use	m^2/kW	18	18	18	16	15	14
Capacity factor in Bornholm	%	18.3	18.3	18.3	18.3	18.3	18.3
LCOE	€/MWh	-	-	-	29.9	-	-

7.1.2 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. All the techno-economical aspects of the different technologies are displayed in the *Table* 38. Additionally, the efficiency of the electrolyzers is found to depend on the load, see more in the load curve in Figure 25. 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.

Table 38: Electrolyser Park techno-economic data. Includes 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.

Load Curve AEC:

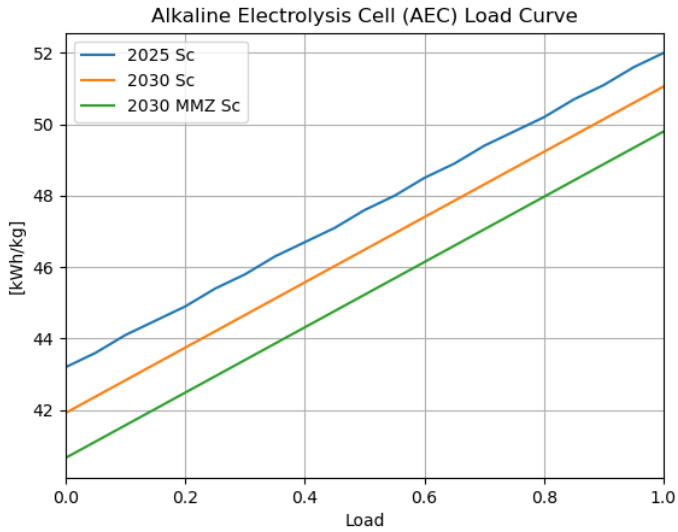

Figure 25: AEC load curve - Electricity consumption of electrolyzer at different loads.

Table 39: Linear regression parameters of the curves in *Figure* 25

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

7.1.3 Ammonia synthesis 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 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. The techno-economic characteristics of the different technologies are displayed in the *Table* 40.

Table 40: 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
CO_2 emissions during process	$kg_{CO2}e$/(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.

7.1.4 Methanol plant. Pyrolysis plant, and DAC

The methanol synthesis in each route is done in a reactor with the catalyst Cu/ZnO/Al2O3. The reaction is exothermic and a source of heat for district heating. The amount of excess heat available varies depending on the route, as the heat integration of the plant and the reactions vary. Each of these pathways needs different technological and operational requirements, and are listed below:

- Pathway 1 - Methanol (MeOH) from point-source CO_2
- Pathway 2 - Methanol (MeOH) from biogas
- Pathway 3 - Methanol (MeOH) from wood
- Pathway 4 - Methanol (MeOH) from DAC CO_2

Each methanol production pathway involves different units/components within the methanol production plant. This is primarily due to the variations in biogenic carbon inputs specific to each pathway. The unique composition of each plant plays a significant role in determining its operational dynamics and overall cost. All the units/components modelled for the methanol plant in each of the pathways are listed in *Table* 41. The purchase price of the different input biogenic C sources for each scenario are gathered in *Table* 42. The technical and economic assumptions used for these units are detailed in *Table* 43 and *Table* 44

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Table 41: Units/components considered in OptiPlant when modelling the methanol plant for each production pathway

MeOH plant units/components	
Pathway 1 (PS CO_2)	Methanol synthesis reactor, distillation towers, and turbomachinery
Pathway 2 (biogas)	Electric reformer, methanol synthesis reactor, distillation towers, and turbomachinery
Pathway 3 (wood)	Drying section, pyrolysis unit, POX, gasifier, gas cleaning unit, methanol synthesis reactor, distillation towers, and turbomachinery
Pathway 4 (DAC CO_2)	Methanol synthesis reactor, distillation towers, and turbomachinery

Note: The slow pyrolysis of digestate was simulated similarly to pathway 3

Table 42: Purchase prices considered in the model for the different biogenic carbon sources used in the methanol production pathways.

Carbon source	**PS-CO_2**	**Biogas**	**Wood (chips and waste)**	**DAC-CO_2**
[€/kg]	0.131[1]	4.04[2]	0.089[3]	*-Cost of DAC plant-*

Note: CO_2 and CH_4 are considered as ideal gases. The biogas is assumed to be 60%CH_4-40%CO_2, with a density of 1.19kg/m^3. The energy content of the biomass is assumed to be 12.5 MJ/kg

[1] Based on estimates from [6] on the cost of separating CO_2 and CH_4 in biogas.

[2] Based on estimated production cost of biogas [46] and estimated green certificate value of biogas [47].

[3] Medium predicted wood chips prices for 2030, based on [48]

Table 43: Technical data for the different types of Methanol plant units considered in the model

Type of units	Input/Output -	Capacity -	Fuel production rate kg output/kg input	Load min % of max capacity	Electrical consumption kWh_{el}/output	Excess heat > 80^o kWh_{th}/output
MeOH plant - CO2	H_2/MeOH CO_2/MeOH	kg_{MeOH}/h	5.26[1] 0.73[1]	20[2]	0.316[3]	0.68[3]
MeOH plant - Biogas	H_2/MeOH Biogas/MeOH	kg_{MeOH}/h	22.0[1] 1.17[1]	20[2]	1.31[4]	1.23[4]
MeOH plant - Biomass	H_2/MeOH Biomass/MeOH	kg_{MeOH}/h	15.7[1] 0.86[7]	20[2]	0.64[7]	0.43[7]
DAC plant	Air/CO_2	kg_{CO_2}/h	-	0	1.7[13]	0
Pyrolysis plant[14]	Digestate/Gas Digestate/Char Digestate/Oil	$kg_{digestate}$/h	0.15 0.18 0.09	0	0.14[15]	0.28[15]

[1] Based on [6] - stoiciometrically defined with 100% conversion of carbon and gases.

[2] Based on [34].

[3] Based on [35].

[4] Based on [36].

[7] Consumption of non-purified water assuming a purification efficieny of 80% based on [7].

[13] Estimate based on [39] and [6].

Table 44: Economic data for the different types of Methanol plant units considered in the model

Type of units	Capacity -	Investment €/Capacity	Fixed cost €/Capacity/y	Variable cost €/Output	Lifetime Years	Annuity -
MeOH plant - CO2	kg_{MeOH}/h	23670[1]	947[2]	0	20[3]	0.088
MeOH plant - Biogas	kg_{MeOH}/h	30770[4]	1231[2]	0	20[3]	0.088
MeOH plant - Biomass	kg_{MeOH}/h	40000[5]	1600[2]	0	20[3]	0.088
DAC plant	kg_{CO_2}/h	6000[21]	300[21]	0	20[22]	0.102
Pyrolysis plant	$kg_{digestate}/h$	3028[23] OR 3788 from tech. cat.	401[24] OR 327 from tech. cat.	0	25	0.071

[1] For a small-scale 6.7 t_{MeOH}/h plant capacity based on [35], [41], [42], validated by [6].
Capital cost scaled by power law - scaling factor ∼0.7. [6] refers to a CAPEX of 17532€ per capacity installed
for medium-scale plant of 13.3 t_{MeOH}/h, and 8328€/Capacity for large-scale plant of 133 t_{MeOH}/h.

[2] 4% of capital investment based on [6].

[3] Based on [43].

[4] 130% of capital investment compared to MeOH plant - CO_2. Estimated additional cost of reformer
Based on [44], and assuming similar costs for electrical vs conventional reformers. Both validated by stakeholders.

[5] 130% of capital investment compared to MeOH plant - Biogas. Estimated additional cost of gasifier and gas cleaning units.
Based on [37], validated by stakeholders.

[23] Based on [3] with plant of 20 MW input biomass.

[24] 13.25% of capital investment based on [3].

7.1.5 Water supply units

The different water supply unit characteristics taking into account Bornholm's potential water resources are displayed in the *Table* 45 below:

Table 45: Water supply: the unit that provides purified water that can be directly used in the 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.

7.1.6 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 neighbouring 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 46: 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 CO_2 emissions infrastructure	$kg_{CO2}e$/($kg_{H_2 \text{max stored}}$)/year	-	0.006	-	0.006	0.006
CO_2 emissions during process	($kg_{CO2}e/kg_{H_2}$)/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 47: 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 CO_2 emissions infrastructure	$kg_{CO2}e/(kg_{H_2\text{max stored}})$/year	0.006	0.006	0.006
CO_2 emissions during process	$(kg_{CO2}e/kg_{H_2})$/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.

7.1.7 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% within a second. For the study, project partners estimate that accessing a depth of discharge (DoD) of 90% is feasible without incurring additional costs. It is anticipated that this percentage will reach 100% by 2030. Regarding efficiency, round trip losses are assumed to be around 0.1-0.12 kWh 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.

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Table 48: 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 CO_2 emissions infrastructure	$kg_{CO2}e$ / ($kWh_{max\ stored}$)/year	-	1.573	-	1.573	1.573
CO_2 emissions during process	($kg_{CO2}e$ / 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.

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7.2 General techno-economical input data for 2040 and 2050 of the PtX plant units

Table 49: 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 [6].
[2] 3% Capex based on [7].
[3] Using 10% Capex based on [6].
[4] 8.55% Capex based on [12].
[5] 3% Capex based on [10].
[6] Based on [10] for a working pressure around 100 bars.
[7] From [15].

Table 50: 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 [6].
[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 [8].
[6] Based on [9] assuming same values as of 2020.
[7] Based on communication with industrial partners.

Table 51: 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 [6].
[2] 4% Capex based on [6].
[3] For a very large-scale 190 t_{NH_3}/h plant capacity based on [6] (including ASU).
[4] Using the 2025 best value based on [7].
[5] 3% Capex based on [7].
[6] From [6].
[7] Using 10% Capex based on [6].
[8] 8.55% Capex based on [12].
[9] Based on [10] assuming that compressor and pressurized storage components cost will be half of 2025's costs.
[10] 3% Capex based on [10].
[11] Based on [10] for a working pressure around 100 bars.
[12] From [15].
[13] From [10] assuming low lithium price assuming same values as of 2030.
[14] 1.5% Capex based on [10].

Table 52: 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 [6].
[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 [8].
[6] Based on [9] assuming same values as of 2020.
[7] Based on communication with industrial partners.

7.3 Wastewater resource assessment and demand analysis for PtX in Bornholm

This section of the Appendix provides the detailed amount of water resources needed by the PtX plants evaluated all over this report and the availability of this resource around Bornholm, crucial for the operation of PtX plants.

Table 53 presents the amount of available water processed in the different wastewater treatment plants of Bornholm on a monthly basis.

Table 53: Available wastewater from different water treatment plants in Bornholm (2021)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Rønne [m^3]	312000	255000	287000	218000	213000	154000	160000	181000	190000	185000	308000	431000
Nexø [m^3]	145000	122000	124000	87000	84000	43000	64000	67000	75000	77000	158000	200000
Boderne [m^3]	163000	123000	138000	76000	80000	34000	53000	63000	53000	52000	143000	201000
Tejn [m^3]	114000	68000	87000	50000	57000	31000	54000	45000	35000	47000	76000	137000
Svaneke [m^3]	80000	54000	62000	40000	48000	19000	29000	27000	31000	38000	63000	95000
Melsted [m^3]	23000	13000	17000	9000	13000	5000	12000	11000	8000	9000	15000	25000

Table 54 below displays the 'maximum water demand' conditions derived from the large-scale PtX plant scenarios. These conditions of maximum demand correspond to the needs required for the production of ammonia, which requires 0.8626 million m^3 of water annually.

Table 54: Maximum water demand for the large-scale Power-to-X plant under the deterministic analysis (H_2 and NH_3)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
[m^3]	112106	95945	76807	91360	68126	82311	54520	65951	80930	99202	78916	96052

Table 55 below displays the 'maximum water demand' conditions derived from the large-scale PtX plant scenarios. These conditions of maximum demand correspond to a mix of Scenario 3 and Scenario 4 for methanol production, which requires 72110 m^3 of water annually.

Table 55: Maximum water demand for the small-scale Power-to-X plant under the deterministic analysis (MeOH).

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
[m^3]	7000	5211	5903	7404	6383	5978	2995	6367	6624	6992	5142	6110

7.4 Bornholm's current District Heating sources and PtX excess heat integration

This section of the Appendix offers an in-depth look at the current state of Bornholm's district heating system and the integration of the excess heat form the PtX plant into this system.

Currently, the island's heating needs are met by seven heat-producing sources, collectively supplying about 336 GWh of heat annually, as depicted in *Figure* 26 below.

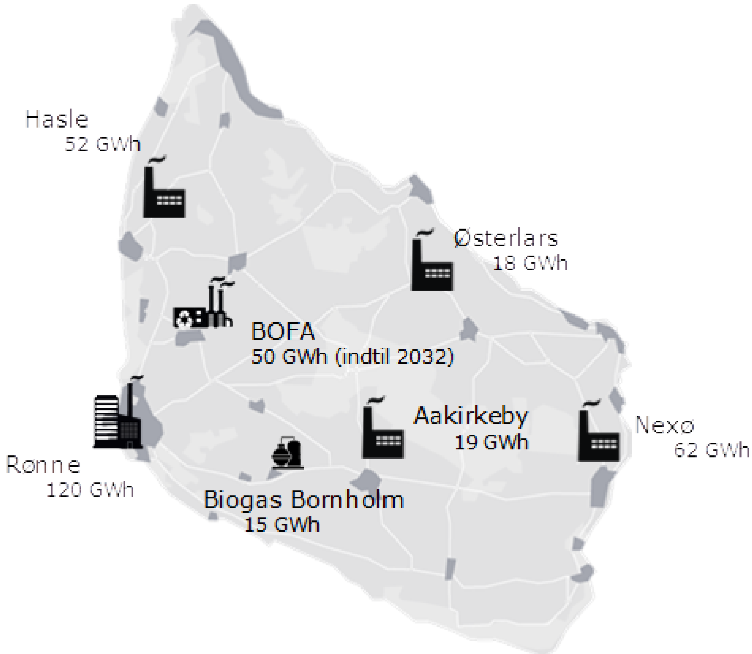


Figure 26: Annual heat production from different plants in Bornholm for 2021. Image provided by BEOF.

Taking the values displayed in the previous figure and using the production dynamics of Nexø heat plant, the monthly heat supply values for all the heat plants in Bornholm were calculated. The corresponding amounts are shown in *Table* 56 below:

Table 56: Heat supply from different heat plants in Bornholm (2021)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Rønne [GWh heat]	17.40	15.39	14.69	12.27	6.36	3.23	1.66	3.82	5.10	9.23	12.34	18.51
Nexø [GWh heat]	8.99	7.95	7.59	6.34	3.29	1.67	0.86	1.98	2.64	4.77	6.38	9.56
Hasle [GWh heat]	7.54	6.67	6.37	5.32	2.76	1.40	0.72	1.66	2.21	4.00	5.35	8.02
BOFA [GWh heat]	7.25	6.41	6.12	5.11	2.65	1.34	0.69	1.59	2.13	3.84	5.14	7.71
Aakirkeby [GWh heat]	2.75	2.44	2.33	1.94	1.01	0.51	0.26	0.61	0.81	1.46	1.95	2.93
Østerlars [GWh heat]	2.61	2.31	2.20	1.84	0.95	0.48	0.25	0.57	0.77	1.38	1.85	2.78
Biogas BHM [GWh heat]	2.17	1.92	1.84	1.53	0.80	0.40	0.21	0.48	0.64	1.15	1.54	2.31

Table 57 below shows the excess heat produced in the hydrogen and ammonia synthesis for each of the 6 large-scale deterministic scenarios, throughout the year.

Table 57: Heat generated from the hydrogen and ammonia production in the different large-scale PtX scenarios

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
H_2-AEC [GWh heat]	48.75	42.98	33.14	29.66	29.09	22.59	23.52	14.29	25.16	36.83	35.09	33.52
H_2-SOEC [GWh heat]	0	0	0	0	0	0	0	0	0	0	0	0
H_2-MIX [GWh heat]	36.56	32.23	24.85	22.24	21.82	16.95	17.64	10.72	18.87	27.62	26.32	25.14
NH_3-AEC [GWh heat]	56.56	48.41	38.73	34.68	34.20	26.51	27.50	16.86	29.67	43.18	39.82	39.10
NH_3-SOEC [GWh heat]	0	0	0	0	0	0	0	0	0	0	0	0
NH_3-MIX [GWh heat]	42.38	36.25	29.06	26.01	25.68	19.89	20.63	12.65	22.26	32.43	29.83	29.34

Table 58 below displays the excess heat produced in the methanol synthesis for each of the 4 small-scale deterministic scenarios, throughout the year.

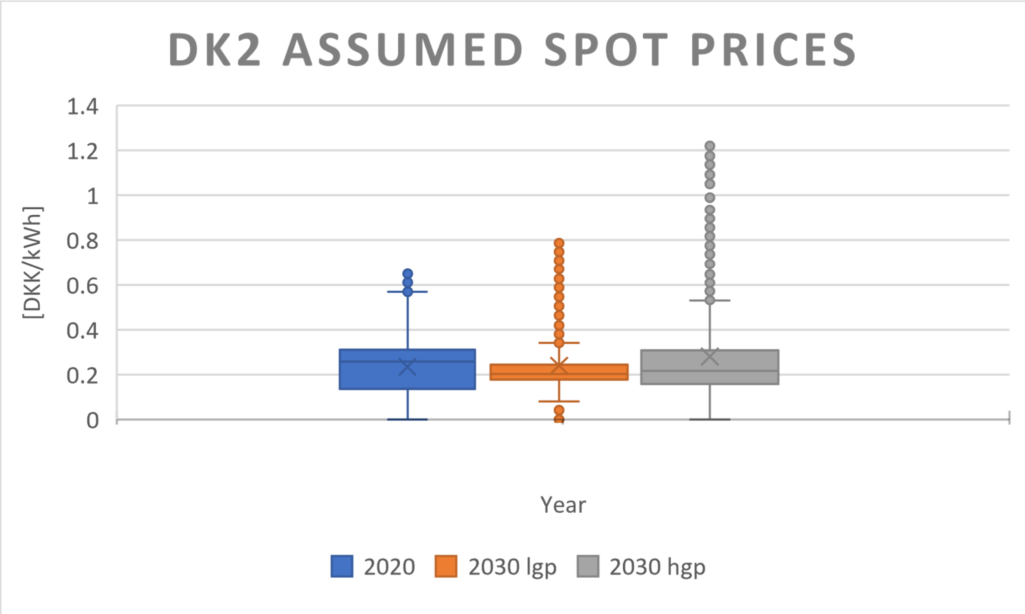
Table 58: Heat generated from the methanol production in the different small-scale PtX scenarios

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Scenario 1 [GWh heat]	7.07	6.55	8.10	8.65	8.51	8.49	4.61	8.32	8.35	8.69	7.29	8.12
Scenario 2 [GWh heat]	8.81	8.07	9.94	10.34	10.21	10.18	5.52	10.10	10.03	10.39	8.82	9.77
Scenario 3 [GWh heat]	11.15	10.22	12.83	12.97	12.03	12.33	6.38	12.09	12.44	13.06	11.40	12.53
Scenario 4 [GWh heat]	12.90	11.72	14.56	14.72	13.68	13.99	7.25	13.79	14.16	14.85	12.98	14.29

7.5 2030-DK2 grid electricity spot prices

This subsection focuses on the projected electricity spot prices within the DK2 grid for the year 2030. These projections are crucial for understanding the economic landscape of energy production, particularly for Power-to-X (PtX) applications. To obtain a comprehensive view, we used the Balmorel model to simulate two distinct scenarios based on different gas price assumptions: Low Gas Price (LGP) and High Gas Price (HGP). These scenarios offer insights into the potential variability of electricity costs under differing market conditions.

Figure 27: Assumed DK2 grid electricity spot prices for the years 2020 and 2030. 2030 is based on two separate simulations run using Balmorel assuming either LGP or HGP - Low/High-Gas-Price.



7.6 Comparative analysis of AEC and SOEC technologies in PtX plant for methanol production

So far all the results provided have been with the electrolysis done in Solid-Oxide Electrolysis Cells. An alternative, the Alkaline Electrolysis Cells, is investigated. The motivation to do this is to examine the sensitivity of the levelized cost of methanol to the electrolyzer technology and to analyse what this change means in terms of excess heat available for district heating integration in the four presented scenarios. The district heating integration is motivated by the desire to - on a longer timeline - be able to heat Bornholm's district heating network largely with waste heat from industrial processes rather than conventional central heating plants.

Running the model for the three main pathways introduced, Pathway 1-3, with the AEC instead of the SOEC, the resulting methanol production costs increase. This is due to the assumption of almost identical electrolyzer costs in 2030 and a lower efficiency of the AEC. Thus, the capacity of the AEC is larger than the SOEC, and the amount of renewable power sources is also larger. The production costs of the AEC-fueled methanol production are presented in *Table* 59. In all cases, the MeOH production cost increases, but pathway 2 is less sensitive to this, as only a small amount of electrolysis is needed in this pathway. Pathway 3 experienced an even larger competitive performance drop, as the SOEC was heat integrated into this pathway in combination with the gasifier.

Table 59: MeOH production costs of pathway 1-3 with AEC - compared with SOEC costs.

	Pathway 1 (PS CO_2)	Pathway 2 (biogas)	Pathway 3 (wood)
Fuel production cost [€/MWh]/[€/kg]	304.92/1.69	211.23/1.17	211.62/1.17
Percentage increase compared to the SOEC pathways [%]	7.93	2.42	6.30

Each MeOH production technology produces some excess heat from processes and the electrolysis produces oxygen as a by-product. Pathway 3, biomass to MeOH, does not produce oxygen available for sale as all of the oxygen is assumed used in the gasifier [37]. Pricing the heat suitable for district heating integration at 20€/MWh, and allowing the opportunity to sell oxygen at a price of 0.05 €/kg the levelized cost of methanol can be slightly reduced for the pathways. Continuing the comparison of the SOEC and AEC electrolyzer technologies the amount of excess heat generated, dependent on the electrolyzer, is assessed. The total annual production for each pathway and electrolyzer type can be seen in *Table* 60. For the SOEC pathways, Pathway 2 generally has a large excess heat production because the biogas reforming is electrically heated and results in a significant amount of waste heat, whereas Pathway 1 is not assumed to have significant heat generation besides in the electrolysis process, and Pathway 3 is assumed mostly heat integrated with the SOEC and its operation is of smaller scale.

Table 60: Excess heat generation of e-biomethanol plants with varying feedstock and varying electrolyzer technology.

	Pathway 1 (PS CO_2)	Pathway 2 (biogas)	Pathway 3 (wood)
Excess heat (SOEC) [GWh/yr]	21.24	92.74	19.96
Excess heat (AEC) [GWh/yr]	54.99	112.17	36.85
Difference [%]	159%	21%	85%

Fig. 29 shows the cost breakdown with by-product sales for each pathway - for both the SOEC and AEC electrolyzer choices. It can be seen that the pathways converting CO_2 have a larger potential for oxygen sale as the amount of hydrogen needed in these pathways is bigger. Meanwhile, the sale of heat for district heating barely impacts the 3 pathways. Comparing the heat sale of pathway 3 with SOEC vs AEC it becomes more clear that the excess heat in this pathway is nearly doubled with the AEC electrolyzer.

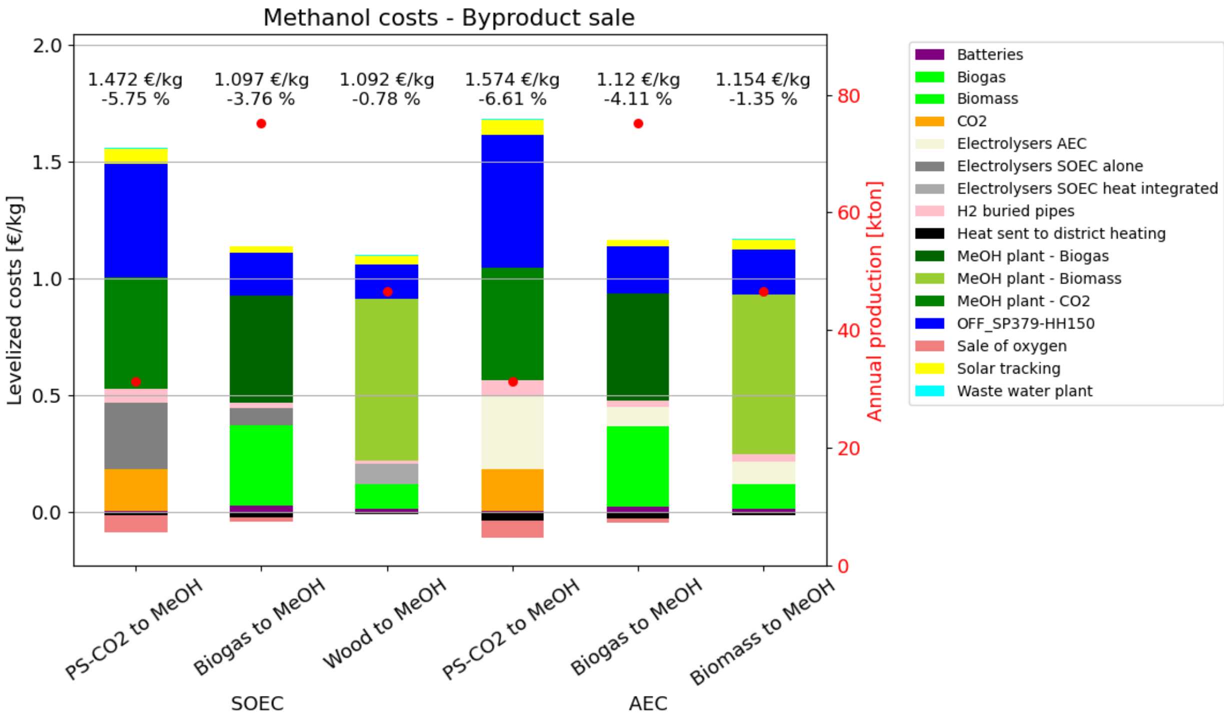


Figure 28: Breakdown of costs of each of the three main pathways with byproduct sale. Both the SOEC and AEC electrolyzer investment options are shown. The percentages indicate the relative cost reduction compared to the levelized cost of methanol without by-product sales in each pathway.

Comparing the LCOF with and without by-product sales the reductions experienced in each pathway are on average 6.18%, 3.94%, and 1.06% respectively. Along with the uncertainty of whether or not there is a market for oxygen sales, this highlights that whether or not by-product sale is achieved is not the deciding factor on the feasibility of a methanol-producing PtX plant.

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7.7 Optimal PtX plant sizing and cost analysis for the Methanol framework production pathways

The optimal sizing of the different PtX plant units for the 4 described methanol production pathways using weather data from 2020 (typical/average year) is displayed in *Table* 61 below.

Table 61: Optimal sizing of the Power-to-X plant units for different methanol production pathways under the deterministic analysis (typical/average weather year, 2020)

	Pathway 1 ($PS\ CO_2$)	**Pathway 2 (biogas)**	**Pathway 3 (wood)**	**Pathway 4 ($DAC\ CO_2$)**
Offshore Wind Farm [1] [MW]	60.15	55.36	26.42	758.25
Solar PV Park [2] [MWp]	40.00	40.00	39.34	40.00
Electrolysis plant (SOEC) [t H_2/h]/[MW_{in}]	1.28/55.29	0.81/35.01	0.58/19.84	11.81/510.38
Wastewater treat. plant [m^3 H_2O/h]	14.61	9.28	6.59	135.30
Methanol prod. plant [3] [t MeOH/h]				
Input: CO_2	4.07	*	*	40.00
Input: Biogas	*	9.82	*	*
Input: Wood chips	*	*	5.98	*
Batteries [MWh]	8.08	90.97	32.07	862.06
H_2 storage (buried pipes) [t]	69.01	58.87	28.12	552.48
DAC unit (CO_2 capture) [t CO_2/h]	*	*	*	54.96

[1] The model selected the SP379-HH150 turbine as the optimal choice from the available catalogue for all model runs.
[2] The model selected 1-axis tracking solar PV as the best solar PV technology for all model runs. The capacity of the solar park was capped at 40MW.
[3] The values on this table refer to the total capacity/cost of all the different units constituting the methanol plant for each case.

The methanol production cost and total annualized system cost for each of the studied pathways were also examined. *Figure* 29 shows a graphical representation of these economic indicators for the four specific methanol production pathways using weather data of an average/typical year (2020). In the graph, each pathway is represented by a stacked bar i 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. Finally, the fuel production volumes for each case are displayed under the pathway name in the x-axis. It is assumed that the energy density for MeOH is 5.53 MWh/ton [50].

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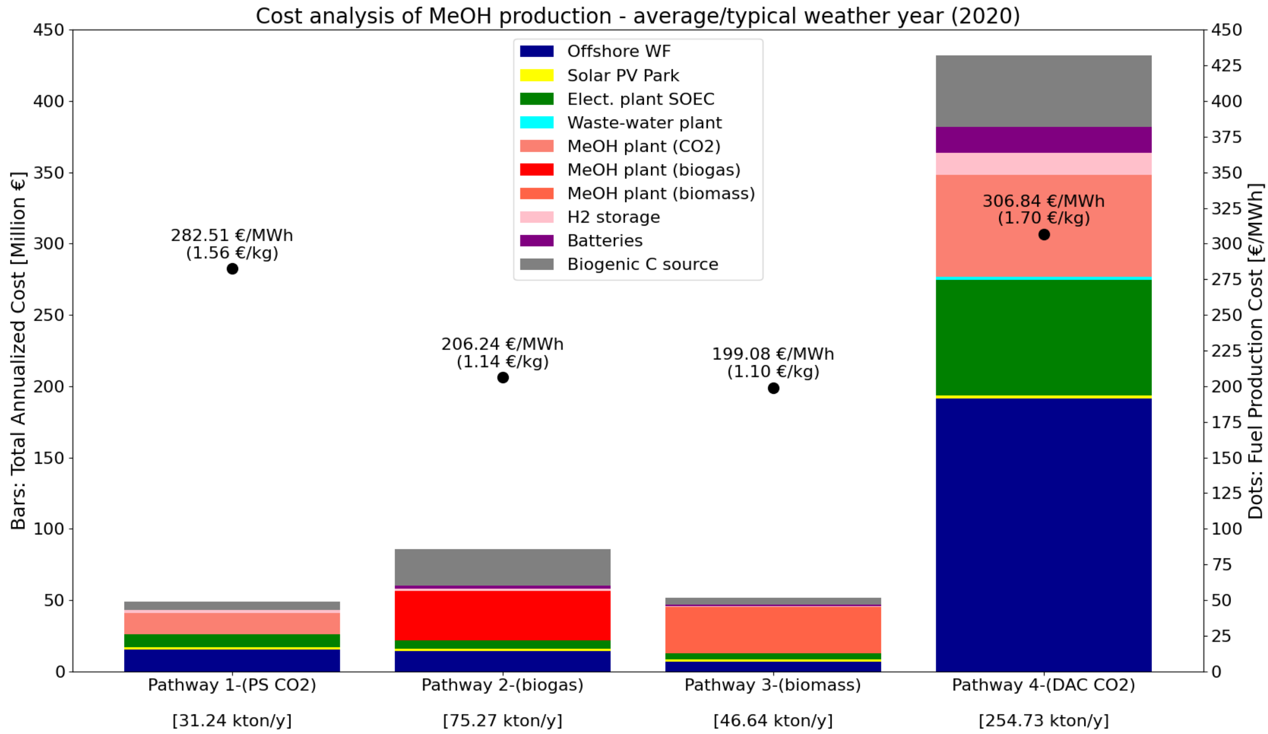

Figure 29: Comparative cost analysis for the 4 studied pathways in an average/typical weather year (2020).

In addition to the graph shown above, *Table* 62 provides a numerical summary of the total annualized system cost and *Table* 63 of the fuel production cost and fuel produced for all the pathways within the average/typical year. This allows for a quick reference and a more clear visualization of the broken-down costs of the different methanol production pathways.

Table 62: Breakdown of the annualized total system cost of the large Power-to-X plant by unit for different methanol production pathways under the deterministic analysis (typical/average weather year, 2020) -all costs are in [M€/year]-.

	Pathway 1 (PS CO_2)	**Pathway 2 (biogas)**	**Pathway 3 (wood)**	**Pathway 4 (DAC CO_2)**
Offshore Wind Farm	15.19	13.98	6.67	191.48
Solar PV Park	1.91	1.91	1.88	1.91
Electrolysis plant (SOEC)	8.79	5.58	4.02	81.37
Wastewater treatment plant	0.23	0.15	0.11	2.13
Methanol production plant				
Input: CO_2	14.94	*	*	71.54
Input: Biogas	*	34.68	*	*
Input: Wood chips	*	*	32.33	*
Batteries	0.17	1.91	0.67	18.13
H_2 storage (buried pipes)	1.93	1.64	0.79	15.43
Biogenic C source	5.62	25.96	4.85	50.07
TOTAL	48.78	85.81	51.32	432.06

Table 63: Fuel production costs of different methanol production pathways under the deterministic analysis (typical/average weather year, 2020).

	Pathway 1 (PS CO_2)	**Pathway 2 (biogas)**	**Pathway 3 (wood)**	**Pathway 4 (DAC CO_2)**
Fuel production cost [€/MWh]/[€/kg]	282.51/1.56	206.24/1.14	199.08/1.10	306.84/1.70
Total amount of produced fuel [GWh/year]/[kton/year]	172.67/31.24	416.09/75.27	257.79/46.64	1408.09/254.73

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