Techno-economic model for evaluating the economic feasibility of green hydrogen production within an electrical storage and grid-connected system

Prabhat Ranjan

School of Electrical Engineering

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Thesis supervisor:

D.Sc. (Tech.) John Millar

Thesis advisor:

M.Sc. Dario Nikzad

Aalto University
School of Electrical Engineering

AALTO UNIVERSITY
SCHOOL OF ELECTRICAL ENGINEERING

ABSTRACT OF THE
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Author: Prabhat Ranjan

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The transition to a low-carbon energy system has increased interest in green hydrogen as a sustainable energy carrier. This thesis presents a comprehensive techno-economic model designed to assess the economic feasibility of green hydrogen production within an RES integrated system that includes electrical storage and grid connectivity.

The model takes into account real-time electricity market dynamics, variability in renewable energy sources (RES), and interactions among system components such as the electrolyser, battery, RES assets, and the grid. Using a mixed-integer linear programming (MILP) approach, optimal dispatch schedules are derived to minimise costs and maximise revenues from hydrogen production and participation in the energy market for a given system configuration.

A large number of simulations are conducted with varying system configurations to create a landscape of hydrogen generation prices. The case studies, which apply real-world data, indicate that under current market conditions, green hydrogen does not achieve parity with conventional grey hydrogen. Additionally, the inclusion of electrical storage appears to negatively affect profitability.

Key parameters, such as electricity prices, capital expenditures (CAPEX), and local factors, critically influence the viability of green hydrogen projects. Furthermore, maintaining a high capacity factor for the electrolyser depends significantly on grid connection. The findings conclude that, to make green hydrogen generation profitable with on-site assets, it is necessary to oversize RES assets and ensure that grid charges and power prices are favourable. While high variability in power prices may benefit arbitrage opportunities, it currently does not sufficiently offset the capital costs associated with electrical storage.

Keywords: Green hydrogen, optimisation, techno-economic modelling, Grid charges, Levelised cost of hydrogen, Battery cycle, arbitrage, dispatch schedule, policy, price forecasting

Contents

Symbols and abbreviations

Abbreviations

η^{batt}	Battery charging or discharging efficiency (%)
A_t	Amortisation amount (EUR/yr)
C	Capital cost
$CAPEX$	Capital Expenditure ($\frac{EUR}{MW}$)
CF_{min}^{PEM}	Minimum capacity factor of the electrolyser, which has to be fulfilled every $H_{lookahead}$ period (%)
$Cost_{O\&M}$	Operating and maintenance cost ($\frac{EUR}{MW-yr}$)
$Cost_{Var}$	Variable cost incurred which running an asset ($\frac{EUR}{MWh}$)
E_t^{batt}	Energy content of the battery at time t (MWh)
$H_{lookahead}$	The time period over which the electrolyser has to run with at least the minimum target capacity factor which is $CF_{min,PEM}$ ($hours$)
d	Discount rate (%)
$debt\%$	Share of total costs taken as debt (%)
H	Produced hydrogen ($tons-of-H_2$)
H_{SEC}	Specific energy consumption, The amount of energy (kWh) used by electrolyser to produce one kg of Hydrogen ($\frac{kWh}{kg-of-H_2}$)
i	Interest rate (%)
$LCOE$	Levelised cost of Electricity ($\frac{EUR}{MWh}$)
$LCOH$	Levelised cost of Hydrogen Production ($\frac{EUR}{kg-of-H_2}$)
$lookahead$	Time period over which system can run the optimisation cycle ($hours$)
$NLDC$	Net Discounted Lifetime Cost (EUR)
$O\&M_t$	Operating and maintenance cost (time-dependent)
$OPEX$	Operational Expenditure ($\frac{EUR}{MW-yr}$)
P_t	Hourly throughput of a resource (MW) at time t. It is $+ve$ when it is feeding the system and $-ve$ when it is taking power out of the system
$P_{t,in}^{grid}$	Power consumed by the system from the grid ($\frac{EUR}{MWh}$). It is $+ve$ from system perspective.
$P_{t,out}^{grid}$	Power supplied by the system to the grid ($\frac{EUR}{MWh}$). It is $-ve$ from system perspective.
PEM	Proton Exchange membrane electrolyser
Th_d	Discounted throughput of a resource
$Tarrif_t^{Feed-in}$	Hourly price of consuming electricity from the grid ($\frac{EUR}{MWh}$)
$Tarrif_t^{Feed-out}$	Hourly price of supplying electricity to the grid ($\frac{EUR}{MWh}$)
Var_t	Variable cost (time-dependent)
$ELCC$	Effective load carrying capacity

1 Introduction

Following the recent energy crisis in Europe, there has been a significant shift towards alternative energy sources, particularly to replace fossil gas, which is valued for its high energy density and operational flexibility. Fossil gas plays a crucial role in manufacturing, as it is essential for producing raw materials and providing energy for various processes. Europe has an extensive network of gas pipelines across the continent, enabling the efficient transportation of large quantities of energy in the form of pumped natural gas. These pipelines are critical, as the long-term storage of natural gas poses considerable challenges.

To address the gas shortage, many alternative fuels have been investigated as substitutes for fossil gas. Notably, renewable energy sources such as solar, wind, and biomass are gaining traction. In addition to addressing climate concerns, Europe is prioritizing these resources to ensure energy security. However, while these alternatives provide some relief from the gas shortage, they cannot fully replace fossil gas due to two key properties: its exceptionally high energy density and flexibility of operation.

To improve the situation, solutions such as integrating battery storage with renewable energy systems have been proposed to enhance their Effective Load Carrying Capacity (ELCC) - a measure of how much of the total capacity can be considered ideal, embodying infinite ramping capability and 100% availability. Although this solution is effective, the integration of battery technology significantly increases the overall cost of the system and fails to match the energy density of gas. Additionally, the production of batteries requires a variety of materials, including rare earth metals.

One potential solution that has been gaining a lot of attention lately is combustible gaseous hydrogen. It boasts a very high energy density, ranging from 120 to 140 MJ/kg [1]. This hydrogen can be utilised in rotating generators in cycles similar to those of gas turbines, which can provide the necessary inertia to the system. Additionally, it can be produced sustainably, which means it can be classified as green hydrogen.

Classification of hydrogen:

1. **Green Hydrogen**: Green hydrogen refers to hydrogen produced through water electrolysis with no carbon emissions. This process requires electricity sourced from renewable energy, such as solar and wind power.

2. **Blue Hydrogen**: Hydrogen is produced through the steam reforming of natural gas, while the resulting CO_2 emissions are captured and processed, preventing any CO_2 release.

3. **Turquoise hydrogen**: Hydrogen produced through methane pyrolysis involves a process in which natural gas is converted into hydrogen and solid carbon. This reaction is endothermic, meaning it requires an input of energy. The carbon neutrality of this process largely depends on the energy source used for the blast furnace during pyrolysis. Additionally, extracting natural gas can

lead to emissions. As a result, the entire process generally cannot be classified as carbon-neutral.

4. **Black & Grey Hydrogen**: This type of hydrogen is produced through the steam reforming process of natural gas or coal, which releases emissions directly into the atmosphere.
5. **Pink hydrogen**: Pink hydrogen refers to hydrogen produced through electrolysis using electricity sourced from nuclear power. It is also sometimes referred to as red or purple hydrogen.

1.1 About the project

To determine the optimised cost of green hydrogen generation, this thesis develops an optimisation model that calculates the Levelised Cost of Hydrogen (LCOH) for various configurations and locations. The price input derived from the grid has been meticulously calculated using comprehensive billing forecasts, which provide a detailed overview of energy costs, regulated charges, and network fees.

1.2 Goal of the project

The primary objectives of this research are to find out the following three research questions:

1. What is the cost of hydrogen production with all-in grid prices in various market environments?
2. How does onsite generation, including solar and wind with grid support, impact hydrogen production across different markets?
3. What is the effect of electrical storage on the cost of hydrogen production in different markets?

In order to achieve this goal the following methods are followed:

1. **Develop a detailed techno-economic model:** To develop a comprehensive model that includes the essential technical and economic factors of green hydrogen production, energy storage, and grid integration.
2. **Analyse the impact of key parameters:** To assess how the economic feasibility is affected by changes in key parameters, including renewable energy costs, electrolyser efficiency, storage capacity, and grid electricity prices.
3. **Evaluate the economic viability under different scenarios:** To evaluate the economic viability of green hydrogen production across various scenarios, including different levels of renewable energy integration, grid configurations, and policy incentives.

4. **Identify optimal system configurations:** The goal is to identify the best system configurations that maximise economic benefits while minimising environmental impact.
5. **Provide insights for policy and investment decisions:** To offer valuable insights for policymakers and investors in shaping the future of green hydrogen production and deployment.

To capture various characteristics of the European market, six countries have been selected, representing five major clusters. The model does not take into account any special schemes or policies implemented by local governments when calculating prices. The clusters are as follows:

1. **Nordics**: The Nordic countries benefit from relatively stable annual prices due to their efficient electricity grids, flexible energy generation, and substantial electrical storage capacity, primarily through pumped hydro. However, besides hydroelectric power, the Nordics have limited potential for solar energy, and wind production is also lower compared to other regions. For this analysis, Finland and Sweden have been selected to represent the Nordic conditions.
2. **Central Europe**: Central Europe features a demand-intensive grid, which typically results in high prices and significant price variations. These countries are well-connected to continental Europe, allowing them to access a larger pool of generating assets, which can lead to lower prices. Nevertheless, heavy demand and inadequate transmission capacity across bidding zones can cause prices to diverge between countries. Germany and France have been chosen to represent the conditions in Central Europe for this analysis.
3. **Southern Europe**: Similar to Central Europe, Southern Europe is also energy-intensive but benefits from a considerable amount of renewable energy sources (RES) generation, particularly high solar and wind power. This situation often leads to elevated prices and substantial price fluctuations. Italy has been selected to represent the Southern European market conditions in this analysis.
4. **Iberia**: The Iberian Peninsula shares similarities with Southern Europe; however, it boasts several renewable energy hotspots due to its geographical features. This can make the production of green hydrogen more economically viable. For this analysis, Spain has been chosen to represent the Iberian conditions.

2 Literature Survey

2.1 About Hydrogen

Hydrogen is the lightest and most abundant molecule in the universe. The use of hydrogen as a fuel for fusion is currently being explored, with potential applications for future energy security. In fact, the sun operates on the fusion of hydrogen, and the hydrogen bomb is based on the same principle. However, for this project, we will only consider the generation of energy through the combustion of hydrogen and its derivatives, such as ammonia.

Hydrogen serves as an energy carrier and is generally not used directly to produce electricity. However, it is viewed as a promising energy storage solution due to its high gravimetric energy density. Some combustion engines can utilise hydrogen in a thermodynamic cycle to generate electricity. This process offers several benefits, including the fact that no greenhouse gases are produced when using water electrolysis. In the past decade, hydrogen has gained traction in the mobility sector, where it is used in combustion engines as an alternative to gasoline. However, the efficiency achieved with this method is only around 20-25% [2]. The static generators on the other hand can achieve an efficiency of up to 80% with hydrogen without producing any pollutants. [3]

2.2 About Green Hydrogen

Green hydrogen has been a topic of extensive discussion. It refers to hydrogen produced using electricity generated from renewable sources, such as wind and solar energy. Green hydrogen serves as an energy source that can replace carbon-intensive gases. Additionally, hydrogen and its derivatives, such as ammonia and methanol, are essential feedstocks for major industries, including steel, fertilisers, and pharmaceuticals. Most of the demand for hydrogen comes from manufacturing rather than energy production.

While hydrogen can be used directly as an energy source in automobiles, these vehicles are currently expensive and not very popular due to various factors. The generation of green hydrogen can be achieved through several technologies, making it a significant area of accelerated research and development.

2.2.1 Renewable Energy Sources for Green Hydrogen Production

Green hydrogen's environmental sustainability relies on using renewable energy sources to power the electrolysis process. Several renewable energy technologies can be employed for this purpose.

Solar Photovoltaic (PV): Solar PV systems have experienced significant cost reductions and efficiency improvements in recent years, making them an increasingly attractive option for green hydrogen production [18]. The intermittent nature of solar PV generation necessitates integrating energy storage solutions to ensure a continuous hydrogen production rate.

Wind Energy: Wind turbines provide another significant source of renewable electricity, particularly in regions with abundant wind resources [19]. Like solar photovoltaic power generation, wind power generation is intermittent, requiring careful system design and control strategies for integration with hydrogen production.

Hybrid Renewable Energy Systems: Combining different renewable energy sources, such as solar PV and wind, can mitigate the impact of intermittency and improve the overall reliability of the hydrogen production system. Hybrid systems can also optimise the utilisation of available resources and reduce the need for large-scale energy storage.

2.2.2 Electrical Storage Technologies for Green Hydrogen Systems

Energy storage is crucial in enabling renewable energy sources' efficient and reliable integration with green hydrogen production. Various storage technologies can be used to address the intermittency of renewable generation.

Battery Energy Storage Systems (BESS): BESS, particularly lithium-ion batteries, offer fast response times, high efficiency, and modularity, making them suitable for short-term energy storage and ancillary services of the grid [20]. However, batteries' high capital cost and limited energy storage capacity can constrain large-scale hydrogen production.

Pumped Hydro Storage (PHS): PHS is a mature and cost-effective technology for large-scale energy storage, offering long discharge durations and high round-trip efficiencies [21]. However, PHS requires specific geographical conditions and has limited deployment potential in certain regions.

Hydrogen Storage: Hydrogen itself can be stored in various forms, including compressed gas, liquid hydrogen, and metal hydrides [22]. Hydrogen storage offers long-duration energy storage capabilities and can decouple hydrogen production from demand, providing flexibility to the energy system.

2.2.3 Grid Integration of Green Hydrogen Production

Incorporating green hydrogen production systems into the existing electricity grid presents challenges and opportunities.

Grid Stability and Ancillary Services: The intermittent nature of renewable energy sources and the fluctuating demand for hydrogen can affect grid stability, requiring careful management and control strategies [23]. However, green hydrogen production systems can also provide ancillary services to the grid, such as frequency regulation and voltage control, enhancing grid stability and reliability.

Demand Response and Grid Flexibility: Hydrogen production can be modulated to respond to grid signals, providing demand response capabilities and optimizing grid operation. This flexibility can help balance supply and demand, reduce grid congestion, and integrate higher shares of renewable energy.

2.3 Contemporary Technologies

The primary way to generate green hydrogen is through fuel cells. There are several kinds of fuel cells that have different operating capabilities, such as operating temperature, specific energy consumption, efficiency, etc., along with different costs.

These fuel cells are divided into six major groups. [9]. Apart from the six groups presented at the Table 1, multiple other types of electrolysers have target use cases and are not discussed here.

1. Alkaline Fuel Cell (AFC) - Alkaline Water Electrolysis (AWE) is a mature and commercially available technology characterized by its relatively low capital costs and robust operation [11]. However, AWE systems typically exhibit lower current densities and efficiencies than other electrolyzers, and their dynamic response to fluctuating renewable energy inputs can be limited [12].

2. Proton exchange membrane fuel cell (PEMFC) - Proton exchange membrane electrolysis (PEM) offers higher current densities, faster start-up and shut-down times, and improved efficiency compared to AWE, making them well suited for integration with intermittent renewable energy sources [13]. However, PEM systems generally have higher capital costs due to the use of expensive materials such as platinum catalysts and titanium components. For our analysis, we have used the properties of proton exchange membrane fuel cells as a reference.

3. Solid Oxide fuel cell (SOFC) - Solid Oxide fuel cell (SOFC) or Solid Oxide Electrolysis Cells (SOEC) operate at high temperatures (700-1000 °C), enabling potentially higher efficiencies and the possibility of utilizing waste heat [14]. However, SOEC technology faces challenges related to material durability, long-term stability, and system integration.

4. Molten carbonate fuel cell (MCFC) - These fuel cells operate at a high temperature(550-660 °C) and are generally considered environmentally friendly. The electrolyte used here is a combination of alkali carbonates and LiAlO2. MCFC units are very stable and generally have a high capacity factor. [15]

5. Phosphoric acid fuel cell (PAFC): PAFC uses a pure phosphoric acid electrolyte in a silicon carbide matrix. Both the electrodes (cathode and anode) are made up of Platinum. PAFC operates at relatively low temperatures (150-220 °C) with a capacity factor greater than 95%. These fuel cells are known for their stable power production without power surges. This makes it ideal for running computer equipment and facilities such as hospitals, where waste heat is also used. [16]

6. Direct methanol fuel cell (DMFC): The DMFC uses methanol to produce electricity directly. It uses a polymer membrane as an electrolyte, similar to PEMFC. This fuel cell doesn't need any external reform since it directly uses methanol for the fuel cell reaction. This is mainly used for portable applications due to the fuel being liquid. However, this fuel cell has many issues, such as methanol crossover through the membrane, which leads to a loss of fuel and a slow reaction. [17]

Fuel cell	**Operating Temperature (°C)**	**System Output (kW)**	**Electrical Efficiency (%)**	**Combines Heat & Power (CHP) Efficiency**
AFC	90–100	10–100	60	>80
PAFC	150–200	50–1000	>40	>85
SOFC	600–1000	<1–3000	35–43	<90
MCFC	600–700	<1–1000	45–47	>80
PEM	50–100	<1–250	53–58	70–90
DMFC	60–200	0.001–100	40	80

Table 1: Technical characteristics of fuel cell technologies [10]

Fuel cell type	**AFC**	**PAFC**	**SOFC**	**MCFC**	**PEMFC**	**DMFC**
Common Electrolyte	Aqueous solution of potassium hydroxide	Liquid phosphoric acid	Yttria stabilized zirconie	Liquid solution of lithium, sodium, and/or potassium carbonates	Solid organic polymer poly-perfluorosulfonic acid	Solid polymer membrane
Anode reaction	$2H_2 + 4OH^- \rightarrow$ $4\mathrm{H}_2O + 4e^-$	$2H_2 \rightarrow 4H^+ + 4e^-$	$O_2^- + H_2(g) \rightarrow$ $\mathrm{H}_2O(g) + 2e^-$	$H_2O + CO_3^{2-} \rightarrow H_2O$ $+ \mathrm{CO}_2 + 2e-$	$H_2(g) \rightarrow 2H^+ + 2e^-$	CH_3OH^+ $\mathrm{H}_2O \rightarrow CO_2^+$ $6\mathrm{H}^+ + 6e^-$
Cathode reaction	$O_2 + 2H_2O + 4e^- \rightarrow$ $4\mathrm{OH}^-$	$O_2 + 4H^+ +$ $4\mathrm{e}^- \rightarrow H_2O$	$\frac{1}{2}O_2(g) + 2e^- \rightarrow$ $\mathrm{O}^{2-}(s)$	$\frac{1}{2}O_2 + CO_2 + 2e^-$ $\rightarrow CO_3^{2-}$	$\frac{1}{2}O_2(g) + 2H^+ + 2e^-$ $\rightarrow \mathrm{H}_2O$	$\frac{3}{2}O_2 + 6e^- + 6H^+$ $\rightarrow 3\mathrm{H}_2O$
Charge carrier	OH^-	H^+	O^-	CO_3^-	H^+	H^+
Fuel	Pure H_2	Pure H_2	H_2, CO, CH_4, other	H_2, CO, CH_4, other	Pure H_2	CH_3OH
Oxidant	O_2 in air	O_2 in air	O_2 in air	O_2 in air	O_2 in air	O_2 in air
Cogeneration	No	Yes	Yes	Yes	No	No
Reformer is required	Yes	Yes	–	–	Yes	–
Cell voltage	1	1.1	0.8–1.0	0.7–1.0	1.1	0.2–0.4

Table 2: Operational specifications of the Fuel cell technologies[10]

For the current analysis within the scope of the project, the **PEM (Proton Exchange Membrane) fuel cell** is chosen as the default, with a specific energy consumption of 55 MWh per ton of gaseous Hydrogen.

2.4 Techno-Economic Modelling of Green Hydrogen Systems

Techno-economic models are essential tools for evaluating the economic viability and technical performance of green hydrogen projects.

Levelized Cost of Hydrogen (LCOH): The LCOH is a commonly used metric for assessing the cost-effectiveness of various hydrogen production methods. It indicates the average cost of producing one kilogram of hydrogen throughout the project's lifespan, taking into account capital expenses, operating expenses, and energy inputs.

Techno-Economic Models and Optimisation : Techno-economic models integrate technical and economic parameters to assess the feasibility and performance of green hydrogen projects [24]. These models can be used to optimise system design, operating strategies, and investment decisions. Optimisation algorithms, such as linear programming and genetic algorithms, can be employed to identify optimal system configurations that minimise costs and maximise efficiency.

2.5 Current work

Despite significant advancements in the field of green hydrogen, several research gaps still exist:

Comprehensive Techno-Economic Models: There is a need for more detailed techno-economic models that can accurately capture the complex interactions between renewable energy sources, electrolysers, storage systems, and grid infrastructure.

Dynamic Modelling and Real-Time Control: Dynamic models are required to account for the time-varying nature of renewable energy and grid operations. These models will help in assessing system performance and in developing accurate real-time control strategies.

Uncertainty Analysis and Risk Assessment: Further research is necessary to address the uncertainties related to technology costs, energy prices, policy frameworks, and market conditions.

2.6 Legislation and Policies

The development and deployment of green hydrogen technologies are significantly influenced by national, regional, and international policy frameworks. This section reviews the evolution and current state of key hydrogen-related policies, focusing on their relevance to techno-economic modelling and project feasibility.

2.6.1 Early Policy Developments and Rationale (Global Context):

Globally, early hydrogen policies were predominantly focused on research and development (R&D) initiatives. These were motivated by concerns about energy security, local air pollution, and the long-term need for decarbonisation [25]. The U.S. Department of Energy (DOE) and its Hydrogen and Fuel Cell Technologies Office (HFTO) have played a significant role in funding hydrogen R&D [26]. Japan also initiated early efforts, recognising hydrogen's potential for energy diversification [27]. These early initiatives laid the groundwork for later, more comprehensive policy frameworks.

2.6.2 The European Hydrogen Strategy and its Context:

The European Union has led the development of a comprehensive and ambitious hydrogen strategy. This is driven by the EU's commitment to achieving climate neutrality by 2050, as outlined in the European Green Deal [28].

The EU Hydrogen Strategy (2020): The EU Hydrogen Strategy, published in 2020, outlines a vision for establishing a competitive hydrogen market in Europe and integrating hydrogen into the European energy system [29]. The strategy proposes a phased approach, initially focusing on the production of renewable hydrogen and its expansion across various sectors. Key targets include the installation of 6 GW of renewable hydrogen electrolysers by 2024 and 40 GW by 2030. Unfortunately, by the end of 2024, the total production capacity of electrolysers reached only 0.4 GW, falling significantly short of its ambitious goals [30].

REPowerEU Plan (2022): In response to the energy crisis triggered by the war in Ukraine, the EU launched the REPowerEU Plan, which further accelerates the deployment of renewable hydrogen [31]. This plan aims to increase the EU's renewable hydrogen production target to 10 million tonnes by 2030 and import an additional 10 million tonnes.

Focus on Renewable Hydrogen ("Green Hydrogen"): European policy strongly emphasises renewable hydrogen produced from renewable electricity sources. The EU has established strict criteria for defining renewable hydrogen, ensuring its alignment with decarbonisation goals. This focus is reflected in funding priorities and support schemes.

Hydrogen Valleys and Important Projects of Common European Interests (IPCEIs): The EU promotes the development of Hydrogen Valleys, regional ecosystems where hydrogen production, distribution, and use are integrated. The IPCEI mechanism provides funding for large-scale, cross-border hydrogen projects that contribute to EU objectives [32]. Several IPCEIs related to hydrogen have been approved, supporting hydrogen infrastructure development and technologies.

2.6.3 National Hydrogen Strategies within Europe:

Several European countries have developed their own national hydrogen strategies, complementing the EU strategy and tailoring it to their specific circumstances.

Germany's National Hydrogen Strategy: Germany's strategy sets ambitious targets for domestic hydrogen production and imports, focusing on industrial decarbonization and heavy-duty transport [33].

The Netherlands: The Netherlands aims to become a major hydrogen hub in Europe, leveraging its existing gas infrastructure and port facilities [34].

France: France's strategy focuses on developing a domestic hydrogen industry and supporting the deployment of hydrogen in transport and industry [35].

Other European Countries: Many other European countries, including Spain, Portugal, and Italy, have also developed or are developing national hydrogen strategies, demonstrating the widespread commitment to hydrogen within the EU.

2.6.4 Global Hydrogen Policy Developments (Brief Overview):

While Europe is leading in many aspects, other regions also make significant strides in hydrogen policy.

Asia: Japan has been a pioneer in hydrogen technology and policy, focusing on fuel cell vehicles and hydrogen for power generation [27]. South Korea has also established ambitious hydrogen targets [36].

Australia: Australia aims to become a major hydrogen exporter, leveraging its abundant renewable energy resources [37].

North America: The U.S. is increasing its focus on hydrogen, with the DOE launching various initiatives to support hydrogen production, infrastructure, and applications [38]. Canada has also developed a national hydrogen strategy [39].

2.6.5 Relevance to Techno-Economic Modelling:

The European policy landscape, with its emphasis on renewable hydrogen, specific targets, and support mechanisms, directly impacts the techno-economic modelling of hydrogen projects in Europe.

Eligibility for Funding and Incentives: Techno-economic models should consider the specific criteria for accessing EU and national funding programs and incentives, such as those related to renewable hydrogen production and IPCEI participation.

Carbon Intensity Requirements: The EU's focus on renewable hydrogen and related regulations on carbon intensity must be factored into the cost analysis and technology selection within models.

Grid Connection and Infrastructure Development: Policies related to grid connection and hydrogen infrastructure development can significantly influence project costs and feasibility.

Market Demand and Off-take Agreements: Policy support for hydrogen demand in various sectors can create market opportunities and influence off-take agreements, which are crucial for project economics.

By explicitly considering the European policy context, techno-economic models can provide more accurate and relevant assessments of regional hydrogen projects. This focused approach and a broader awareness of global trends are essential for informed decision-making in the rapidly evolving hydrogen sector.

3 Mathematical Modelling

This project aims to create a techno-economic model for green hydrogen, incorporating renewable generation assets such as solar and wind energy. The current model has been developed as a linear optimizer for the dispatch schedule of connected resources. Additionally, the model includes a connection to the grid, which can function both as a source and a sink of power, while adhering to specific constraints.

Electrical storage has also been integrated to evaluate the feasibility of the storage system. This includes the introduction of flexibility options and the ability to capture arbitrage opportunities enabled by feed-in tariffs available within the grid.

Key Features of the Model:

1. The linear optimization model optimizes the dispatch schedule, which is temporal (time-based) in nature.
2. Minimise the overall cost (or maximise revenue) within a constrained time window.
3. The current granularity for model input and output is hourly.
4. Generate hourly dispatch schedule, which is then summarised as monthly and annual summaries.

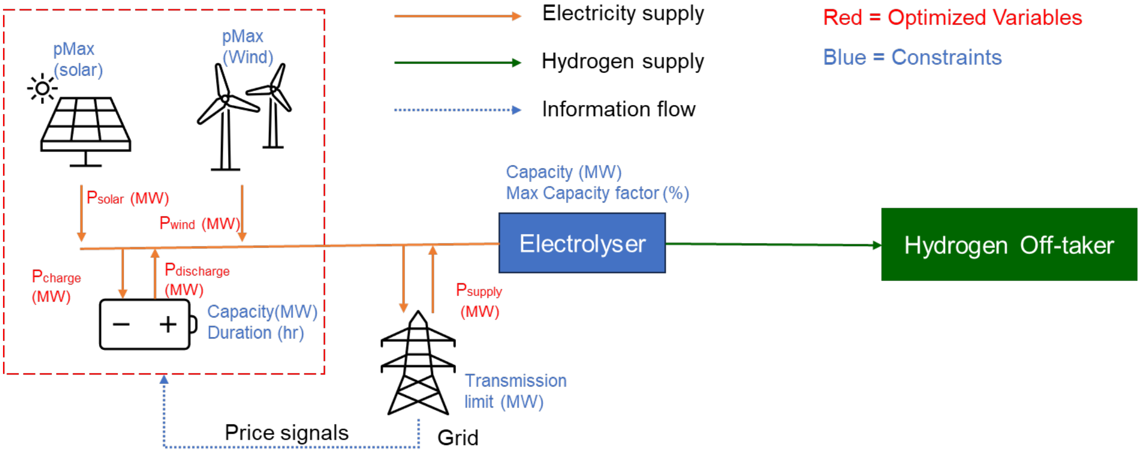

Figure 1: A graphic representation of the model

In the next few sections, various aspects of the mathematical modelling are described.

3.1 Constraints

In any linear programming model, it is essential to establish constraints in order to identify a feasible solution space. This particular model involves more than 50 variables, which means there are numerous constraints to consider. Each of these constraints is detailed in the following sections.

3.1.1 RES Constraints

Wind: The wind assets have a defined hourly location-based profile. Based on the locational profile, the wind generation at any hour ($P_{t,wind}$) can fluctuate between zero (0) to the maximum output at a particular hour ($P^{max}_{t,wind}$).

$$0 \leq P^{wind}_{t} \leq P^{wind}_{t,max} \tag{1}$$

Solar: Similar to wind, solar energy also features an hourly location-based profile, and hence, the output from solar energy at any hour ($P_{t,solar}$)is constrained between zero (0) and its hourly maximum ($P^{max}_{t,wind}$).

$$0 \leq P^{solar}_{t} \leq P^{wind}_{t,max} \tag{2}$$

3.1.2 Electrical Storage Constraints:

The model of electrical storage faces many constraints. Equations 3 and 4 refer to the charging ($P^{batt}_{t,ch}$) and discharging power ($P^{batt}_{t,dch}$) limit for the battery, which is limited by the battery's rated capacity. Also, in the model, charging is considered as taking power from the system; hence, it is depicted with a $-ve$ sign, and similarly, discharging is depicted as $+ve$. Battery is also constrained by the number of cycles it is allowed to run in a 24-hour period ($Cycle_{limit}$).

$$P^{batt}_{max,ch} \leq P^{batt}_{t,ch} \leq 0 \tag{3}$$

$$0 \leq P^{batt}_{t,dch} \leq P^{batt}_{max,dch} \tag{4}$$

$$\sum_{t=i}^{t=i+24} P^{batt}_{t,dch} = P^{batt}_{max,dch} \cdot Cycle_{limit} \tag{5}$$

3.1.3 Electrolyser Constraints

The hydrogen-producing electrolyser will also be constrained by its max capacity. Hence, the throughput for the electrolyzer (P^{PEM}_{t}), can fluctuate between 0 and (P^{PEM}_{max}). Here, the (P^{PEM}_{max}) is the rated capacity of the electrolyser.

$$0 \leq P^{PEM}_{t} \leq P^{PEM}_{max} \tag{6}$$

3.1.4 Dynamic Constraints

Apart from the static constraints, there are several dynamic constraints; these define the relation between the dynamic (temporal) variables.

$$E^{batt}_{t} = E^{batt}_{t-1} - P^{batt}_{t,ch} \cdot \eta^{batt}_{ch} - P^{batt}_{t,dch} \cdot \left(\frac{1}{\eta^{batt}_{dch}}\right) \tag{7}$$

$$P^{batt}_{t,ch} + P^{batt}_{t,dch} + P^{wind}_{t} + P^{solar}_{t} + P^{grid}_{t,in} + P^{grid}_{t,out} = P^{PEM}_{t} \tag{8}$$

$$P_t^{PEM} \cdot (\frac{1}{H_{SEC}}) = H_t \tag{9}$$

$$\frac{\sum_{t=i}^{t=i+H_{lookahead}} P_t^{PEM}}{P_{max}^{PEM} \cdot (H_{lookahead})} \geq CF_{min}^{PEM} \tag{10}$$

3.1.5 Objective Function

Here, the objective function is a minimisation function $f(x)$

$$\begin{aligned} minimize f(x) = \\ \sum_{t=i}^{t=i+lookahead} P_{t,out}^{grid} \cdot (Tarrif_t^{Feed-out}) + P_{t,in}^{grid} \cdot (Tarrif_t^{Feed-in}) \\ +P_t^{Solar} \cdot Cost_{Var}^{solar} + P_t^{Wind} \cdot Cost_{Var}^{wind} \\ +P_{t,dch}^{batt} \cdot Cost_{Var}^{Batt} - P_{t,ch}^{batt} \cdot Cost_{Var}^{Batt} \\ +P_t^{PEM} \cdot Cost_{Var}^{PEM} \end{aligned} \tag{11}$$

Based on the optimisation constraints above and the optimisation function, a rough schematic is drawn in Figure 2. Also, the result of a snapshot of the optimized dispatch schedule for a 24-hour period is provided in Figure 3.

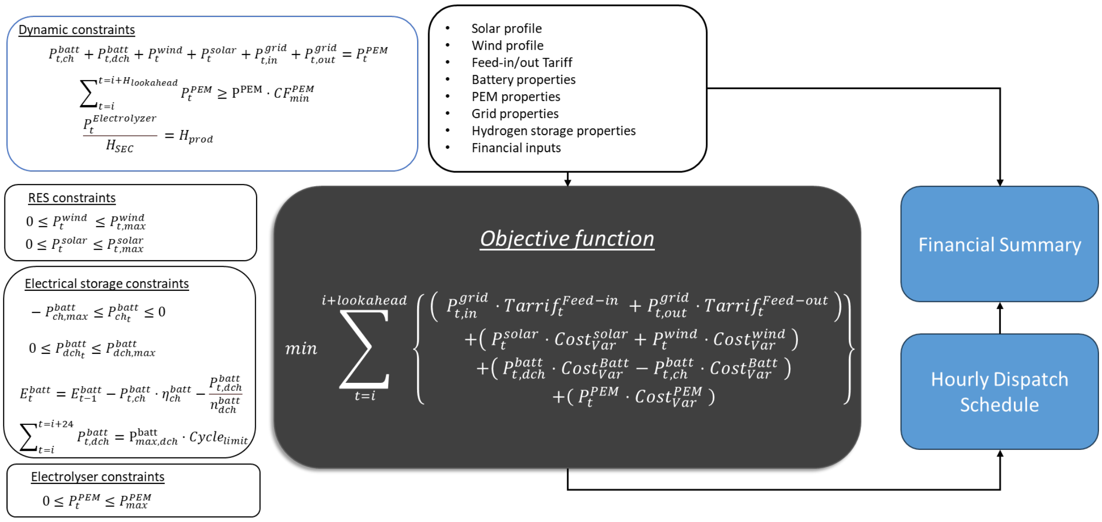

Figure 2: A brief flowchart of the optimisation model

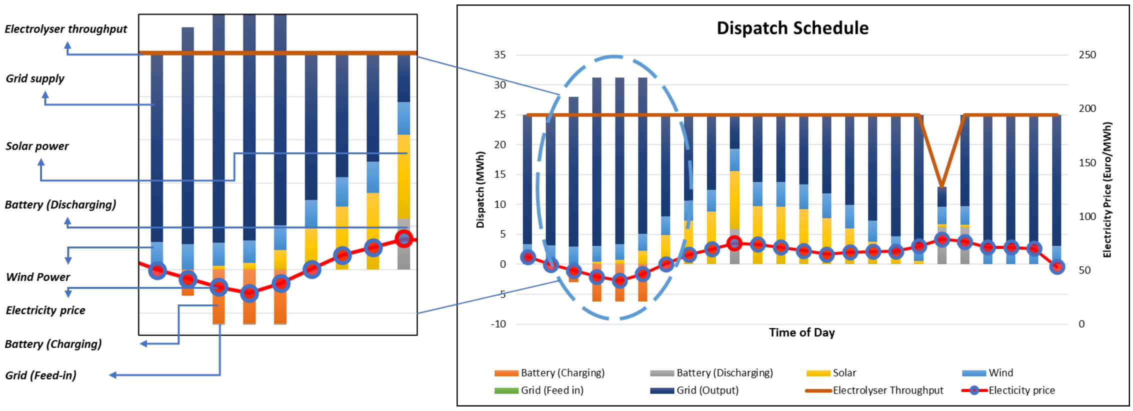

Figure 3: Example of a dispatch schedule throughout the day

3.2 Data Sets

3.2.1 Electrical price forecasting

Merit order model: The merit order model is the foundation of the current electricity pricing generation algorithm. It ranks all available electricity-generating assets based on their marginal production costs, favouring plants with lower marginal costs for electricity dispatch over those with higher costs. The market-clearing price—the point where demand meets supply—determines the electricity price for the market. Vaasaett utilises its own internal forecasting model to generate power price forecasts. An annual average price dataset can be found in the Appendix A.

There are other components involved in electricity price forecasting. All three components are below:

1. **Energy component:** Comes through merit order model
2. **Regulatory component:** Taxes and other charges, both fixed and variable
3. **Transmission component:** Charges that are brought to recover investments of TSO and DSO in building the transmission network

3.2.2 Electrical Storage and Electrolyser

The data for Electrical storage and Electrolyser is gathered from multiple sources and compiled by VaasaETT. The major values are compiled in Table 4 in Chapter 4.

3.2.3 RES Data

The renewable data set is taken from the *Joint Research Centre Data Catalogue* [4].

1. For Photovoltaic: The specific datasets taken are Solar hourly generation time series at country NUTS 1 level [5]
2. For Wind: Wind hourly generation time series at country NUTS 1 level and bidding zones [6]

The average daily profile for a typical day in each month is provided in Appendices C and D, for solar and wind, respectively, for each of the focus countries.

3.2.4 Price Data

The price data is based on VaasaETT's internal price forecasting model. Figure 4 shows the full price division for Medium voltage industrial consumers in each of the focus countries.

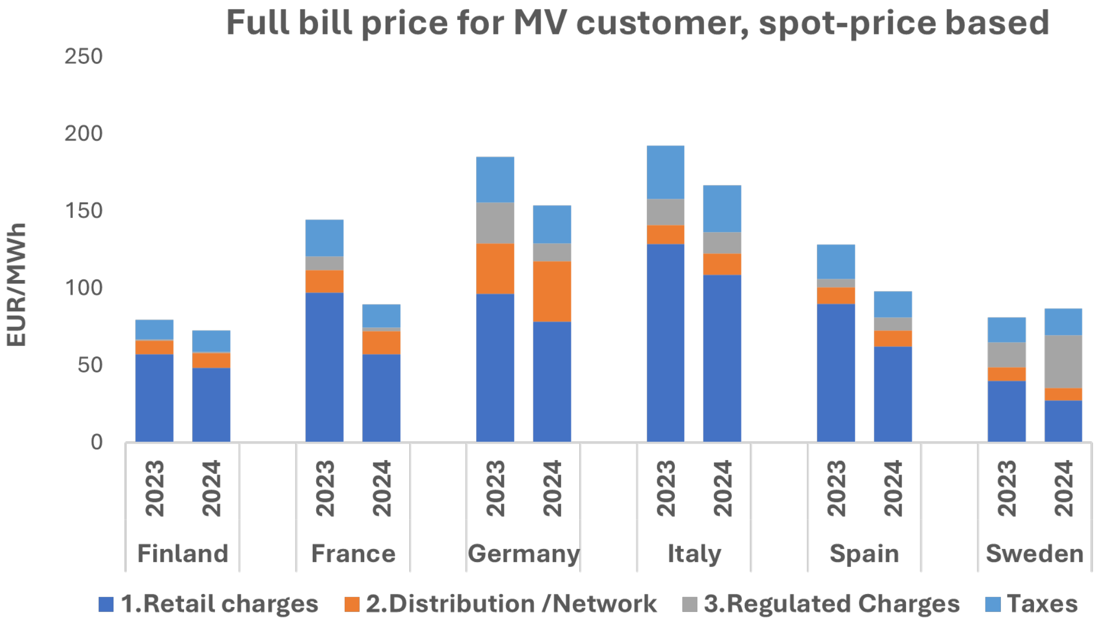

Figure 4: Historical full-bill price for Medium Voltage customer based on spot price

3.3 Financial Modelling

The project also features a simple financial model to calculate the NPV and LCOH in light of discounted future prices and revenues. Discounting means accounting for the value of future cash flows in current monetary value. The subsequent sections describe the calculation of the discounted cost of each asset.

3.3.1 Solar

The capital cost of solar $Cost^{solar}_{CAPEX}(\frac{EUR}{MW})$ and the Operations and maintenance cost is $Cost^{solar}_{O\&M}(\frac{EUR}{MW})$. The % of debt raised for the financing is denoted by $debt\%$ at an interest rate of $i(\%)$.

The net discounted lifetime cost ($NDLC^{solar}$) of a Solar asset can be described with the following components:

1. CAPEX components ($CAPEX^{solar}$):

$$CAPEX^{solar} = Cost^{solar}_{CAPEX} \cdot P^{solar}_{rated} \cdot (1 - debt\%) \tag{12}$$

2. Variable components (Var^{solar}_t):

$$Var^{solar}_t = \left(\sum_{j=0}^{j=\frac{1yr}{lookahead}} \sum_{t=j \cdot lookahead}^{t=(j+1) \cdot lookahead} Cost^{solar}_{t,Var} \cdot P^{solar}_t \right) + Cost^{solar}_{O\&M} \cdot P^{solar}_{rated} \tag{13}$$

3. Interest payments or amortized amount (A^{solar}_t):

$$A^{solar}_t = Cost^{solar}_{CAPEX} \cdot P^{solar}_{rated} \cdot (debt\%) \cdot \frac{i \cdot (1+i)^T}{(1+i)^T - 1} \tag{14}$$

The total discounted cost can be written for T years as ($NDLC^{solar}$):

$$NDLC^{solar} = CAPEX^{solar} + \sum_{t=1}^{t=T} \frac{Var^{solar}_t + A^{solar}_t}{(1+d)^t} \tag{15}$$

Similarly, discounted throughput for solar (Th^{solar}_d) can be given by:

$$Th^{solar}_d = \sum_{t=1}^{t=T} \frac{Th^{solar}_t}{(1+d)^t} \tag{16}$$

Here, Th^{solar}_t is the sum total annual solar output.
Finally levelised cost of Solar ($LCOE_{solar}$):

$$LCOE^{solar} = \frac{NDLC^{solar}}{Th^{solar}_d} \tag{17}$$

3.3.2 Wind

The financial calculation for the wind asset is similar to the solar one in the previous section. Hence, the $NDLC^{wind}$ can provided by following equation:

$$NDLC^{wind} = CAPEX^{wind} + \sum_{t=1}^{t=T} \frac{Var^{wind}_t + A^{wind}_t}{(1+d)^t} \tag{18}$$

and the LCOE for wind $LCOE^{wind}$ is provided by:

$$LCOE^{wind} = \frac{NDLC^{wind}}{Th^{wind}_d} \tag{19}$$

3.3.3 Battery

For batteries, the calculation of CAPEX and OPEX is similar to Solar and wind assets. However, the variable cost of batteries is incurred in both charging and discharging cycles. Hence,

$$Var_t^{batt} = Var_{t,ch}^{batt} + Var_{t,dch}^{batt} + Cost_{O\&M}^{batt}.P_{rated}^{batt} \tag{20}$$

So, the net discounted lifetime cost $NDLC^{batt}$ for batteries can be obtained by following equation:

$$NDLC^{batt} = CAPEX^{batt} + \sum_{t=1}^{t=T} \frac{Var_t^{batt} + A_t^{batt}}{(1+d)^t} \tag{21}$$

The Levelized cost of storage (LCOS) is difficult to estimate, because batteries are not an electricity-generating asset and hence their throughput is not defined. Also, the electricity that is used to charge the batteries is also accounted for in grid charges. Hence, the calculation of LCOS has been omitted.

3.3.4 Grid

There are several charges when connecting to the grid:

1. Variable charges: Charges which are based on energy consumption ($\frac{EUR}{MW}$), these charges are important for the optimisation of the dispatch schedule since they directly affect the optimisation function.
   (a) Spot price - These are the prices of electricity bought and sold at the Day-ahead wholesale market. The charges are based on energy consumption ($\frac{EUR}{MW}$)
   (b) Variable grid prices - Many regulatory and network charges are also based on volume of energy consumption ($\frac{EUR}{MW}$).
2. Grid charges based on connection capacity: These charges are based on the connection capacity to the grid, which are paid every year ($\frac{EUR}{MW-year}$).
3. Annual grid charges: These are fixed regulatory and network charges that are levied annually based on the connection point ($\frac{EUR}{connection\ point}$)
4. One-time connection costs: These are the costs incurred during the connection with the grid. These costs are ignored in the LCOH calculations since they make up for a small portion of the cost in the final cash flow. In most cases, the connection is already present and paid for.

There are network charges when connecting to the grid; for the counties analyzed, these charges are variable in nature, i.e., $\frac{EUR}{MWh}$, and already accounted for in the full bill. There are some fixed components in the total bills, such as components of network charges and regulated charges. These are often based on connection capacity ($\frac{EUR}{MW}$) or a fixed cost ($\frac{EUR}{yr}$). These can also be based on peak consumption as well as seasonal consumption. These charges are accounted for in the final calculation of LCOH since fixed costs don't affect the optimisation. Hence, the grid charge (C_t^{grid}) for optimisation is a combination of variable charges and spot price.

A brief example breakdown of Medium voltage ($1kV - 50kV$) grid charges in France is provided in the table 3.

	Variable Components		**Fixed Components**	
	Spot price (EUR/MWh)	**Volumetric grid charges (EUR/MWh)**	**Capacity Charges (EUR/MW/yr)**	**Fixed charges (EUR/yr)**
2018	44.89	34.85	29790.4	1225.2
2019	47.77	28.64	32227.3	1210.8
2020	38.70	24.36	35889.0	1217.0
2021	44.23	24.61	44946.4	1244.2
2022	153.15	21.02	52411.0	1047.8
2023	204.43	14.80	64832.6	910.4
2024	115.99	12.26	66465.1	951.2

Table 3: Example breakdown of a sample electricity bill in France (Source: VaasaETT forecast)

Here, no CAPEX is assumed for the grid, however, OPEX for the grid can be estimated by the fixed grid components paid annually. And the variable charges can be estimated by the difference between the grid output charge and input charges calculated based on variable components. Also, since the grid doesn't have any capital expenditure, the grid's amortization cost doesn't exist. Hence, the discounted charge of the grid can be written as the discounted variable charge (Var_d^{grid}), which is equal to:

$$NDLC^{grid} = Var_d^{grid} = \sum_{t=1}^{t=T} \frac{Var_t^{grid}}{(1+d)^t} \tag{22}$$

3.3.5 Electrolyser

The major cost component of an electrolyzer is CAPEX, and OPEX is almost negligible; hence, for practical purposes, an electrolyzer's operational and variable cost is taken to be zero. These costs are also offset by the auxiliary products the electrolyzers produce, such as heat and oxygen, which have their own separate supply chain. The electricity used by the electrolyser to produce hydrogen is already accounted for in the grid charges, hence, the net discounted lifetime cost of the electrolyzer ($NDLC^{PEM}$) can be obtained by the following equation:

$$NDLC^{PEM} = CAPEX^{PEM} + \sum_{t=1}^{t=T} \frac{Cost_{O\&M}^{PEM} + A_t^{PEM}}{(1+d)^t} \tag{23}$$

3.3.6 Levelised cost of Hydrogen Production

The levelised cost of hydrogen is the ratio of total net discounted lifetime cost of the system ($NDLC^{sys}$) and total discounted hydrogen production (H_d). The net discounted lifetime cost for the whole system can be defined as the sum of all the NLDCs of individual components.

$$NLDC^{sys} = NLDC^{solar} + NLDC^{wind} + NLDC^{batt} + NLDC^{grid} + NLDC^{PEM} \tag{24}$$

The discounted production of hydrogen can be defined as:

$$H_d = \sum_{t=1}^{t=T} \frac{H_t}{(1+d)^t} \tag{25}$$

Based on the above equations, the Levelised cost of hydrogen ($LCOH$) can be obtained by the following equation:

$$LCOH = \frac{NLDC^{sys}}{H_d} \tag{26}$$

4 Results and Discussion

4.1 Design of simulation

The experiment is designed as a Monte Carlo simulation that explores all possible scenarios to create a landscape of potential Least Cost of Hydrogen (LCOH) values, measured in EUR per kilogram of hydrogen ($\frac{EUR}{kg-of-H_2}$). For the calculations of LCOH, various assets with different parameters have been selected and simulated across a range of reasonable values. This approach allows for the estimation of LCOH across a broad spectrum of possibilities.

For simulation, the following six countries have been chosen and ranked (see Figure 5) since they represent diverse geographies and market conditions:

1. **Spain** - Represents conditions in the Iberian Peninsula
2. **Germany and France** - Represents conditions in Central Europe
3. **Italy** - Represents conditions in Southern Europe
4. **Finland & Sweden** - Represents Nordic conditions

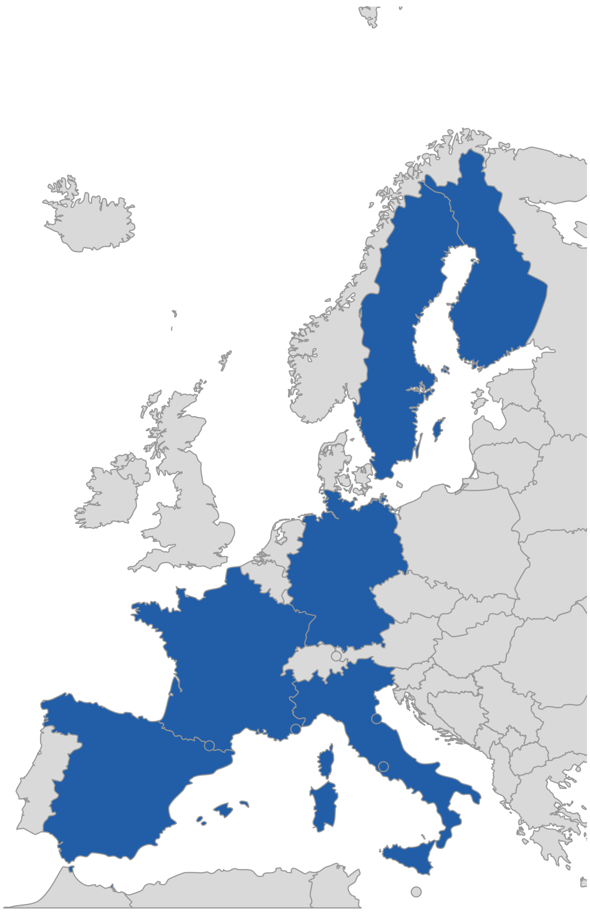

Figure 5: Focus countries for LCOH analysis within Europe

Within these geographies, several combinations of analysis were chosen with variable system sizes. A detailed list of all the combinations and simulation results is compiled in Appendix B.

However, the results of the simulation from a few key configurations are provided here, and they are divided into multiple cases:

1. Case 0: The electrolyser is running solely with the power from the grid (spot-based contract)
2. Case 1a: The electrolyser is running with a comparable Wind asset and support from the grid (5 MW electrolyser, 7.5 MW wind generation asset)
3. Case 1b: The electrolyser is running with a comparable Solar asset and support from the grid (5 MW electrolyser, 7.5 MW solar generation asset)
4. Case 2: Same case as Case 1a, but with addition of electrical storage (5MW, 4hr)

4.2 Assumptions

Some major assumptions throughout this project are:

1. The life span of all the major assets (RES - Wind & Solar, Battery, and electrolyser) is 20 years.
2. No degradation in the asset throughputs throughout their life span
3. Properties of the proton exchange membrane electrolyser are used for simulation
4. The electrolyser is running at a high capacity factor (>75%)
5. The revenue from auxiliary products (such as heat and oxygen generated) from the electrolyser is not considered
6. A fixed discounting factor and interest rate are assumed for all periods
7. The capex of all the assets is assumed to be the same for all countries
8. Debt-to-equity ratio is assumed to be 50%
9. Average RES profile for the whole country is used for calculations
10. Maximum number of battery cycles is 2 per day

Key technical inputs	**Unit**	**Value**
Electrolyser size (for all cases)	kW	5000
Wind Size (for all cases)	kW	7500
Solar Size (for all cases)	kW	7500
Battery Size	kW	5000
Specific Energy Consumption	kWh/kg H2	55
Project duration	Yr(s)	20
Customer connection level	Voltage	Medium Voltage (MV)
PEM Electrolyser CAPEX	€/kW	1000
PEM Electrolyser OPEX	€/kW/yr	20
Onshore Wind CAPEX	€/kW	1000
Onshore Wind OPEX	€/kW/yr	39
Utility Scale Solar CAPEX	€/kW	500
Utility Scale Solar OPEX	€/kW/yr	12
Li-ion Battery CAPEX (4hr)	€/kWh	300
Li-ion Battery OPEX (4hr)	€/kWh/yr	3.5
Debt to equity ratio	:	50:50
Project start	Yr	2024
Discount rate	%	3%
Interest rate	%	5%
Price Scenario	-	VaasaETT Base Scenario

Table 4: Technical assumptions for the simulation

4.3 Results & Discussion

4.3.1 Case 0

The *case 0* serves as a baseline for assessing hydrogen generation in a specific market based entirely on grid prices. In this context, the Nordic region benefits from relatively low overall grid prices, which take into account energy costs, regulatory fees, and network tariffs. This favourable pricing environment creates optimal conditions for utilising the grid directly for hydrogen production, as illustrated in Figure 6.

This insight is crucial, as the new RFNBO legislation may identify the Nordics as a green zone. This designation allows hydrogen produced from the grid within the green zone to be classified as green hydrogen [7][8].

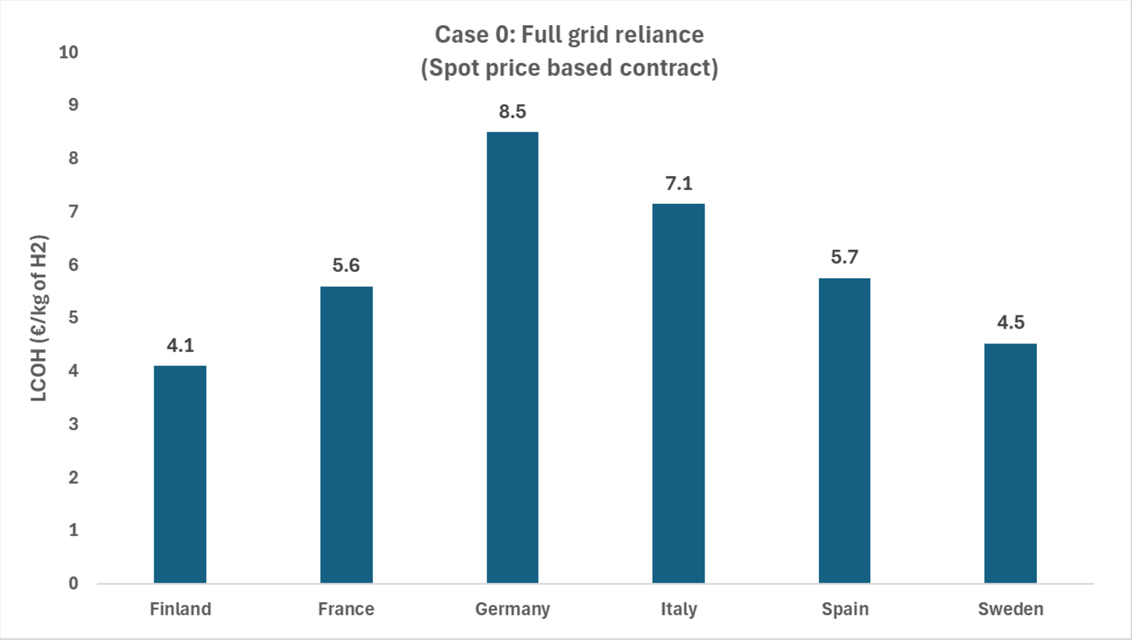

Figure 6: Hydrogen cost with full-grid reliance

Germany and Italy have high LCOH prices due to elevated grid network charges and regulated components, while France and Spain exhibit similar LCOH prices.

4.3.2 Case 1

Case 1 illustrates how renewable energy sources (RES) impact the cost of hydrogen production. Because of the intermittent nature of these sources, they cannot consistently provide enough power to keep the electrolyzer operating at a high capacity factor. As a result, the grid must supply the additional power needed. *Case 1* is further divided into *Case 1a* and *Case 1b*, which demonstrate these effects through solar and wind energy, respectively.

Case 1a: Effect of Solar asset on the Cost of hydrogen production (LCOH).

In *Case 1a* (Figure 7), the electrolyser is connected to a 7.5 MW onsite solar generation system. The solar generation varies by country, which in turn affects the Levelized Cost of Hydrogen (LCOH) differently in each location. In most countries, except the Nordic region, the introduction of solar power leads to a reduction in LCOH. In the Nordics, the Levelized Cost of Energy (LCOE) generated by solar assets is nearly equal to or slightly higher than the average grid prices. As a result, adding solar assets does not significantly impact the final LCOH in this region.

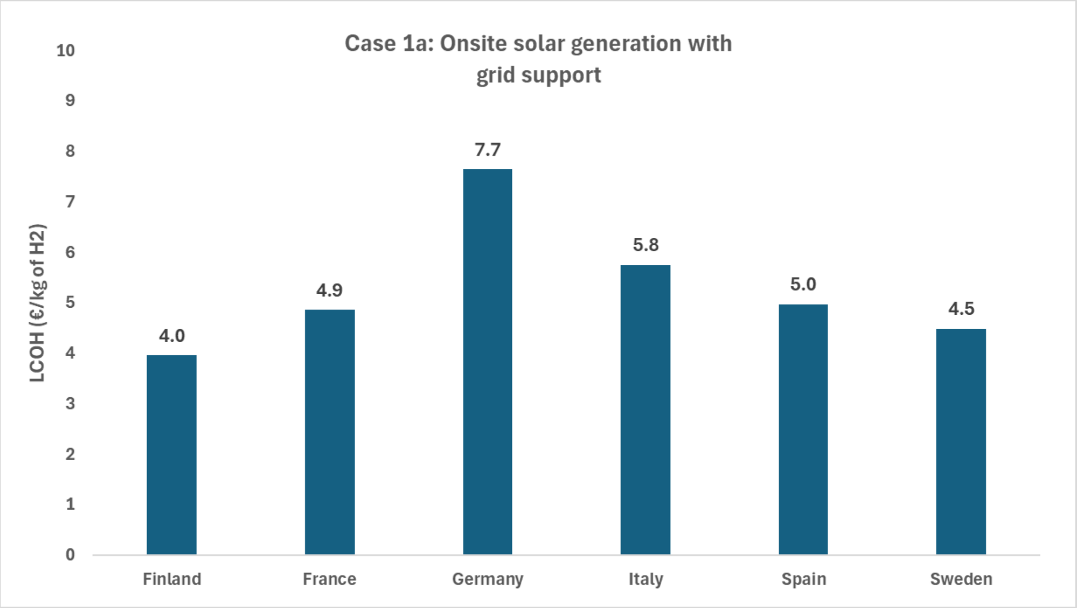

Figure 7: Onsite Solar with grid support (Spot price contract)

Figure 8 illustrates the power share from each connected resource. It is evident that, despite having a solar asset of comparable size, the plant relies significantly on the grid. This heavy reliance is attributed to the low capacity factor of the solar installation. This indicates that solar assets may need to be substantially oversized to support the majority of electrolyzer operations. Alternatively, electrolyzer operations should be flexible enough to run at high load factors during daylight hours and to decrease output during non-solar hours. Results from oversized RES assets are also provided in the Appendix B.

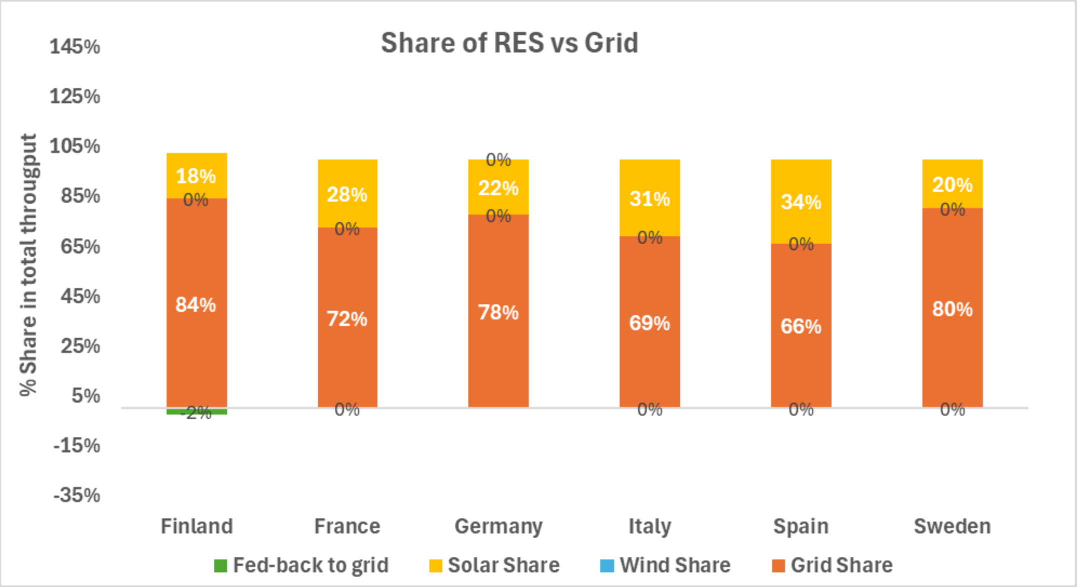

Figure 8: Share of electricity from solar asset vs Grid (Spot price contract)

Case 1b: Effect of Wind asset on the Cost of hydrogen production (LCOH).

In *Case 1a* (Figure 7), the electrolyzer is connected to a 7.5 MW on-site wind generation system (see Figure 9). The amount of wind generation varies by country, which in turn affects the Levelized Cost of Hydrogen (LCOH). In this scenario, all countries show a significant reduction in LCOH, including the Nordic countries, compared to Case 0. This reduction can be attributed to several factors:

1. Wind assets have a higher capacity factor compared to solar.
2. Wind LCOE is generally lower than the average grid prices across Europe.
3. Wind generation doesn't coincide with low price hours (compared to solar), hence it features a higher capture rate.

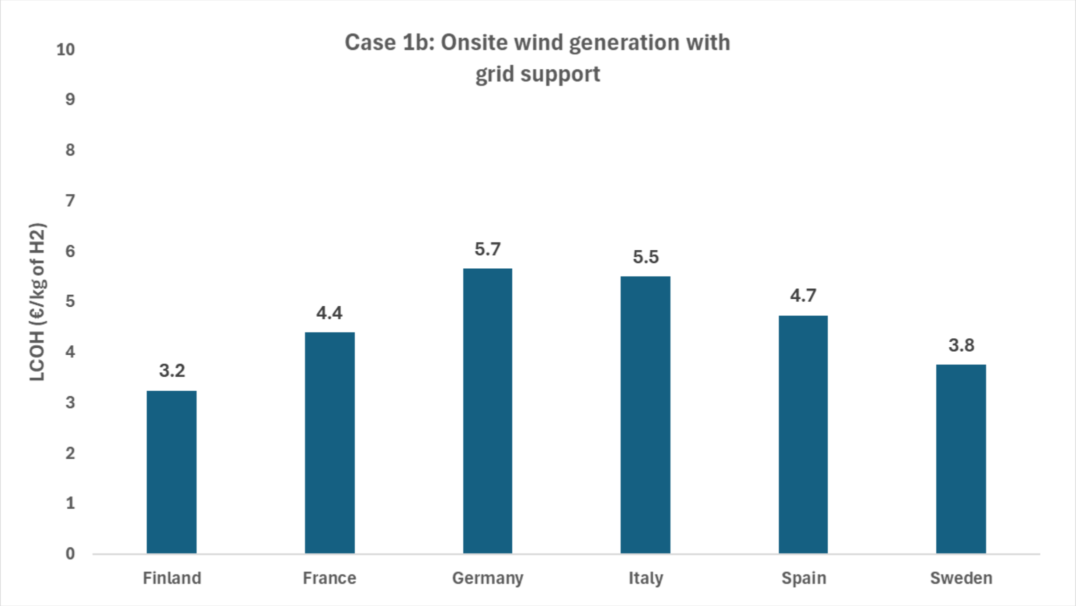

Figure 9: Onsite Wind with grid support (Spot price contract)

Figure 10 shows the contribution of different assets in Case 1b. In this scenario, the grid is crucial for maintaining a high capacity factor for the electrolyzer, although this factor is lower than that of solar assets. Additionally, there is some feedback to the grid during periods of high energy prices. To increase the proportion of wind energy in the overall mix, it is necessary to oversize the wind asset. If this is not done, the electrolyzer must operate with greater flexibility to enhance the share of renewable energy sources (RES) in total hydrogen production. The results from the oversized wind assets are compiled in Appendix B.

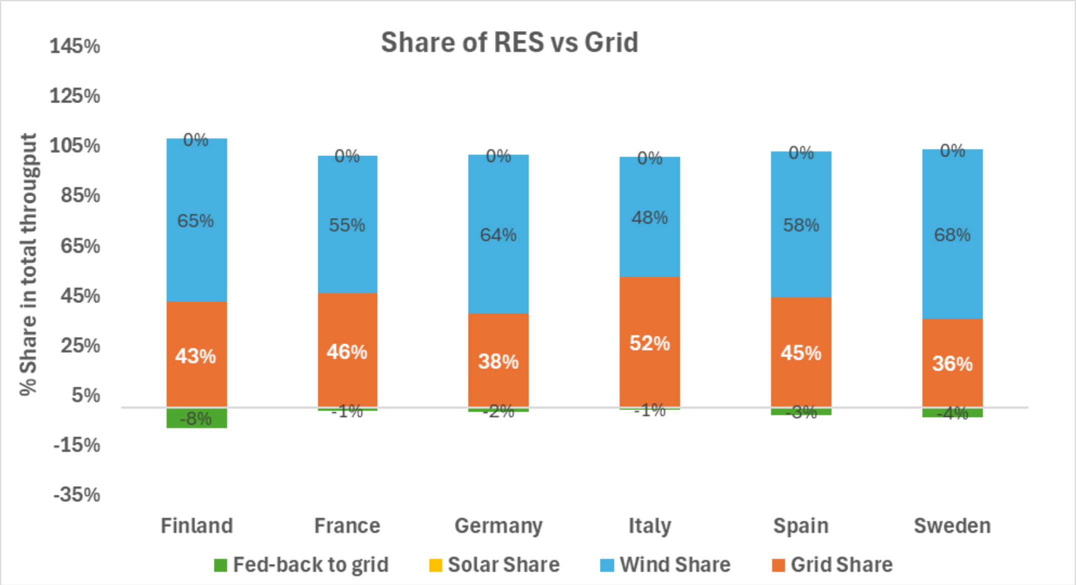

Figure 10: Share of electricity from wind asset vs Grid (Spot price contract)

4.3.3 Case 2

Case 2: Effect of electrical storage along with Wind asset on the Cost of hydrogen production (LCOH).

In this case, Figure 11 illustrates the impact of electrical storage combined with onsite wind generation. The introduction of electrical storage negatively affects the overall profitability of the hydrogen plant, resulting in an increase in the total Levelized Cost of Hydrogen (LCOH) across various countries. This decline in profitability is primarily due to high capital costs and limited opportunities for arbitrage. Additional results from other scenarios can be found in Appendix B.

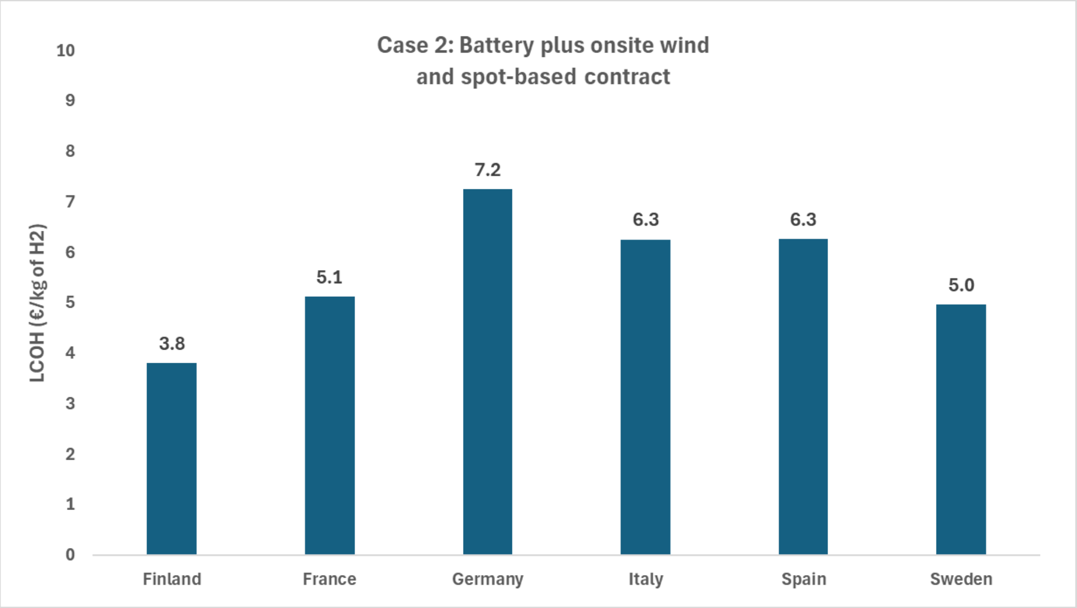

Figure 11: Onsite Wind with grid support (Spot price contract) and electrical storage

Figure 12 illustrates the share of each asset's dispatch. The inclusion of electrical storage has led to an increase in the amount of electricity fed back into the grid. This effect is particularly noticeable in Finland, where the high volatility of prices and a greater margin for arbitrage contribute to this trend.

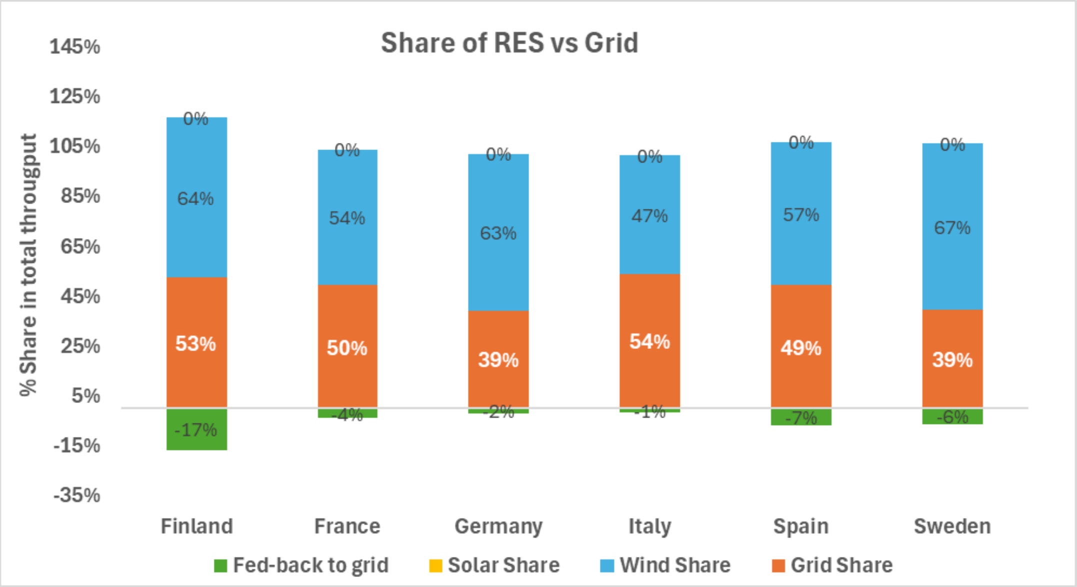

Figure 12: Share of electricity from wind asset vs Grid (Spot price contract) with an electric storage asset

4.3.4 Liquidity requirement

One of the major challenges for large projects is the issue of investment liquidity. Setting up onsite generation reduces costs compared to having a Power Purchase Agreement (PPA), but it also carries significant risks. In Figure 13, one of the most favourable Levelized Cost of Hydrogen (LCOH) scenarios from Sweden is presented. The LCOH is €3.80 per kilogram of hydrogen. However, achieving this configuration requires a total upfront investment of over six billion euros, with 50% financed through debt.

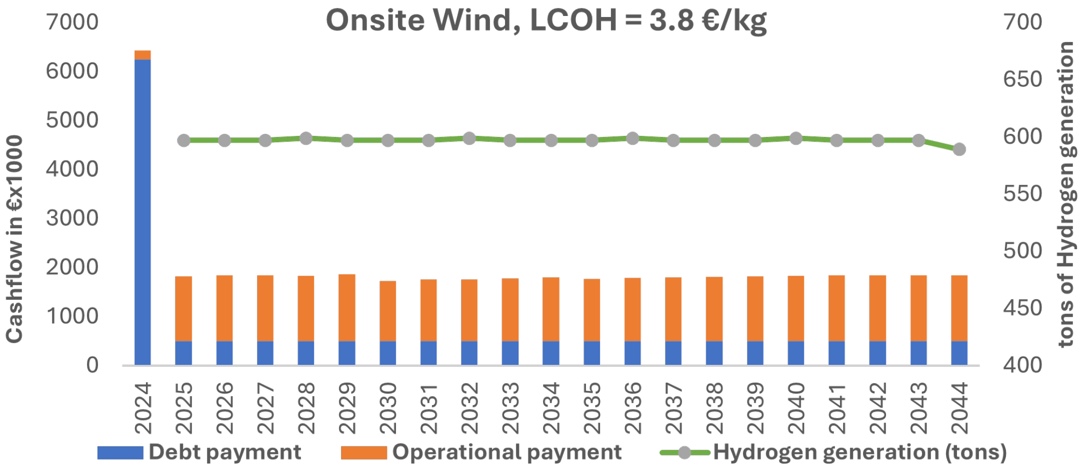

Figure 13: LCOH in Sweden, with 7.5 MW wind generation asset

5 Conclusion and Future Work

5.1 Conclusion

This thesis presents a comprehensive techno-economic analysis of green hydrogen production systems that integrate electrical energy storage and grid connectivity. By developing a mathematical optimization model based on mixed-integer linear programming (MILP), the study systematically evaluates how such systems perform under varying market conditions, technological parameters, and operational strategies. The model incorporates critical elements such as real-time electricity pricing, electrolyzer efficiency, and energy storage dynamics, enabling a realistic and data-driven assessment of economic feasibility.

The case study, supported by real-world electricity market data and renewable generation profiles, demonstrates the following:

1. The green hydrogen production is not at economic parity with grey hydrogen production if it is produced with a comparable size of RES generation.
2. It also demonstrated that coupling the hydrogen generation plants with onsite RES assets alone is not sufficient; the system will need constant grid support to run the electrolyser at a high capacity factor.
3. Flexible assets such as electrical storage systems are currently not a profitable investment for green hydrogen production due to high capital costs and low arbitrage opportunities.
4. An oversized RES system, especially wind, can bring the overall cost of hydrogen production into parity with grey hydrogen production. However, it would incur significant investment and liquidity issues.
5. The "greenness" of hydrogen will significantly depend upon the grid mix of a particular bidding zone.

The research indicates that having a large onsite renewable energy source (RES), particularly wind, in favorable market conditions can make grid-connected green hydrogen production systems economically viable. The techno-economic model developed in this study provides valuable insights for policymakers, investors, and engineers who are looking to design, assess, or implement hydrogen-based energy solutions.

5.2 Future work

Future work could enhance this model by incorporating multi-vector energy systems, policy mechanisms like carbon pricing, and uncertainty modelling to better address the unpredictable nature of renewable energy generation and electricity markets. The model is continually being developed beyond the scope of this thesis project. Current improvements include:

1. Addition of Ancillary revenue to the model - Currently, only the battery can participate in the ancillary market.

2. Addition of PPA as a source of power for the hydrogen plant - This is consistent with the upcoming RFNBO guidelines (currently under review till 2029).

Below is a brief schematic of the new model (Figure 14).

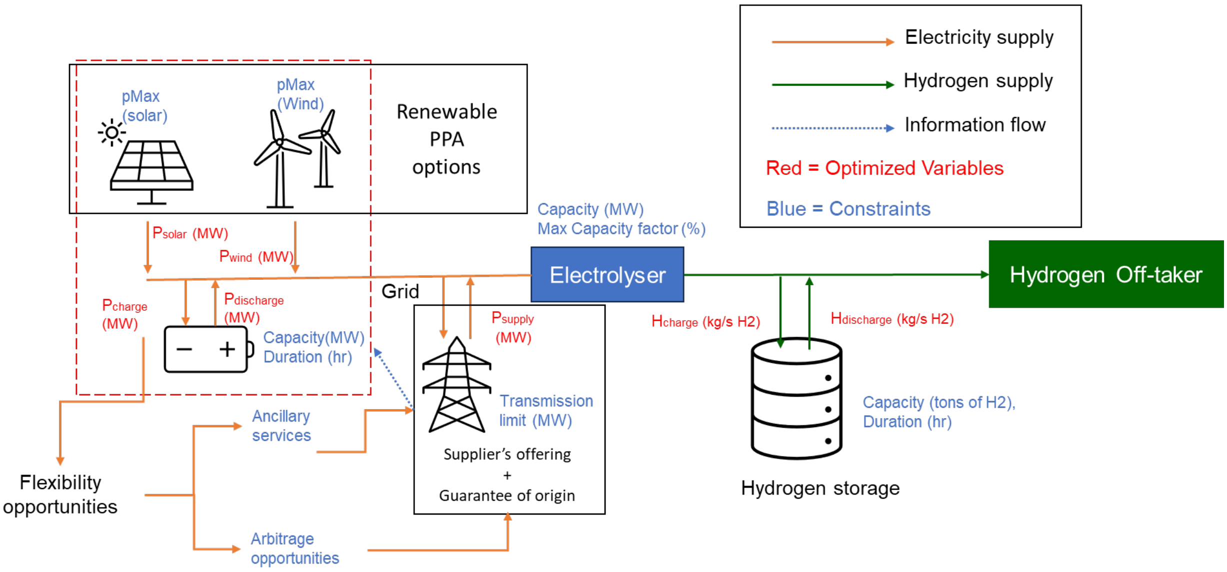

Figure 14: A graphic representation of the latest model structure

In addition to the current state of the model, future improvements are being considered. A few of them are listed below:

1. **Increased granularity**: The current optimization granularity is one hour, while the financial model granularity is one year. This can be improved to fifteen minutes and quarterly, respectively, to capture more realistic insights.

2. **Improved financial model**: The current financial model provides a basic perspective on investment and cash flow. To enhance it, a more sophisticated model is necessary to capture the complexities involved in investment decisions. An important aspect to consider is the different cost drivers in a hydrogen generation plant. Table 5 offers a comprehensive overview of the components that should be included in the financial calculation of the Levelized Cost of Hydrogen (LCOH).

Parameter	**Consideration**	**Notes**
Electrolyser	Consider	CAPEX Account for CAPEX scaling influence.
Discount rate	Consider	Also known as Weighted Average Cost of Capital (WACC).
Electricity price	Consider	Should include all charges.
Electrolyser efficiency	Consider	Specific energy consumption including auxiliary power [kWh/kgH2].
Electrolyser system lifetime	Consider	Major cost driver due to distribution of CAPEX.
Stack lifetime & replacement	Consider	Costs for stack replacement to be included in the CAPEX.
Stack degradation	Consider	Considered through average specific energy consumption.
Engineering, Procurement, Construction	Consider	Contains usually detailed planning and control, purchasing, execution of construction, installation work, and commissioning.
Buildings	Consider	Reflect cost difference between greenfield / brownfield.
Balance of Plant (BoP)	Consider	BoP typically includes power supply, water conditioning, and process utilities like pumps, process-value-measuring devices, and heat exchangers.
OPEX	Consider	Typically in the range of 1.5%–5% of CAPEX.
Compression	Maybe	Consider compression costs for system output below reference pressure.
Hydrogen quality	Maybe	Identified as a minor cost driver. Nevertheless, it is recommended to calculate with a 5.0 quality to ensure that there are no technical issues.
Water supply	Maybe	Costs are to be considered if a seawater desalination plant is required.
Electrical grid	Not consider	Assumption of an existing grid.
Contingency	Not consider	Not taken into account in most studies.
Funding	Not consider	Funding programmes are strongly influenced by political conditions and vary over time.
Properties	Not consider	Vary significantly between countries as well as urban and rural areas.
Hydrogen transport & storage	Not consider	Multiplicity of further possible applications.
By-product revenues	Not consider	Omit revenues from by-products (waste-heat, oxygen).

Table 5: Importance of cost components in the calculation of LCOH [40]

3. **Addition of auxiliary revenue stream**: The hydrogen plants also produced several byproducts, such as oxygen and heat. These byproducts can also be monetised if there is a market for them.
4. **Granular locational analysis**: The current analysis focuses on the Renewable Energy Source (RES) generation profile, which represents the average RES generation across the country. However, the analysis for Levelized Cost of Hydrogen (LCOH) can be tailored to more localised conditions. By selecting a RES profile that reflects specific local circumstances, it may enhance the profitability of hydrogen plants. This is particularly relevant because many hotspots for RES can generate significantly more energy than the national average.
5. **Effect of policies and incentives**: Various incentives from government and institutions can impact prices in a non-linear fashion; these factors should be analyzed and considered when calculating the final Levelized Cost of Hydrogen (LCOH). A recent example is the Hydrogen Bank, which serves as a financial tool to encourage private investments in the hydrogen value chain [41].
6. **More detailed technical modelling**: The current techno-economic model has several limitations. By focusing on enhancing the model and its inputs, we can achieve more accurate results. Additionally, the technical model should include a comparison of various hydrogen end products, such as gaseous hydrogen, ammonia, and methanol.
7. **Supply side modelling**: The steel industry is currently the largest consumer of hydrogen, primarily using grey hydrogen. There has been considerable emphasis on reducing the cost of hydrogen production. However, it is also important to address the infrastructure and demand for hydrogen. Therefore, conducting a modeling effort focused on the supply side of hydrogen products will provide a comprehensive perspective on the future of the hydrogen ecosystem.

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A Power forecast prices provided by VaasaETT

Future electricity prices are provided by VaasaETT Oy.

A.1 Germany

Year	Feed-in Tariff (EUR/MWh)	Feed-out Tariff (EUR/MWh)	Capacity component (EUR/MW/yr)	Fixed component (EUR/yr)
2025	126.53	80.66	80776.28	-
2026	116.26	69.29	82175.23	-
2027	109.63	61.76	83439.90	-
2028	112.14	63.56	84578.16	-
2029	137.87	69.93	85894.31	-
2030	143.47	72.45	87082.35	-
2031	140.97	68.13	88388.76	-
2032	138.82	64.63	89596.71	-
2033	140.62	65.47	90706.67	-
2034	141.78	66.27	92083.45	-
2035	143.55	67.91	93356.58	-
2036	145.19	69.32	94526.27	-
2037	146.20	70.74	95593.04	-
2038	146.87	72.15	96557.74	-
2039	147.35	73.57	97822.37	-
2040	147.29	74.99	98978.11	-
2041	144.92	74.61	100025.46	-
2042	142.39	74.23	100965.22	-
2043	139.80	73.85	101798.53	-
2044	138.31	73.87	102526.80	-

Table A1: Grid cost component breakdown in Germany

A.2 Spain

Year	Feed-in Tariff (EUR/MWh)	Feed-out Tariff (EUR/MWh)	Capacity component (EUR/MW/yr)	Fixed component (EUR/yr)
2025	79.44	65.94	69056.48	-
2026	78.09	64.16	71661.53	-
2027	73.26	58.94	76182.88	-
2028	75.36	60.23	80629.32	-
2029	78.01	62.13	84715.10	-
2030	82.48	65.78	88610.96	-
2031	77.98	61.59	89839.96	-
2032	75.50	59.08	91667.22	-
2033	77.23	60.60	93233.60	-
2034	78.27	61.47	94801.30	-
2035	79.98	62.98	96254.18	-
2036	81.63	64.28	98149.06	-
2037	83.27	65.59	99982.09	-
2038	84.91	66.89	101747.83	-
2039	85.59	67.46	102376.32	-
2040	87.09	68.76	103718.82	-
2041	86.78	68.41	104506.50	-
2042	86.45	68.06	105032.26	-
2043	86.12	67.72	105519.28	-
2044	85.10	66.88	105558.81	-

Table A2: Grid cost component breakdown in Spain

A.3 Finland

Year	Feed-in Tariff (EUR/MWh)	Feed-out Tariff (EUR/MWh)	Capacity component (EUR/MW/yr)	Fixed component (EUR/yr)
2025	61.00	52.73	2029.35	1851.93
2026	60.33	51.84	2097.24	1913.88
2027	58.61	49.91	2158.69	1969.96
2028	55.29	46.44	2214.17	2020.59
2029	60.20	50.22	2278.31	2079.12
2030	63.26	53.04	2336.41	2132.14
2031	65.64	55.26	2379.64	2171.59
2032	62.95	52.46	2416.45	2205.18
2033	65.92	53.81	2447.47	2233.50
2034	67.38	55.15	2479.39	2262.62
2035	68.83	56.49	2506.10	2286.99
2036	70.16	57.65	2548.35	2325.55
2037	71.47	58.81	2587.62	2361.39
2038	74.77	59.98	2623.99	2394.58
2039	76.10	61.14	2668.96	2435.62
2040	77.42	62.30	2710.76	2473.76
2041	77.22	61.99	2744.84	2504.86
2042	79.52	61.68	2775.67	2533.00
2043	79.30	61.37	2803.38	2558.29
2044	78.68	60.61	2844.18	2595.52

Table A3: Grid cost component breakdown in Finland

A.4 France

Year	Feed-in Tariff (EUR/MWh)	Feed-out Tariff (EUR/MWh)	Capacity component (EUR/MW/yr)	Fixed component (EUR/yr)
2025	75.39	62.41	4683.55	33000.11
2026	86.39	61.34	4871.27	45500.11
2027	84.45	58.83	5055.86	49800.12
2028	85.29	59.04	5192.60	53700.12
2029	87.96	61.23	5310.36	57700.12
2030	90.98	64.50	5202.13	61000.12
2031	89.02	63.40	4867.28	63408.45
2032	85.55	60.16	4792.22	66308.44
2033	87.60	61.72	4980.98	69208.45
2034	89.66	63.27	5177.04	72108.45
2035	91.75	64.82	5380.83	75008.46
2036	93.65	66.17	5592.61	77200.13
2037	95.54	67.51	5812.69	78400.13
2038	97.49	68.86	6041.46	79600.14
2039	99.44	70.20	6279.19	80800.14
2040	101.38	71.54	6526.25	82000.15
2041	101.66	71.18	6783.06	83158.48
2042	101.96	70.82	7049.97	84258.49
2043	102.28	70.46	7327.23	85358.50
2044	102.12	69.59	7615.39	86458.50

Table A4: Grid cost component breakdown in France

A.5 Italy

Year	Feed-in Tariff (EUR/MWh)	Feed-out Tariff (EUR/MWh)	Capacity component (EUR/MW/yr)	Fixed component (EUR/yr)
2025	138.70	111.49	4098.39	4933.87
2026	133.38	103.98	4298.05	4938.86
2027	122.53	91.43	4498.80	5023.88
2028	116.41	84.73	4700.68	5127.86
2029	112.17	79.44	5262.20	5232.02
2030	118.05	84.23	5386.00	5235.24
2031	117.72	82.58	5660.03	5242.20
2032	111.44	75.10	5837.68	5247.57
2033	110.74	72.76	6193.32	5351.51
2034	113.59	74.61	7190.36	5355.50
2035	116.31	76.46	7731.86	5359.26
2036	119.55	78.06	7953.55	5363.69
2037	121.99	79.66	8116.45	5366.96
2038	125.33	82.39	8266.63	5369.39
2039	127.57	84.01	8372.00	5370.50
2040	129.65	85.64	8522.84	5371.49
2041	129.97	85.20	8581.98	5372.20
2042	129.40	84.77	8591.39	5371.94
2043	128.87	84.33	8599.53	5372.49
2044	127.72	83.27	8606.48	5373.02

Table A5: Grid cost component breakdown in Italy

A.6 Sweden

Year	Feed-in Tariff (EUR/MWh)	Feed-out Tariff (EUR/MWh)	Capacity component (EUR/MW/yr)	Fixed component (EUR/yr)
2025	72.86	40.35	35148.87	8636.09
2026	72.79	39.66	39601.22	9730.03
2027	71.79	38.19	41342.38	10157.83
2028	69.59	35.53	42959.38	10555.13
2029	72.20	38.42	44459.09	10923.61
2030	57.85	40.58	47407.53	11648.04
2031	59.57	42.28	50167.70	12326.22
2032	57.94	40.14	52609.12	12926.07
2033	59.00	41.17	54850.08	13476.68
2034	60.06	42.19	56904.13	13981.36
2035	56.73	43.22	58128.40	14282.16
2036	57.62	44.11	59229.67	14552.74
2037	58.51	45.00	60364.08	14831.47
2038	59.39	45.89	61398.85	15085.71
2039	60.27	46.77	62338.87	15316.68
2040	61.13	47.66	63188.71	15525.48
2041	61.01	47.42	63952.66	15713.19
2042	60.85	47.19	64427.22	15829.78
2043	60.69	46.95	64820.54	15926.42
2044	60.22	46.37	65137.63	16004.33

Table A6: Grid cost component breakdown in Sweden

B The system configuration combinations

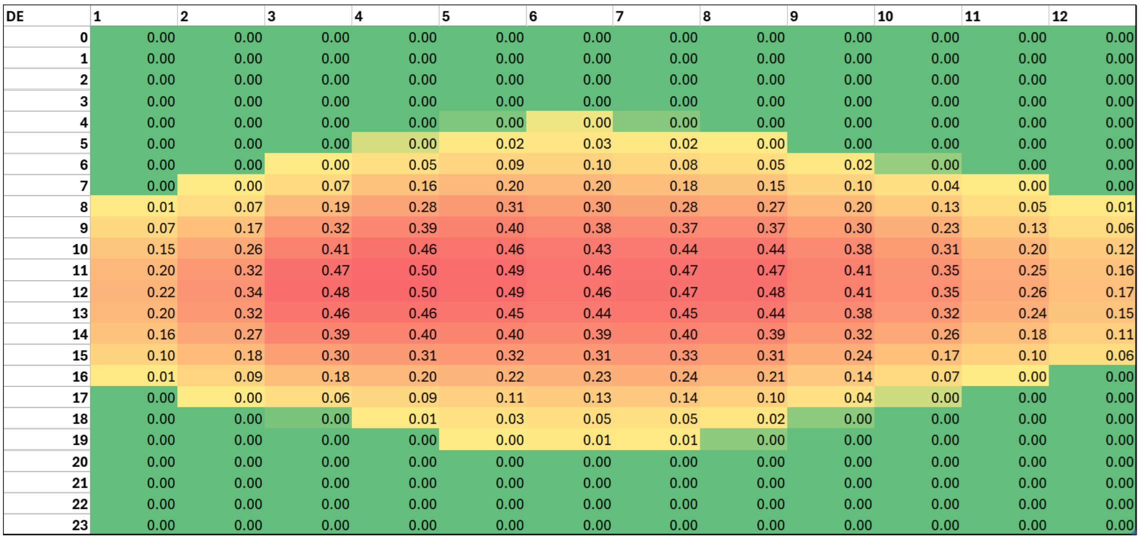
Country	Wind Capacity (MW)	Solar Capacity (MW)	Batt Capacity (MW)	Electrolyser Capacity (MW)	Solar Throughput (MWh)	Wind Throughput (MWh)	Grid purchase (MWh)	Grid feed-in (MWh)	Electrolyser throughput (MWh)	No. of Battery cycles	Hydrogen generation (Metric tons)	LCOE - Solar (EUR/MWh)	LCOE - Wind (EUR/MWh)	LCOH (EUR/kg of H2)
Germany	0	0	0	5	-	-	601.5	0.0	601.5	-	10935.8	-	-	8.5
Germany	10	0	0	5	-	510.2	142.8	-51.5	601.5	-	10935.8	-	45.7	4.9
Germany	20	0	0	5	-	1020.3	25.8	-444.7	601.5	-	10935.8	-	45.7	3.1
Germany	7.5	0	0	5	-	382.6	227.9	-9.1	601.5	-	10935.8	-	45.7	5.7
Germany	0	10	0	5	178.6	-	423.9	-1.1	601.5	-	10935.8	55.0	-	7.4
Germany	10	10	0	5	178.6	510.2	48.4	-135.7	601.5	-	10935.8	55.0	45.7	4.3
Germany	0	20	0	5	357.2	-	336.4	-92.2	601.5	-	10935.8	55.0	-	6.7
Germany	0	7.5	0	5	134.0	-	467.5	0.0	601.5	-	10935.8	55.0	-	7.7
Germany	0	0	5	5	-	-	613.7	-0.1	601.5	13366.0	10935.8	-	-	9.9
Germany	20	0	5	5	-	1020.3	31.3	-439.9	601.5	11295.3	10935.8	-	45.7	4.7
Germany	7.5	0	5	5	-	382.6	240.2	-12.8	601.5	9381.6	10935.8	-	45.7	7.2
Germany	10	10	5	5	178.6	510.2	45.3	-122.9	601.5	10649.9	10935.8	55.0	45.7	5.9
Germany	0	20	5	5	357.2	-	298.8	-42.4	601.5	13287.4	10935.8	55.0	-	8.1
Spain	0	0	0	5	-	-	656.9	0.0	656.9	-	11943.8	-	-	5.7
Spain	10	0	0	5	-	509.3	193.7	-46.1	656.9	-	11943.8	-	45.8	4.4
Spain	20	0	0	5	-	1018.7	25.4	-387.1	656.9	-	11943.8	-	45.8	3.4
Spain	7.5	0	0	5	-	382.0	292.7	-17.8	656.9	-	11943.8	-	45.8	4.7
Spain	0	10	0	5	296.4	-	378.2	-17.7	656.9	-	11943.8	33.3	-	4.7
Spain	10	10	0	5	296.4	509.3	69.2	-218.1	656.9	-	11943.8	33.3	45.8	3.6
Spain	0	20	0	5	592.9	-	307.6	-243.6	656.9	-	11943.8	33.3	-	4.0
Spain	0	7.5	0	5	222.3	-	434.6	0.0	656.9	-	11943.8	33.3	-	5.0
Spain	0	0	5	5	-	-	674.7	-6.4	656.9	12666.4	11943.8	-	-	7.3
Spain	20	0	5	5	-	1018.7	40.1	-391.4	656.9	11509.7	11943.8	-	45.8	4.9
Spain	7.5	0	5	5	-	382.0	328.8	-45.3	656.9	9417.3	11943.8	-	45.8	6.3
Spain	10	10	5	5	296.4	509.3	69.9	-206.4	656.9	13638.3	11943.8	33.3	45.8	5.1
Spain	0	20	5	5	592.9	-	256.9	-179.6	656.9	14590.0	11943.8	33.3	-	5.4
Finland	0	0	0	5	-	-	656.9	0.0	656.9	-	11943.8	-	-	4.1
Finland	10	0	0	5	-	572.9	192.0	-108.0	656.9	-	11943.8	-	40.8	3.0
Finland	20	0	0	5	-	1145.9	44.4	-533.4	656.9	-	11943.8	-	40.8	2.1
Finland	7.5	0	0	5	-	429.7	279.6	-52.4	656.9	-	11943.8	-	40.8	3.2
Finland	0	10	0	5	159.1	-	522.8	-24.9	656.9	-	11943.8	61.7	-	3.9
Finland	10	10	0	5	159.1	572.9	126.2	-201.3	656.9	-	11943.8	61.7	40.8	2.9
Finland	0	20	0	5	318.2	-	452.0	-113.3	656.9	-	11943.8	61.7	-	3.8
Finland	0	7.5	0	5	119.3	-	553.1	-15.5	656.9	-	11943.8	61.7	-	4.0
Finland	0	0	5	5	-	-	702.2	-32.0	656.9	14598.0	11943.8	-	-	4.6
Finland	20	0	5	5	-	1145.9	82.0	-557.7	656.9	14597.4	11943.8	-	40.8	2.7
Finland	7.5	0	5	5	-	429.7	352.3	-111.9	656.9	14593.6	11943.8	-	40.8	3.8
Finland	10	10	5	5	159.1	572.9	204.6	-266.5	656.9	14597.8	11943.8	61.7	40.8	3.4
Finland	0	20	5	5	318.2	-	517.0	-165.0	656.9	14598.0	11943.8	61.7	-	4.4

Table B1: Compiled results from simulation of different configuration in each countries

Country	Wind Capacity (MW)	Solar Capacity (MW)	Batt Capacity (MW)	Electrolyser Capacity (MW)	Solar Throughput (MWh)	Wind Throughput (MWh)	Grid purchase (MWh)	Grid feed-in (MWh)	Electrolyser throughput (MWh)	No. of Battery cycles	Hydrogen generation (Metric tons)	LCOE - Solar (EUR/MWh)	LCOE - Wind (EUR/MWh)	LCOH (EUR/kg of H2)
France	0	0	0	5	-	-	656.9	0.0	656.9	-	11943.8	-	-	5.6
France	10	0	0	5	-	484.7	207.4	-35.2	656.9	-	11943.8	-	48.0	4.0
France	20	0	0	5	-	969.3	41.4	-353.8	656.9	-	11943.8	-	48.0	3.0
France	7.5	0	0	5	-	363.5	301.7	-8.3	656.9	-	11943.8	-	48.0	4.4
France	0	10	0	5	242.1	-	417.0	-2.2	656.9	-	11943.8	40.7	-	4.6
France	10	10	0	5	242.1	484.7	81.9	-151.7	656.9	-	11943.8	40.7	48.0	3.3
France	0	20	0	5	484.2	-	315.9	-143.1	656.9	-	11943.8	40.7	-	3.9
France	0	7.5	0	5	181.6	-	475.4	-0.1	656.9	-	11943.8	40.7	-	4.9
France	0	0	5	5	-	-	673.1	-2.9	656.9	14595.7	11943.8	-	-	6.3
France	20	0	5	5	-	969.3	61.8	-363.3	656.9	11993.7	11943.8	-	48.0	3.7
France	7.5	0	5	5	-	363.5	331.2	-26.0	656.9	13001.7	11943.8	-	48.0	5.1
France	10	10	5	5	242.1	484.7	107.4	-165.6	656.9	12813.5	11943.8	40.7	48.0	4.0
France	0	20	5	5	484.2	-	284.4	-98.6	656.9	14426.2	11943.8	40.7	-	4.6
Italy	0	0	0	5	-	-	656.9	0.0	656.9	-	11943.8	-	-	7.1
Italy	10	0	0	5	-	421.3	254.2	-18.5	656.9	-	11943.8	-	55.0	5.0
Italy	20	0	0	5	-	842.5	71.4	-257.0	656.9	-	11943.8	-	55.0	3.4
Italy	7.5	0	0	5	-	315.9	344.4	-3.45	656.9	-	11943.8	-	55.0	5.5
Italy	0	10	0	5	271.7	-	395.7	-10.4	656.9	-	11943.8	36.3	-	5.3
Italy	10	10	0	5	271.7	421.3	102.6	-138.6	656.9	-	11943.8	36.3	55.0	3.5
Italy	0	20	0	5	543.3	-	316.9	-203.3	656.9	-	11943.8	36.3	-	4.0
Italy	0	7.5	0	5	203.7	-	453.2	0.0	656.9	-	11943.8	36.3	-	5.8
Italy	0	0	5	5	-	-	671.0	-1.4	656.9	13956.1	11943.8	-	-	7.9
Italy	20	0	5	5	-	842.5	80.9	-257.3	656.9	10122.5	11943.8	-	55.0	4.1
Italy	7.5	0	5	5	-	315.9	359.9	-9.3	656.9	10623.3	11943.8	-	55.0	6.3
Italy	10	10	5	5	271.7	421.3	88.0	-112.5	656.9	12654.2	11943.8	36.3	55.0	4.2
Italy	0	20	5	5	543.3	-	258.4	-131.6	656.9	14545.6	11943.8	36.3	-	4.7
Sweden	0	0	0	5	-	-	656.9	0.0	656.9	-	11943.8	-	-	4.5
Sweden	10	0	0	5	-	593.2	144.4	-80.7	656.9	-	11943.8	-	39.5	3.6
Sweden	20	0	0	5	-	1186.5	19.0	-548.6	656.9	-	11943.8	-	39.5	3.2
Sweden	7.5	0	0	5	-	444.9	235.1	-23.1	656.9	-	11943.8	-	39.5	3.8
Sweden	0	10	0	5	172.4	-	485.2	-0.7	656.9	-	11943.8	57.0	-	4.5
Sweden	10	10	0	5	172.4	593.2	53.5	-162.3	656.9	-	11943.8	57.0	39.5	3.6
Sweden	0	20	0	5	344.9	-	393.3	-81.3	656.9	-	11943.8	57.0	-	4.6
Sweden	0	7.5	0	5	129.3	-	527.6	0.0	656.9	-	11943.8	57.0	-	4.5
Sweden	0	0	5	5	-	-	672.4	-3.0	656.9	13794.0	11943.8	-	-	5.7
Sweden	20	0	5	5	-	1186.5	26.0	-544.8	656.9	11922.2	11943.8	-	39.5	4.4
Sweden	7.5	0	5	5	-	444.9	262.1	-41.8	656.9	9189.8	11943.8	-	39.5	5.0
Sweden	10	10	5	5	172.4	593.2	67.0	-166.3	656.9	10470.3	11943.8	57.0	39.5	4.8
Sweden	0	20	5	5	344.9	-	372.9	-48.2	656.9	13983.3	11943.8	57.0	-	5.7

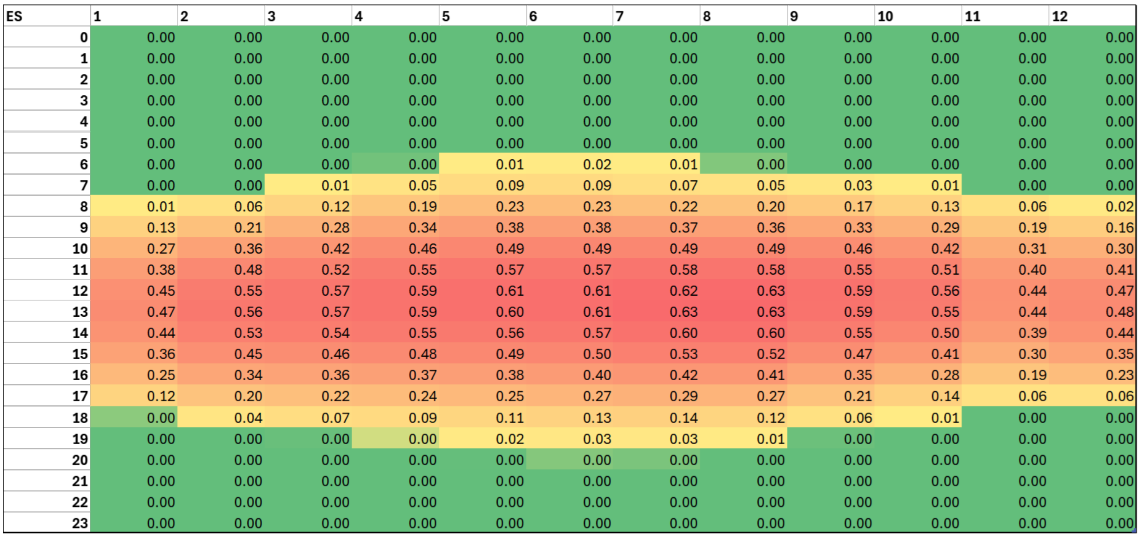
Table B2: Compiled results from simulation of different configuration in each countries

C Solar profile



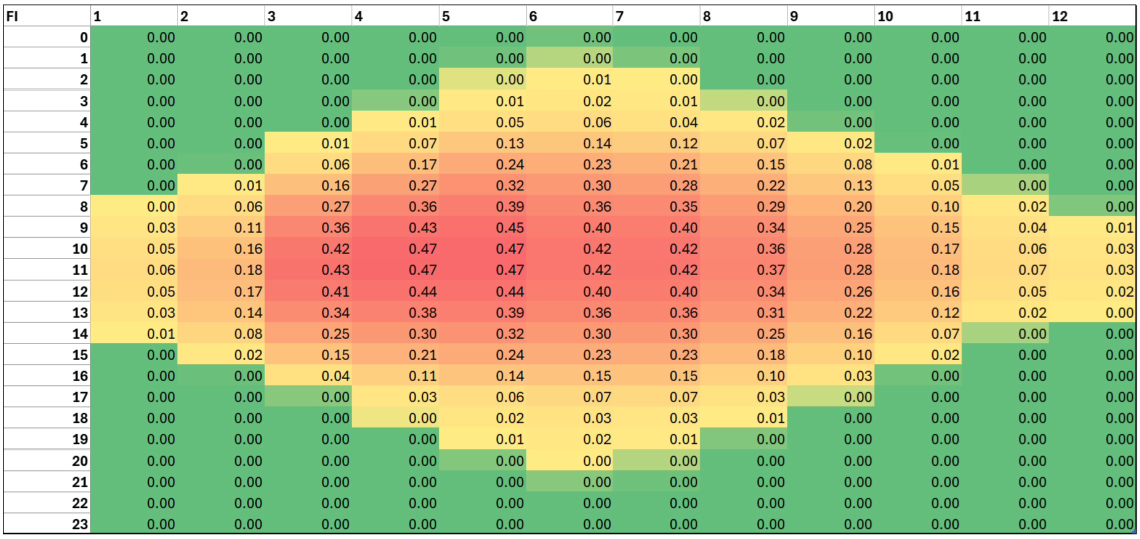
DE	1	2	3	4	5	6	7	8	9	10	11	12
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.02	0.03	0.02	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.05	0.09	0.10	0.08	0.05	0.02	0.00	0.00	0.00
7	0.00	0.00	0.07	0.16	0.20	0.20	0.18	0.15	0.10	0.04	0.00	0.00
8	0.01	0.07	0.19	0.28	0.31	0.30	0.28	0.27	0.20	0.13	0.05	0.01
9	0.07	0.17	0.32	0.39	0.40	0.38	0.37	0.37	0.30	0.23	0.13	0.06
10	0.15	0.26	0.41	0.46	0.46	0.43	0.44	0.44	0.38	0.31	0.20	0.12
11	0.20	0.32	0.47	0.50	0.49	0.46	0.47	0.47	0.41	0.35	0.25	0.16
12	0.22	0.34	0.48	0.50	0.49	0.46	0.47	0.48	0.41	0.35	0.26	0.17
13	0.20	0.32	0.46	0.46	0.45	0.44	0.45	0.44	0.38	0.32	0.24	0.15
14	0.16	0.27	0.39	0.40	0.40	0.39	0.40	0.39	0.32	0.26	0.18	0.11
15	0.10	0.18	0.30	0.31	0.32	0.31	0.33	0.31	0.24	0.17	0.10	0.06
16	0.01	0.09	0.18	0.20	0.22	0.23	0.24	0.21	0.14	0.07	0.00	0.00
17	0.00	0.00	0.06	0.09	0.11	0.13	0.14	0.10	0.04	0.00	0.00	0.00
18	0.00	0.00	0.00	0.01	0.03	0.05	0.05	0.02	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure C1: A 24x12 average profile for solar generation (MWh generated per MW installed) in Germany



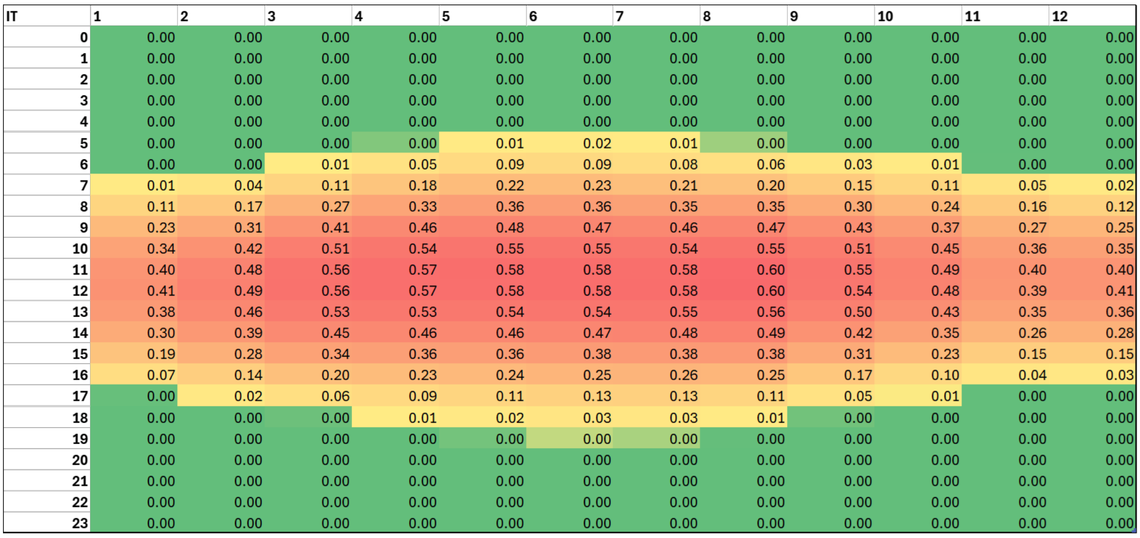
ES	1	2	3	4	5	6	7	8	9	10	11	12
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.01	0.05	0.09	0.09	0.07	0.05	0.03	0.01	0.00	0.00
8	0.01	0.06	0.12	0.19	0.23	0.23	0.22	0.20	0.17	0.13	0.06	0.02
9	0.13	0.21	0.28	0.34	0.38	0.38	0.37	0.36	0.33	0.29	0.19	0.16
10	0.27	0.36	0.42	0.46	0.49	0.49	0.49	0.49	0.46	0.42	0.31	0.30
11	0.38	0.48	0.52	0.55	0.57	0.57	0.58	0.58	0.55	0.51	0.40	0.41
12	0.45	0.55	0.57	0.59	0.61	0.61	0.62	0.63	0.59	0.56	0.44	0.47
13	0.47	0.56	0.57	0.59	0.60	0.61	0.63	0.63	0.59	0.55	0.44	0.48
14	0.44	0.53	0.54	0.55	0.56	0.57	0.60	0.60	0.55	0.50	0.39	0.44
15	0.36	0.45	0.46	0.48	0.49	0.50	0.53	0.52	0.47	0.41	0.30	0.35
16	0.25	0.34	0.36	0.37	0.38	0.40	0.42	0.41	0.35	0.28	0.19	0.23
17	0.12	0.20	0.22	0.24	0.25	0.27	0.29	0.27	0.21	0.14	0.06	0.06
18	0.00	0.04	0.07	0.09	0.11	0.13	0.14	0.12	0.06	0.01	0.00	0.00
19	0.00	0.00	0.00	0.00	0.02	0.03	0.03	0.01	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure C2: A 24x12 average profile for solar generation (MWh generated per MW installed) in Spain



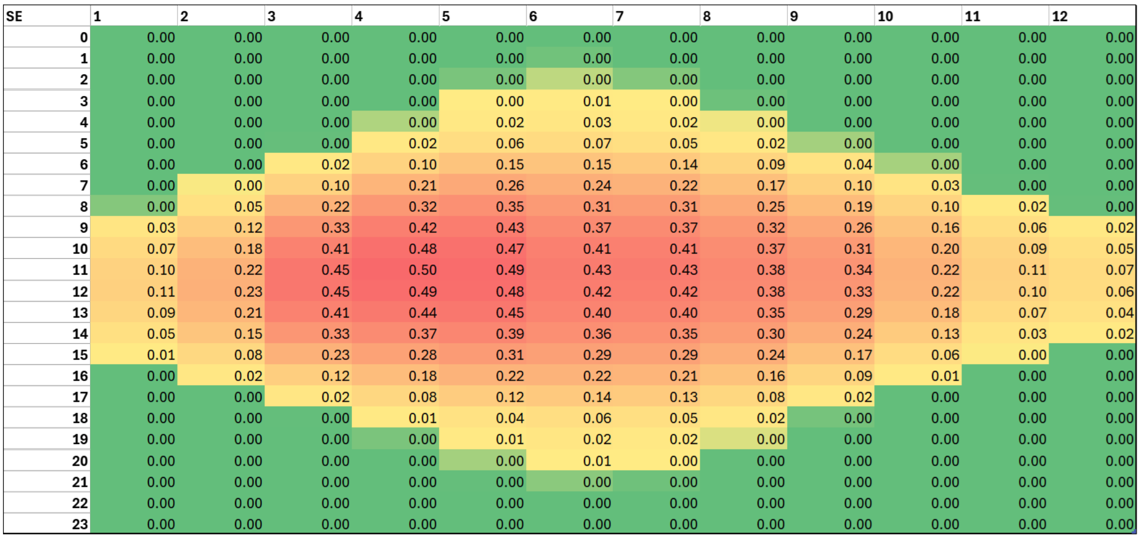
FI	1	2	3	4	5	6	7	8	9	10	11	12
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.01	0.05	0.06	0.04	0.02	0.00	0.00	0.00	0.00
5	0.00	0.00	0.01	0.07	0.13	0.14	0.12	0.07	0.02	0.00	0.00	0.00
6	0.00	0.00	0.06	0.17	0.24	0.23	0.21	0.15	0.08	0.01	0.00	0.00
7	0.00	0.01	0.16	0.27	0.32	0.30	0.28	0.22	0.13	0.05	0.00	0.00
8	0.00	0.06	0.27	0.36	0.39	0.36	0.35	0.29	0.20	0.10	0.02	0.00
9	0.03	0.11	0.36	0.43	0.45	0.40	0.40	0.34	0.25	0.15	0.04	0.01
10	0.05	0.16	0.42	0.47	0.47	0.42	0.42	0.36	0.28	0.17	0.06	0.03
11	0.06	0.18	0.43	0.47	0.47	0.42	0.42	0.37	0.28	0.18	0.07	0.03
12	0.05	0.17	0.41	0.44	0.44	0.40	0.40	0.34	0.26	0.16	0.05	0.02
13	0.03	0.14	0.34	0.38	0.39	0.36	0.36	0.31	0.22	0.12	0.02	0.00
14	0.01	0.08	0.25	0.30	0.32	0.30	0.30	0.25	0.16	0.07	0.00	0.00
15	0.00	0.02	0.15	0.21	0.24	0.23	0.23	0.18	0.10	0.02	0.00	0.00
16	0.00	0.00	0.04	0.11	0.14	0.15	0.15	0.10	0.03	0.00	0.00	0.00
17	0.00	0.00	0.00	0.03	0.06	0.07	0.07	0.03	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.02	0.03	0.03	0.01	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure C3: A 24x12 average profile for solar generation (MWh generated per MW installed) in Finland



IT	1	2	3	4	5	6	7	8	9	10	11	12
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.01	0.05	0.09	0.09	0.08	0.06	0.03	0.01	0.00	0.00
7	0.01	0.04	0.11	0.18	0.22	0.23	0.21	0.20	0.15	0.11	0.05	0.02
8	0.11	0.17	0.27	0.33	0.36	0.36	0.35	0.35	0.30	0.24	0.16	0.12
9	0.23	0.31	0.41	0.46	0.48	0.47	0.46	0.47	0.43	0.37	0.27	0.25
10	0.34	0.42	0.51	0.54	0.55	0.55	0.54	0.55	0.51	0.45	0.36	0.35
11	0.40	0.48	0.56	0.57	0.58	0.58	0.58	0.60	0.55	0.49	0.40	0.40
12	0.41	0.49	0.56	0.57	0.58	0.58	0.58	0.60	0.54	0.48	0.39	0.41
13	0.38	0.46	0.53	0.53	0.54	0.54	0.55	0.56	0.50	0.43	0.35	0.36
14	0.30	0.39	0.45	0.46	0.46	0.47	0.48	0.49	0.42	0.35	0.26	0.28
15	0.19	0.28	0.34	0.36	0.36	0.38	0.38	0.38	0.31	0.23	0.15	0.15
16	0.07	0.14	0.20	0.23	0.24	0.25	0.26	0.25	0.17	0.10	0.04	0.03
17	0.00	0.02	0.06	0.09	0.11	0.13	0.13	0.11	0.05	0.01	0.00	0.00
18	0.00	0.00	0.00	0.01	0.02	0.03	0.03	0.01	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

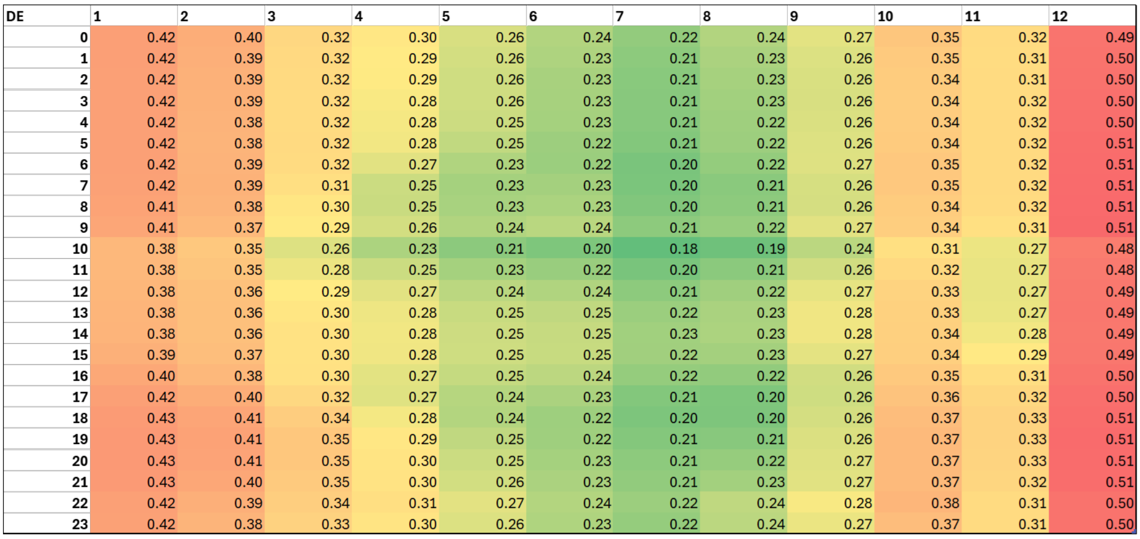
Figure C4: A 24x12 average profile for solar generation (MWh generated per MW installed) in Italy



SE	1	2	3	4	5	6	7	8	9	10	11	12
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.02	0.03	0.02	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.02	0.06	0.07	0.05	0.02	0.00	0.00	0.00	0.00
6	0.00	0.00	0.02	0.10	0.15	0.15	0.14	0.09	0.04	0.00	0.00	0.00
7	0.00	0.00	0.10	0.21	0.26	0.24	0.22	0.17	0.10	0.03	0.00	0.00
8	0.00	0.05	0.22	0.32	0.35	0.31	0.31	0.25	0.19	0.10	0.02	0.00
9	0.03	0.12	0.33	0.42	0.43	0.37	0.37	0.32	0.26	0.16	0.06	0.02
10	0.07	0.18	0.41	0.48	0.47	0.41	0.41	0.37	0.31	0.20	0.09	0.05
11	0.10	0.22	0.45	0.50	0.49	0.43	0.43	0.38	0.34	0.22	0.11	0.07
12	0.11	0.23	0.45	0.49	0.48	0.42	0.42	0.38	0.33	0.22	0.10	0.06
13	0.09	0.21	0.41	0.44	0.45	0.40	0.40	0.35	0.29	0.18	0.07	0.04
14	0.05	0.15	0.33	0.37	0.39	0.36	0.35	0.30	0.24	0.13	0.03	0.02
15	0.01	0.08	0.23	0.28	0.31	0.29	0.29	0.24	0.17	0.06	0.00	0.00
16	0.00	0.02	0.12	0.18	0.22	0.22	0.21	0.16	0.09	0.01	0.00	0.00
17	0.00	0.00	0.02	0.08	0.12	0.14	0.13	0.08	0.02	0.00	0.00	0.00
18	0.00	0.00	0.00	0.01	0.04	0.06	0.05	0.02	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

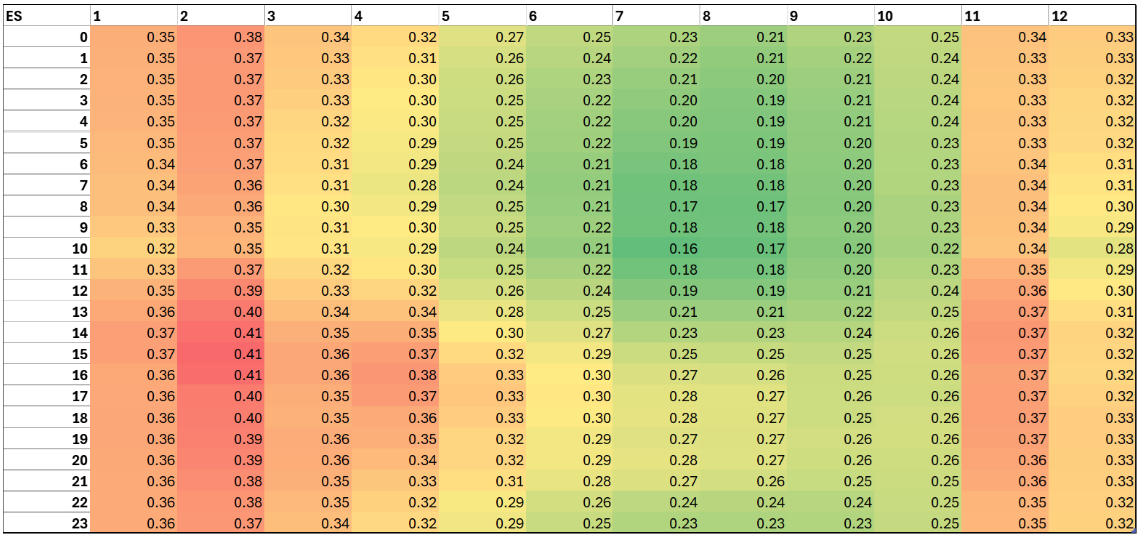
Figure C5: A 24x12 average profile for solar generation (MWh generated per MW installed) in Sweden

D Wind profile



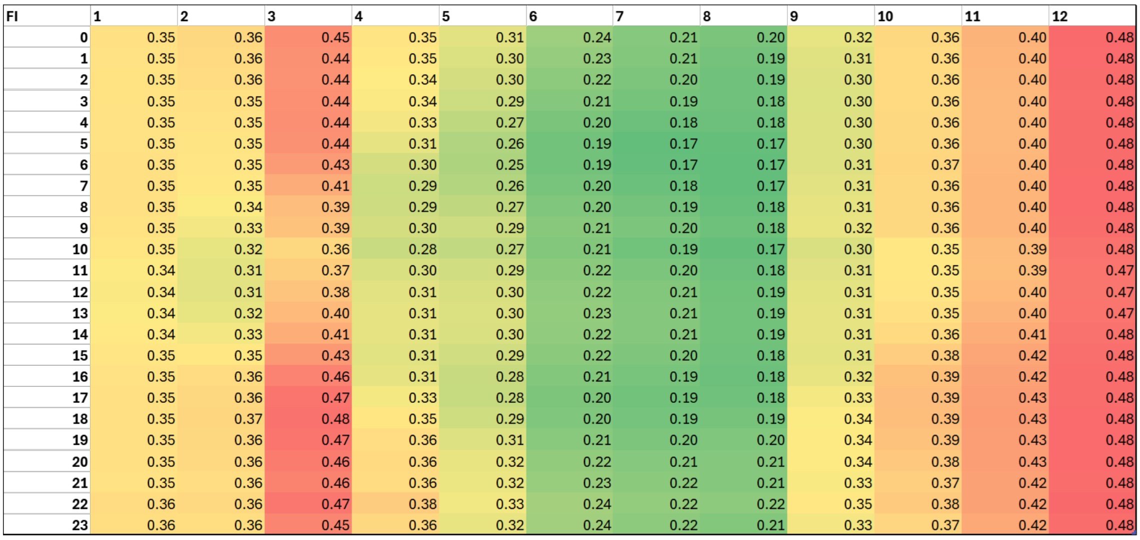
DE	1	2	3	4	5	6	7	8	9	10	11	12
0	0.42	0.40	0.32	0.30	0.26	0.24	0.22	0.24	0.27	0.35	0.32	0.49
1	0.42	0.39	0.32	0.29	0.26	0.23	0.21	0.23	0.26	0.35	0.31	0.50
2	0.42	0.39	0.32	0.29	0.26	0.23	0.21	0.23	0.26	0.34	0.31	0.50
3	0.42	0.39	0.32	0.28	0.26	0.23	0.21	0.23	0.26	0.34	0.32	0.50
4	0.42	0.38	0.32	0.28	0.25	0.23	0.21	0.22	0.26	0.34	0.32	0.50
5	0.42	0.38	0.32	0.28	0.25	0.22	0.21	0.22	0.26	0.34	0.32	0.51
6	0.42	0.39	0.32	0.27	0.23	0.22	0.20	0.22	0.27	0.35	0.32	0.51
7	0.42	0.39	0.31	0.25	0.23	0.23	0.20	0.21	0.26	0.35	0.32	0.51
8	0.41	0.38	0.30	0.25	0.23	0.23	0.20	0.21	0.26	0.34	0.32	0.51
9	0.41	0.37	0.29	0.26	0.24	0.24	0.21	0.22	0.27	0.34	0.31	0.51
10	0.38	0.35	0.26	0.23	0.21	0.20	0.18	0.19	0.24	0.31	0.27	0.48
11	0.38	0.35	0.28	0.25	0.23	0.22	0.20	0.21	0.26	0.32	0.27	0.48
12	0.38	0.36	0.29	0.27	0.24	0.24	0.21	0.22	0.27	0.33	0.27	0.49
13	0.38	0.36	0.30	0.28	0.25	0.25	0.22	0.23	0.28	0.33	0.27	0.49
14	0.38	0.36	0.30	0.28	0.25	0.25	0.23	0.23	0.28	0.34	0.28	0.49
15	0.39	0.37	0.30	0.28	0.25	0.25	0.22	0.23	0.27	0.34	0.29	0.49
16	0.40	0.38	0.30	0.27	0.25	0.24	0.22	0.22	0.26	0.35	0.31	0.50
17	0.42	0.40	0.32	0.27	0.24	0.23	0.21	0.20	0.26	0.36	0.32	0.50
18	0.43	0.41	0.34	0.28	0.24	0.22	0.20	0.20	0.26	0.37	0.33	0.51
19	0.43	0.41	0.35	0.29	0.25	0.22	0.21	0.21	0.26	0.37	0.33	0.51
20	0.43	0.41	0.35	0.30	0.25	0.23	0.21	0.22	0.27	0.37	0.33	0.51
21	0.43	0.40	0.35	0.30	0.26	0.23	0.21	0.23	0.27	0.37	0.32	0.51
22	0.42	0.39	0.34	0.31	0.27	0.24	0.22	0.24	0.28	0.38	0.31	0.50
23	0.42	0.38	0.33	0.30	0.26	0.23	0.22	0.24	0.27	0.37	0.31	0.50

Figure D1: A 24x12 average profile for wind generation (MWh generated per MW installed) in Germany



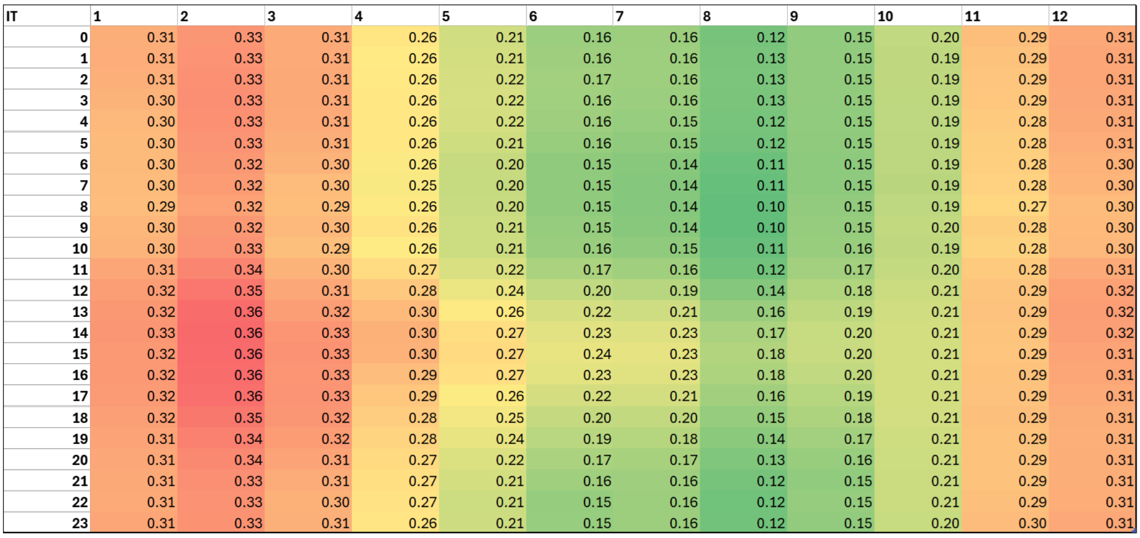
ES	1	2	3	4	5	6	7	8	9	10	11	12
0	0.35	0.38	0.34	0.32	0.27	0.25	0.23	0.21	0.23	0.25	0.34	0.33
1	0.35	0.37	0.33	0.31	0.26	0.24	0.22	0.21	0.22	0.24	0.33	0.33
2	0.35	0.37	0.33	0.30	0.26	0.23	0.21	0.20	0.21	0.24	0.33	0.32
3	0.35	0.37	0.33	0.30	0.25	0.22	0.20	0.19	0.21	0.24	0.33	0.32
4	0.35	0.37	0.32	0.30	0.25	0.22	0.20	0.19	0.21	0.24	0.33	0.32
5	0.35	0.37	0.32	0.29	0.25	0.22	0.19	0.19	0.20	0.23	0.33	0.32
6	0.34	0.37	0.31	0.29	0.24	0.21	0.18	0.18	0.20	0.23	0.34	0.31
7	0.34	0.36	0.31	0.28	0.24	0.21	0.18	0.18	0.20	0.23	0.34	0.31
8	0.34	0.36	0.30	0.29	0.25	0.21	0.17	0.17	0.20	0.23	0.34	0.30
9	0.33	0.35	0.31	0.30	0.25	0.22	0.18	0.18	0.20	0.23	0.34	0.29
10	0.32	0.35	0.31	0.29	0.24	0.21	0.16	0.17	0.20	0.22	0.34	0.28
11	0.33	0.37	0.32	0.30	0.25	0.22	0.18	0.18	0.20	0.23	0.35	0.29
12	0.35	0.39	0.33	0.32	0.26	0.24	0.19	0.19	0.21	0.24	0.36	0.30
13	0.36	0.40	0.34	0.34	0.28	0.25	0.21	0.21	0.22	0.25	0.37	0.31
14	0.37	0.41	0.35	0.35	0.30	0.27	0.23	0.23	0.24	0.26	0.37	0.32
15	0.37	0.41	0.36	0.37	0.32	0.29	0.25	0.25	0.25	0.26	0.37	0.32
16	0.36	0.41	0.36	0.38	0.33	0.30	0.27	0.26	0.25	0.26	0.37	0.32
17	0.36	0.40	0.35	0.37	0.33	0.30	0.28	0.27	0.26	0.26	0.37	0.32
18	0.36	0.40	0.35	0.36	0.33	0.30	0.28	0.27	0.25	0.26	0.37	0.33
19	0.36	0.39	0.36	0.35	0.32	0.29	0.27	0.27	0.26	0.26	0.37	0.33
20	0.36	0.39	0.36	0.34	0.32	0.29	0.28	0.27	0.26	0.26	0.36	0.33
21	0.36	0.38	0.35	0.33	0.31	0.28	0.27	0.26	0.25	0.25	0.36	0.33
22	0.36	0.38	0.35	0.32	0.29	0.26	0.24	0.24	0.24	0.25	0.35	0.32
23	0.36	0.37	0.34	0.32	0.29	0.25	0.23	0.23	0.23	0.25	0.35	0.32

Figure D2: A 24x12 average profile for wind generation (MWh generated per MW installed) in Spain



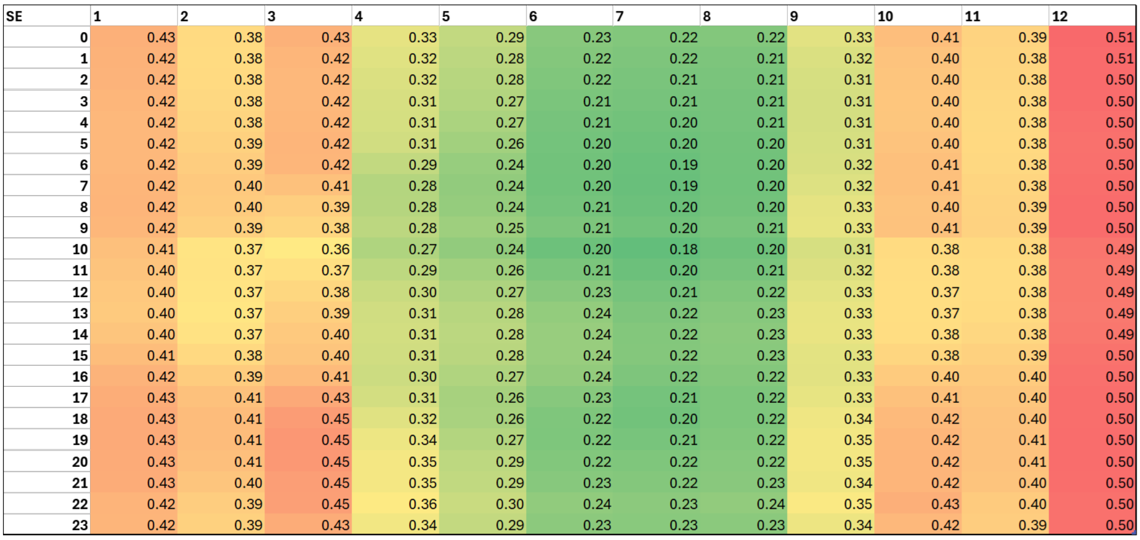
FI	1	2	3	4	5	6	7	8	9	10	11	12
0	0.35	0.36	0.45	0.35	0.31	0.24	0.21	0.20	0.32	0.36	0.40	0.48
1	0.35	0.36	0.44	0.35	0.30	0.23	0.21	0.19	0.31	0.36	0.40	0.48
2	0.35	0.36	0.44	0.34	0.30	0.22	0.20	0.19	0.30	0.36	0.40	0.48
3	0.35	0.35	0.44	0.34	0.29	0.21	0.19	0.18	0.30	0.36	0.40	0.48
4	0.35	0.35	0.44	0.33	0.27	0.20	0.18	0.18	0.30	0.36	0.40	0.48
5	0.35	0.35	0.44	0.31	0.26	0.19	0.17	0.17	0.30	0.36	0.40	0.48
6	0.35	0.35	0.43	0.30	0.25	0.19	0.17	0.17	0.31	0.37	0.40	0.48
7	0.35	0.35	0.41	0.29	0.26	0.20	0.18	0.17	0.31	0.36	0.40	0.48
8	0.35	0.34	0.39	0.29	0.27	0.20	0.19	0.18	0.31	0.36	0.40	0.48
9	0.35	0.33	0.39	0.30	0.29	0.21	0.20	0.18	0.32	0.36	0.40	0.48
10	0.35	0.32	0.36	0.28	0.27	0.21	0.19	0.17	0.30	0.35	0.39	0.48
11	0.34	0.31	0.37	0.30	0.29	0.22	0.20	0.18	0.31	0.35	0.39	0.47
12	0.34	0.31	0.38	0.31	0.30	0.22	0.21	0.19	0.31	0.35	0.40	0.47
13	0.34	0.32	0.40	0.31	0.30	0.23	0.21	0.19	0.31	0.35	0.40	0.47
14	0.34	0.33	0.41	0.31	0.30	0.22	0.21	0.19	0.31	0.36	0.41	0.48
15	0.35	0.35	0.43	0.31	0.29	0.22	0.20	0.18	0.31	0.38	0.42	0.48
16	0.35	0.36	0.46	0.31	0.28	0.21	0.19	0.18	0.32	0.39	0.42	0.48
17	0.35	0.36	0.47	0.33	0.28	0.20	0.19	0.18	0.33	0.39	0.43	0.48
18	0.35	0.37	0.48	0.35	0.29	0.20	0.19	0.19	0.34	0.39	0.43	0.48
19	0.35	0.36	0.47	0.36	0.31	0.21	0.20	0.20	0.34	0.39	0.43	0.48
20	0.35	0.36	0.46	0.36	0.32	0.22	0.21	0.21	0.34	0.38	0.43	0.48
21	0.35	0.36	0.46	0.36	0.32	0.23	0.22	0.21	0.33	0.37	0.42	0.48
22	0.36	0.36	0.47	0.38	0.33	0.24	0.22	0.22	0.35	0.38	0.42	0.48
23	0.36	0.36	0.45	0.36	0.32	0.24	0.22	0.21	0.33	0.37	0.42	0.48

Figure D3: A 24x12 average profile for wind generation (MWh generated per MW installed) in Finland



IT	1	2	3	4	5	6	7	8	9	10	11	12
0	0.31	0.33	0.31	0.26	0.21	0.16	0.16	0.12	0.15	0.20	0.29	0.31
1	0.31	0.33	0.31	0.26	0.21	0.16	0.16	0.13	0.15	0.19	0.29	0.31
2	0.31	0.33	0.31	0.26	0.22	0.17	0.16	0.13	0.15	0.19	0.29	0.31
3	0.30	0.33	0.31	0.26	0.22	0.16	0.16	0.13	0.15	0.19	0.29	0.31
4	0.30	0.33	0.31	0.26	0.22	0.16	0.15	0.12	0.15	0.19	0.28	0.31
5	0.30	0.33	0.31	0.26	0.21	0.16	0.15	0.12	0.15	0.19	0.28	0.31
6	0.30	0.32	0.30	0.26	0.20	0.15	0.14	0.11	0.15	0.19	0.28	0.30
7	0.30	0.32	0.30	0.25	0.20	0.15	0.14	0.11	0.15	0.19	0.28	0.30
8	0.29	0.32	0.29	0.26	0.20	0.15	0.14	0.10	0.15	0.19	0.27	0.30
9	0.30	0.32	0.30	0.26	0.21	0.15	0.14	0.10	0.15	0.20	0.28	0.30
10	0.30	0.33	0.29	0.26	0.21	0.16	0.15	0.11	0.16	0.19	0.28	0.30
11	0.31	0.34	0.30	0.27	0.22	0.17	0.16	0.12	0.17	0.20	0.28	0.31
12	0.32	0.35	0.31	0.28	0.24	0.20	0.19	0.14	0.18	0.21	0.29	0.32
13	0.32	0.36	0.32	0.30	0.26	0.22	0.21	0.16	0.19	0.21	0.29	0.32
14	0.33	0.36	0.33	0.30	0.27	0.23	0.23	0.17	0.20	0.21	0.29	0.32
15	0.32	0.36	0.33	0.30	0.27	0.24	0.23	0.18	0.20	0.21	0.29	0.31
16	0.32	0.36	0.33	0.29	0.27	0.23	0.23	0.18	0.20	0.21	0.29	0.31
17	0.32	0.36	0.33	0.29	0.26	0.22	0.21	0.16	0.19	0.21	0.29	0.31
18	0.32	0.35	0.32	0.28	0.25	0.20	0.20	0.15	0.18	0.21	0.29	0.31
19	0.31	0.34	0.32	0.28	0.24	0.19	0.18	0.14	0.17	0.21	0.29	0.31
20	0.31	0.34	0.31	0.27	0.22	0.17	0.17	0.13	0.16	0.21	0.29	0.31
21	0.31	0.33	0.31	0.27	0.21	0.16	0.16	0.12	0.15	0.21	0.29	0.31
22	0.31	0.33	0.30	0.27	0.21	0.15	0.16	0.12	0.15	0.21	0.29	0.31
23	0.31	0.33	0.31	0.26	0.21	0.15	0.16	0.12	0.15	0.20	0.30	0.31

Figure D4: A 24x12 average profile for wind generation (MWh generated per MW installed) in Italy



SE	1	2	3	4	5	6	7	8	9	10	11	12
0	0.43	0.38	0.43	0.33	0.29	0.23	0.22	0.22	0.33	0.41	0.39	0.51
1	0.42	0.38	0.42	0.32	0.28	0.22	0.22	0.21	0.32	0.40	0.38	0.51
2	0.42	0.38	0.42	0.32	0.28	0.22	0.21	0.21	0.31	0.40	0.38	0.50
3	0.42	0.38	0.42	0.31	0.27	0.21	0.21	0.21	0.31	0.40	0.38	0.50
4	0.42	0.38	0.42	0.31	0.27	0.21	0.20	0.21	0.31	0.40	0.38	0.50
5	0.42	0.39	0.42	0.31	0.26	0.20	0.20	0.20	0.31	0.40	0.38	0.50
6	0.42	0.39	0.42	0.29	0.24	0.20	0.19	0.20	0.32	0.41	0.38	0.50
7	0.42	0.40	0.41	0.28	0.24	0.20	0.19	0.20	0.32	0.41	0.38	0.50
8	0.42	0.40	0.39	0.28	0.24	0.21	0.20	0.20	0.33	0.40	0.39	0.50
9	0.42	0.39	0.38	0.28	0.25	0.21	0.20	0.21	0.33	0.41	0.39	0.50
10	0.41	0.37	0.36	0.27	0.24	0.20	0.18	0.20	0.31	0.38	0.38	0.49
11	0.40	0.37	0.37	0.29	0.26	0.21	0.20	0.21	0.32	0.38	0.38	0.49
12	0.40	0.37	0.38	0.30	0.27	0.23	0.21	0.22	0.33	0.37	0.38	0.49
13	0.40	0.37	0.39	0.31	0.28	0.24	0.22	0.23	0.33	0.37	0.38	0.49
14	0.40	0.37	0.40	0.31	0.28	0.24	0.22	0.23	0.33	0.38	0.38	0.49
15	0.41	0.38	0.40	0.31	0.28	0.24	0.22	0.23	0.33	0.38	0.39	0.50
16	0.42	0.39	0.41	0.30	0.27	0.24	0.22	0.22	0.33	0.40	0.40	0.50
17	0.43	0.41	0.43	0.31	0.26	0.23	0.21	0.22	0.33	0.41	0.40	0.50
18	0.43	0.41	0.45	0.32	0.26	0.22	0.20	0.22	0.34	0.42	0.40	0.50
19	0.43	0.41	0.45	0.34	0.27	0.22	0.21	0.22	0.35	0.42	0.41	0.50
20	0.43	0.41	0.45	0.35	0.29	0.22	0.22	0.22	0.35	0.42	0.41	0.50
21	0.43	0.40	0.45	0.35	0.29	0.23	0.22	0.23	0.34	0.42	0.40	0.50
22	0.42	0.39	0.45	0.36	0.30	0.24	0.23	0.24	0.35	0.43	0.40	0.50
23	0.42	0.39	0.43	0.34	0.29	0.23	0.23	0.23	0.34	0.42	0.39	0.50

Figure D5: A 24x12 average profile for wind generation (MWh generated per MW installed) in Sweden