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Operational Scenarios in the Crete-Aegean Hydrogen Valley: Impacts of Hydrogen Demand and Infrastructure Design

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Abstract

In the realm of decarbonization and clean technologies, whose future development will affect the evolution of the energy systems known today, green hydrogen is becoming a major contributor. It can be produced through the electrolysis process from water, exploiting green electricity from renewable energy sources to avoid GHG emissions. The aim of this study is to analyze the development of the Crete-Aegean Hydrogen Valley, known as the CRAVE-H2 project, where most aspects of the supply chain of green hydrogen are addressed. Located on the island of Crete, its strategic position allows the exploitation of electric and gas network connections between the European and African continents, as well as the favourable Mediterranean weather supplying high RES electricity production. With an electrolysis capacity of 4MW, the Crete-Aegean Hydrogen Valley is expected to produce 500 tons of green hydrogen per year, which will progressively increase to contribute to the supply of the transport and maritime sector as well as European industries. As multiple components are involved in the plant, it is fundamental to understand their functioning and interactions in a real setting. To achieve this goal, a model of the valley has been created exploiting PyPSA - Python for Power System Analysis, which allows a more intuitive representation of all components. The model facilitates the optimization of the valley operation, through an annual simulation with hourly timesteps which aims at minimizing the total costs of the plant. The system is analysed in increasing hydrogen demand scenarios, assuming a progressive integration of hydrogen in the energy system surrounding the hydrogen valley. The results show a strong

dependency of the electrolyser operation on the RES availability, which causes a low electrolyser load factor and indicates the importance of a precise sizing of the components. Moreover, despite the requirements for green hydrogen production, grid support results to be fundamental to avoid RES plant oversizing, suggesting the need for a BESS system to further optimize RES production. Downstream hydrogen storage turns out to be fundamental for reliable load supply, stabilizing hydrogen production through an optimized operational strategy. The model proves valuable as a decision support tool, helping planners optimize both design choices and operations throughout the valley. Its adaptable nature makes it possible to evaluate different scenarios and examine key components in detail, allowing future adjustments to meet the specific needs of different case studies.

Nomenclature

GHG	Greenhouse Gas
PV	Photovoltaic
$BESS$	Battery Energy Storage System
ETS	Emission Trading System
$RFNBO$	Renewable Fuels of Non Biological Origin
WGS	Water Gas Shift
SMR	Steam Methane Reforming
RES	Renewable Energy Source
AEL	Alkaline electrolyser
$SOEC$	Solid Oxide electrolyser
$PEMEL$	Proton Exchange Membrane electrolyser
EHB	European Hydrogen Backbone
HtA	Hard to Abate
FCV	Fuel Cell Vehicles
ICE	Internal Combustion Engine
TSO	Transmission System Operator
HRS	Hydrogen Refueling Station
LH_2	Liquid Hydrogen
CH_2	Compressed Hydrogen
$LCHO$	Liquid Organic Hydrogen Carrier
$SOFC$	Solif Oxide Fuel Cell
$RWGS$	Reverse Water Gas Shift
TRL	Technology Readiness Level
FC	Fuel Cell
$LCOH$	Levelized Cost Of Hydrogen
$CapEx$	Capital Expenditures
$OpEx$	Operational Expenditures
MPC	Model Predictive Control
$FCEV$	Fuel Cell Electric Vehicles
LP	Low Pressure
MP	Medium Pressure
HP	High Pressure
$PEMFC$	Proton Exchange Membrane Fuel Cell
ORC	Organic Rankine cycle
HX	Heat Exchanger

LNH_3	Liquid Ammonia
$ENTSO-E$	European Network of Transmission System Operators - Electricity
SAI	Southern Aegean Interconnector
$IPTO$	Independent Power Transmission Operator
GAP	Greece Africa Power Interconnection
AWE	Alkaline Water Electrolysis

Chapter 1

Introduction on Hydrogen

1.1 Context

Hydrogen is found in nature as an odorless, colorless and highly flammable gas, whose molecular form is made of two hydrogen atoms. Each of them presents one electron and one proton. It is the lightest atom, as well as the most abundant on planet Earth, as it is present in the water molecules, in the atmosphere (in very small amounts) and in many organic and inorganic compounds. Some relevant properties of hydrogen are summarized in the table below. Hydrogen is becoming increasingly interesting as it has proven to be an alternative to natural gas, as well as an energy vector with exceptional characteristics. As research progresses, it is more and more evident how clean technologies will play an always bigger role against climate change. Changes in average weather patterns have been observed since the mid-20th century and are strictly related to human activities, especially fossil fuel consumption. As fossil fuels are burned, a large variety of greenhouse gases (GHG) are released into the atmosphere and their name suggests, they contribute to strengthening the greenhouse effect around our planet. GHG behave as a barrier and consequently, heat generated on Earth's surface becomes trapped in the lower atmosphere, rising Earth's average surface temperature. Global warming refers to the heating of the Earth's surface that has been observed in the past decades in comparison to the pre-industrial period (1850-1900). Specifically, the increase in the global average temperature caused by human activities is estimated to be about 1 degree Celsius, a number increasing every decade by 0.2 degrees Celsius. Climate change is nowadays evidenced in many ways, not only in temperature, but also in the rising levels of the oceans, the more frequent extreme weather events such as hurricanes or floods, as well as changes in the annual vegetation cycles. [7]

In the EU, in 2022, about 50% of the emissions responsible for the greenhouse effect were constituted by CO_2 (40.3%), CH_4 (6%), N_2O (2.6%) and fluorinated gases (1%) and the major contributors in terms of sectors were the energy supply, the domestic transport and the industry sectors. In this context, it is relevant to mention the positive contribution of the land and forestry sector, which helps reduce CO_2 concentration in the atmosphere by photosynthesis. For this reason, forests are often referred to as "carbon sinks", storing large amounts of CO_2.[8]

For what concerns the current trends, the COVID-19 pandemic generated a reduction in GHG emissions, but a rebound was registered in 2021, especially from fuel combustion. As the map below clearly states, some countries are more emitting than others, in particular China and the US alone were responsible for 45% of global fuel combustion emissions. [9]

All over the world research about climate change is constantly being conducted, allowing the availability of large amounts of information and data regarding a sensible topic as climate change, but the discussion has been ongoing since the 1970s when the term "sustainability" was first used with the meaning it still holds today. Since then, some cornerstone events have marked history, such as the adoption of the Kyoto Protocol in 1997 in which signing countries committed to limit and reduce greenhouse gas emissions. [10]. It was only in 2016, with the signing of the Paris Agreements, that major world economies set specific targets to limit global warming. More specifically, it sets the target of keeping the global temperature rise below 2 degrees Celsius with respect to pre-industrial levels, but also to pursue efforts to decrease this number to 1.5 degrees Celsius. Among other commitments, all signing countries must prepare and communicate measures to achieve their national goals. Despite the efforts put over these past few decades into discussing climate change and possible solutions to it, emissions keep increasing and planet Earth keeps suffering from it. [11]. The most recent UN Climate Change Conference, COP28, was held in Dubai and was classified as the biggest so far. More than 150 Heads of State and Government reunited in the United Arab Emirates, a region particularly vulnerable to the impacts of the climate crisis.[12]. Among key findings and results of the conference, it was communicated that current climate pledges have not set the world on track to limit global warming below 1.5 degrees Celsius. [13] It is now more important than ever to dedicate time and resources to developing clean technologies and green hydrogen is one of them. Hydrogen is an energy carrier that finds many applications and advantages in the energy sector, where is most known for its use in fuel cells to produce electricity without polluting, as the only by-product of a fuel cell is water. A large advantage of hydrogen resides in its high specific energy density, as it can provide about three times more energy than gasoline combustion per unit mass. On the contrary, it has very low energy for its volume, which means advanced storage technologies are required. Some of its characteristics are similar to those of natural gas, therefore many applications under study nowadays are aiming at gradually decarbonizing high emissions sectors by introducing a blend of hydrogen and natural gas, thereby reducing the latter's consumption. [14]

1.2 Classification

In 2022, hydrogen demand in Europe was 8.2Mt, of which more than 50% was dedicated to refineries, where hydrogen is produced by steam reforming of natural gas or as a by-product of other processes and then consumed for hydrocracking, where main contaminants are removed from crude oil, and hydrotreating processes, where the long hydrocarbon chains are broken into lighter ones. Another large percentage of current hydrogen demand is dedicated to ammonia production, where H_2 is again produced by steam reforming and then exploited in the Haber-Bosch process to produce NH_3. Less developed but still relevant is the production of methanol where H_2 is fed to a reactor together with CO or CO_2. As mentioned, these processes employ natural gas to produce hydrogen required as feedstock, which means that a certain amount of pollution is related to the consumption of natural gas. To specify the provenience of hydrogen and therefore the source of its production, a code has been created and the main components are brown H_2 from coal with CO_2 emissions during the process. Grey H_2 comes from natural gas, for example via steam methane reforming and therefore processes responsible for CO_2 emissions and not suitable for a route towards net zero; Blue H_2 refers to similar processes to that of grey H_2, with the difference of having implemented CO_2 capture and storage technologies. As for Grey H_2, also Blue H_2 is at risk of methane leakage, which implies a negative impact on the GHG emissions.[15] Green H_2, where no CO_2 emissions occur during the process. In the realm of reducing CO_2 emissions in the atmosphere, green H_2 is clearly the most ambitious solution, although some challenges involve the still high costs of production and storage. An important advantage of Green H_2 resides in the source of energy for its production, which is renewable energy. When referring to RES, they are usually defined as unprogrammable, meaning that electricity production cannot be controlled as it depends on various factors related to the weather conditions which can be predicted with some uncertainty, but cannot be controlled. PV production for example is limited to the central hours of the day, when the irradiance is at an acceptable level and also when the energy demand is normally lower. Therefore, as more and more RES plants will be commissioned, more and more electricity will be produced when it is not ready to be consumed. A large portion will be destined to charge electricity storage systems (BESS), but some of it would necessarily be curtailed. This is where hydrogen becomes an interesting solution, as it can be produced from electricity that would otherwise be wasted. The coupling of RES and hydrogen enables the latter to fully exploit its potential as an energy carrier, becoming a source of storage of electricity. [6]

1.3 EU Policy Review

To ensure the rapid development of clean technologies, including green hydrogen, the most relevant tool is policy. Emission reduction targets are the main drivers of this process, but it is fundamental to push the technological development required to achieve said targets. At the EU level, the long-term vision was set with the Fit for 55 package, setting the goal of reducing 55% of emissions by 2030 and total climate neutrality by 2050. The package is intended to stimulate the energy transition while still maintaining the competitiveness of the EU industry sector, by reforming the Emission Trading System (ETS), which is a mechanism of exchange of emission quotas. A carbon market was instituted, and the revenues are dedicated to further investments against climate change. Concerning hydrogen, further policies at the EU level were defined, starting from the Renewable Energy Directive (RED), which, among many other obligations, sets a target for the consumption of hydrogen in specific sectors, such as industry and transport. RED was initially developed in 2010, but with the publication of the Fit for 55 package, it was revised and stated that by 2030 renewable energy was expected to cover a percentage of the industry sector demand increasing by 1.6% each year. Regarding hydrogen, the target was set at 2030, to have 42% RFNBO hydrogen of the total demand in industry. For further specifications in the heavy transport sectors, ReFuel EU Aviation & Maritime are directives imposing a certain percentage of RFNBO (Renewable Fuels of Non-Biological Origin), including hydrogen, in their fuel demand. Policy is a necessary and powerful tool to bring structural changes to Europe's energy, industry and transport sector, but it becomes truly effective only with the economic support of incentives for technological development. Many clean technologies are still hindered by extremely high costs, which is the reason why many investment funds have been created in the past few years. One example at the EU level is the Hydrogen Bank, which launched the first auction to fund hydrogen production at the end of 2023. [16]

1.4 Production Pathways

Although hydrogen is the most abundant element on Planet Earth, it cannot be found naturally in large quantities and must therefore be produced. Some of the methods employed have already been mentioned and further specification will follow. Steam methane reforming is one of the most common processes, involving the use of methane and water as reactants to obtain hydrogen and carbon monoxide. The main component is a reactor to which methane is fed together with steam and where the main reaction occurs. The reformate is a mixture of hydrogen, carbon monoxide, reagents residue and some other substances. In order to fully exploit the potential hydrogen production, the following step is the water gas shift (WGS) reaction, which combines carbon monoxide and water leading to hydrogen and carbon dioxide production. A cleaning step is required to ensure pure hydrogen can be collected. SMR advantages reside in the low cost and the high efficiency but cannot be considered a clean solution as not only CO_2 is one of the byproducts, but also methane leakage is a risk. A similar process can be achieved starting from coal which can be gasified into syngas and fed to a similar reactor and followed by the WSG again. The efficiency of this process is quite low, around 30% and higher in GHG emissions. Biomass can be another source of hydrogen production, either starting with crops that undergo gasification to obtain syngas, or with biogas containing methane which is separated and fed to the SMR reactor. Introducing cleaner options, electrolysis is a process that requires electricity as a source, therefore the amount of GHG emissions associated with this process strictly depends on the source of electricity. In the case of green hydrogen, RES technologies must be involved to supply electricity to the electrolyser. It is a device in which electricity is exploited to split the water molecule into hydrogen and oxygen molecules. A variety of technologies have been developed, sharing the common traits of the electrolyser employed and varying in materials and operational conditions. An electrolyser is an open electrochemical cell that drives a non-spontaneous reaction, therefore the reagents can be fed continuously (open mass exchange) and the reaction occurring requires external input, electricity, to activate. Overall, the aim is to convert electrical energy into chemical energy, through a RedOx reaction which is split between the two sides of the device: the anode, where the oxidation reaction occurs and the cathode, where the reduction reaction occurs. An external circuit supplies the electricity required for the reactions to be activated. Three main types of electrolysers for hydrogen production are the alkaline electrolyser (AEL), the solid oxide electrolyser (SOEC) and the proton exchange membrane electrolyser (PEMEL). They are known according to the type of material exploited in the central section of the device, separating the anode and cathode, which is the electrolyte. In the case of the AEL, a liquid solution of water and KOH is employed, allowing for the transfer of OH- anions from cathode to anode. It works at quite low temperatures, around 70-80° Celsius. The PEMEL electrolyte is Nafion, a solid polymeric material created starting from Teflon and modifying its molecule thereby adding a hydrogen atom with high mobility. PEMEL presents similar working conditions to AEL, especially in terms of temperature which is again around 70-80° Celsius. The advantage of low-temperature electrolysers resides in their flexibility to work both as baseload, continuously in time, and with more or less frequent ramps. This is not possible in the case of a SOEC, which works at 700-750° Celsius and requires time and resources to reach nominal operating conditions. The electrolyte is Yttria-stabilized-Zirconia, a ceramic material able to allow the transfer of the O2- anion from cathode to anode. The advantage of the SOEC is the higher efficiency of the process compared to low-temperature alternatives. More recent technological innovation has taken place in this field, introducing other methods for renewable hydrogen production, namely chemical looping processes and the photoelectrochemical cell. The former consists in the direct use of solar irradiance to induce loops of chemical reactions which allow the production of different chemical species, especially hydrogen and carbon monoxide. The photoelectrochemical cell, on the other hand, is a device combining a photovoltaic and an electrochemical cell, that is, able to exploit photons energy to activate the RedOx reactions occurring in an electrolyser as previously described. Some limitations are related to the requirements of the material employed for the electrodes, as it should be a semiconductor with intermediate levels of band gap, high enough to generate a useful effect and low enough to receive the energy of a photon.

1.5 Transportation and Distribution Methods

Production is one of the main steps of the supply chain of hydrogen, together with distribution, storage and final use which are the most relevant to this study. Currently, the green hydrogen supply chain is under development and still lacking in some sectors, but at the EU level there are large investments planned to allow the hydrogen economy to take place, especially in terms of distribution. Hydrogen distribution, or more generally transport, is not trivial and implies not only high costs but also technical complexity. For this reason, most of the hydrogen used worldwide is consumed in proximity to where it is produced. Whenever this is not a viable solution, a system that allows hydrogen transport from its production to its consumer location is required and there are three main methods to complete this task. As for natural gas distribution, also hydrogen can be distributed via pipelines, at a relatively low cost, over long distances.[17] Currently, being the necessary infrastructure still under development, most countries have regulations concerning the possibility of blending hydrogen in the natural gas existing pipelines. A strict limit of blending percentage is imposed for safety reasons, due to the peculiar characteristics of hydrogen which makes it necessary to have a dedicated infrastructure. In particular, pipe material must be carefully considered to avoid hydrogen embrittlement. [18] The European Hydrogen Backbone (EHB) is the most relevant initiative at the EU level to enable hydrogen infrastructure development and to which 33 energy infrastructure operators covering 28 European countries are taking part. The 2030 hydrogen infrastructure map would consist of a total length of about 28000km, repurposing existing natural gas and building new hydrogen pipelines. Five main corridors are listed below:

- Southern Europe corridor: connecting Tunisia and Algeria to central Europe, passing through Italy, allowing import of renewable hydrogen from North Africa to decarbonise large industries along its path.

- South-west corridor: allowing the Iberian Peninsula to export its large and low-cost hydrogen production and eventually connecting to Morocco

- North Sea corridor: exploiting the high offshore wind capacity developing in northern countries, hydrogen production in this region could reach the Netherlands and supply all large industrial clusters of this region

- Eastern European corridor: larger renewable energy capacity in Romania, Greece and Ukraine could be exploited, although the future natural gas flows and geopolitics of this region could impact the development of this corridor

- Nordic & Baltic corridor: similar to the North Sea corridor, also in these regions a large hydrogen infrastructure could be based on the high onshore and offshore wind potential. [19]

Pipeline hydrogen distribution is currently the most promising method, however it cannot be a standalone system, as some regions where large hydrogen production can be achieved following the large RES potential, may not be easy to reach via pipeline. Alternatively, high-pressure tube trailers allow compressed hydrogen transport by trucks, ships or railcars, although it is an expensive solution and unsustainable for very long distances. Gaseous hydrogen is compressed to about 180bar into long cylinders that are then mounted on the transport of choice. Finally, hydrogen can be transported and distributed in liquid form, via liquified hydrogen tankers. This is again an expensive solution, as cryogenic liquefaction is a complex process requiring temperature to be lowered to about 21K in order for it to become liquid, presenting the risk of boil-off at the moment of consumption. Nevertheless, it's an efficient practice allowing for long-distance transport by trucks, railcars or ships.

1.6 Demand

For what concerns hydrogen demand, the Clean Hydrogen Monitor indicates that in 2022 the total European demand was 8.2Mt, most of which, 81%, is attributed to industrial sectors of ammonia production and refineries. Lower demand is related to other subsectors of the chemical industry, namely methanol and other chemical production. Finally, hydrogen for industrial heat is a low, but growing demand. Most of the above-mentioned sectors, especially the chemical industry, require hydrogen as feedstock, although a large potential could eventually be attributed to high-emission industrial sectors, known as the Hard-to-Abate (HtA) sectors, where future technological innovation and electrification would contribute to an increasing hydrogen demand. The HtA industries, as the name suggests, are those responsible for large fossil fuel consumption, and consequently, large GHG emissions, for which a clean alternative is yet to be found or economically sustainable. Some examples are steel, non-metallic materials (paper, ceramic, glass, cement) manufacturing, food and textiles industries. The production processes involved currently make up a large portion of natural gas consumption, as thermal energy is required for furnaces and cogenerators. Another interesting application of hydrogen is in the transport sector, for what concerns heavy transport as feed for a fuel cell which converts its chemical energy into electrical energy. As for electrolysers, also fuel cells can vary based on the materials used for the electrodes and electrolyte, but the working principle remains the same. Fuel cell vehicles (FCV) are then equipped with a battery and an electric motor. Concerning existing vehicles, presenting internal combustion engines (ICE), as well as turbines for aviation, a cleaner possibility is offered by synthetic fuels made from hydrogen, which could be introduced by adapting technologies that are already in use with retrofit measures. The transport sector represents a delicate matter since it represents the second most polluting sector in the European context, and technological solutions must be matched by regulations and directives imposing a gradual decarbonization for this sector. Among other applications for hydrogen, a relevant one is the possibility of grid balancing service through a fuel cell. As mentioned above, a fuel cell can convert hydrogen chemical energy into electrical energy, which could be of use to support grid balancing. Transmission System Operators (TSO) have the task of guaranteeing an adequate service to users connected to the grid, which implies maintaining constant frequency across the grid. Whenever demand does not match the electricity being injected into the grid, an imbalance is generated and grid balancing services are required. In the case of a sudden increase in demand, if the frequency is below a certain threshold, balancing can be offered by a hydrogen-fed fuel cell connected to the grid and injecting electricity to recover the original frequency level. Balancing services are fundamental for every user connected to the grid as they ensure stability and continuity of supply. Hydrogen availability in this context is a notable resource, especially since the increasing the number of renewable energy plants injecting electricity into the grid not only are not able to offer grid balancing services but rather worsen the situation as their production profile is uncontrollable.

1.7 Storage Systems

Among the various steps of the hydrogen supply chain, storage is necessary to fully exploit hydrogen potential as an energy carrier. It allows production and consumption both in terms of space and time to decouple, such that in a fully developed hydrogen economy the demand can be located far from the production site, but still be in reach through various transport methods. Moreover, the hourly production profile can follow the availability of RES energy without compromising the need for hydrogen at different moments of the day. At a macroscopic level, hydrogen storage can be divided into two categories, the first exploiting the physical state of hydrogen and the second taking advantage of the chemical properties of hydrogen, namely using it to create different molecules with different properties. The physical storage of hydrogen requires one of its physical properties to change based on necessity: it can be compressed by increasing its pressure or it can be liquified, by decreasing its temperature. Compressed gaseous hydrogen storage is the most common practice in this field, due to its simplicity and lower cost compared to other solutions. A specific vessel is required for this task and there are mainly four types:

- I type: it is fully made of metallic material and the maximum pressure it can withstand is around 30MPa. The gravimetric density is 1.7%wt, it is the cheapest option available, but the only available application is as a stationary storage for the industrial sector

- II type: it is made of metallic material, with the addition of glass fiber composite hoops around it. With a gravimetric density of 2.1%wt, it can withstand higher pressures, up to 90Mpa. Again, it can be used as stationary storage, but also as storage in a hydrogen refueling station (HRS)

- III type: it is made of composite material, with a metallic liner as well. Although the gravimetric density is 4.7%wt, it can withstand up to 70MPa of pressure. It is a notable option in the case of tube trailers or onboard H_2 storage

- IV type: it is a fully composite vessel, usually made of high-density polyethylene with glass or carbon fiber, able to support up to 70MPa and presents a gravimetric density of 5.7%wt. Most of the abovementioned applications are available for this type of vessel.

An interesting alternative to pressure vessels is underground hydrogen storage, which implies making use of existing underground volumes such as salt caverns, aquifers, or depleted gas reservoirs, where large volumes are available thus offering the possibility of seasonal storage. Temperature is the other physical property of hydrogen to be altered, as a low-temperature substance will present higher gravimetric and volumetric density. It is a complex technique, requiring high energy availability, due to some obstacles to overcome, namely the evaporation temperature, which is 20.28K (at 1 atm). The vessel choice is not easier: liquid hydrogen LH_2 is in danger of boil-off as it could evaporate by absorbing heat, which means the vessel must be able to withstand any type of heat leakage and be as thermally insulated as possible. Current technology can reach values of 1 to 5% of boil-off per day, but recent innovation in this field could lower this value to 0.04%. A combination of the two methods presented above is the cryo-compressed hydrogen storage CcH_2, guaranteeing higher density than LH_2 at relatively higher temperatures. It can be achieved by a sequence of compression stages with intercooling, followed by a refrigeration step. The vessel employed usually combines the characteristics of LH_2 and CH_2 storage tanks, for example, a type III vessel for CH_2, with additional insulation used for LH_2. Moreover, a vacuum enclosure is necessary, increasing the cost of the tank and making it suitable only for storing lower volumes. [20]

The second category of H_2 storage, as already mentioned, exploits the chemical properties of hydrogen when combined with other elements, therefore creating different materials and substances, which are defined as Liquid-Organic Hydrogen carriers LOHC. Hydrogen is added to molecules that present unsaturated bonds, through a chemical reaction. The reaction must be reversible and exothermic, such that, when needed, with the appropriate combination of temperature and pressure, hydrogen can be released through an endothermic reaction of dehydrogenation. An example of LOHC is homocyclic methylcyclohexane (MCH)/toluene, one of the first materials to be studied for this purpose. With toluene, the gravimetric density reaches 6.2%wt. LOHCs are not the only option for material-based hydrogen storage, as whatever material that can combine with hydrogen resulting in a stable compound could serve this purpose. Nevertheless, said material must also be able to release hydrogen at appropriate temperature and pressure when needed. Metal hydrides fit the description, being solid materials offering high gravimetric densities. Some examples are Li, Be, B, Na, Mg and Al. Among the properties they have in common, some relevant ones are fast kinetics, cycle stability, safety, low heat of formation and low heat dissipation during exothermic hydride formation. Finally, hydrogen material-based storage can be achieved with power fuels, substances in gas or liquid form that contain hydrogen and therefore can store it in their molecules but can also be used as fuels. They are called power fuels because electricity is needed to produce them through a chemical synthesis process. Only two are worthy of mention in this context, ammonia and methanol, as most of the others are not economically viable as storage means for hydrogen. Ammonia NH_3 is produced through the Haber-Bosch process, where a metallic catalyst is used and gaseous nitrogen N2 is combined with H_2. The advantage of dealing with ammonia is that the liquefaction process is much easier, requiring a temperature of –33°Celsius at 1atm. When needed, hydrogen is released with the reverse reaction at 200°Celsius, although at this temperature the procedure is very slow, therefore it is mostly done at 650°C with a catalyst. Ammonia can also be fed to a SOFC, obtaining an even higher efficiency process to recover stored energy. Methanol CH3OH, on the other hand, is produced from carbon monoxide CO_2 and hydrogen through one of three possible paths:

- Reverse water gas shift and methanol synthesis: the first step RWGS produces CO and water from hydrogen and CO_2, then CO is combined with H_2 to form methanol

- Direct synthesis: H_2 and CO_2 are combined to form methanol in a single-step procedure, with lower efficiency

- CoE and methanol synthesis: higher efficiency process involving the coelectrolysis of water and CO_2 to obtain H_2 and CO, followed by the CH_2OH synthesis

1.8 Hydrogen Valleys

Now that hydrogen as an energy carrier has been fully explored, it is proper to approach the subject of this paper, which is hydrogen valleys. This expression refers to large-scale hydrogen projects, where multiple aspects of the supply chain are addressed, from electricity source for H_2 production, storage, transport and off-takers. In order to better understand the concept and properly classify hydrogen valleys, there are some characteristics common to all of them, as they are large-scale projects; they have a clearly defined geographic scope, meaning they could focus on a local or regional area; more than one step of the H_2 supply chain is encompassed in the hydrogen valley; they are meant to serve multiple end users, for example in the transport or industrial sectors. The concept has developed mainly around green hydrogen production in the last few years, with rising interest, especially in Europe, where most projects have been announced despite the difficulties of the hydrogen market. European funds have had a large impact on these aspects, as most Hydrogen Valley developers are able to pursue their plans through public funds.

A common classification for hydrogen valleys sees three archetypes, where the main differences lay in the employed feedstock, the technology and the end users:

- Archetype 1: the geographic scope is quite limited, aiming at local consumption of hydrogen at a rather low pace, for example in the transport sector, where demand is the collection of multiple small end users who must join forces to reduce costs. The shared and centralized use of infrastructure and technology allows the reduction of the local emissions while remaining an economically sustainable investment for all participants. The capacity lies between 5 and 20MW of electrolysis and as of 2023, 40% of hydrogen valley projects are of the archetype 1

- Archetype 2: as the scope of these projects moves from local to regional, the medium-scale hydrogen valley is able to supply demand for larger end users such as in the industry sector. The aim is to decarbonize HtA industries such as steel or chemical industries, either as a substitute for natural gas or for grey hydrogen that is required as feedstock. The electrolysis capacity must increase to 20 to 300MW and are more frequently private initiatives driven by the necessity of decarbonization of the end user production process. As of 2023, they represent 40% of the hydrogen valley projects

- Archetype 3: in 2023, 20% of hydrogen valley projects are large-scale production facilities, with 500+MW of electrolysis capacity. They are mostly export-oriented, developed to generate enough hydrogen to reach international trade markets, where regulatory obstacles arise. Some examples can be found in the Middle East and North America where the underlying feedstock is more abundant, such as renewable energy

In terms of technology deployment, some commonalities can be found in currently under-development projects. Upstream, the hydrogen production is mostly relying on PEM electrolysers, followed by alkaline ones, whereas the remainder is building steam methane reformers with carbon capture units. It implies that mostly green hydrogen projects are under development and their success largely depends on their access to efficient and high-load-factor renewable energy sources as feedstock. Moving to the midstream section, which refers to storage and transportation, sees quite reduced variety, as cylinder storage and trucking seems to be the most advantageous solution. Nevertheless, with the increase of archetype 3 valleys, where large amounts of hydrogen are produced to be exported, the option of shipping is starting to be explored. In terms of transport methods, pipeline is also a quite appreciated alternative. Downstream along the supply chain, the end users of the hydrogen valleys have also remained consistent over the years. About 80% of the Valleys aim at decarbonizing the transport sector, developing infrastructure able to supply trucks or buses, or, in general, heavy-duty road mobility, with some exceptions exploring the possibility of decarbonized shipping. The other sector involved is the industrial one, as well as energy end uses, referring to the conversion into electricity such as for grid balancing services, or to the injection into the gas grid. Hydrogen Valleys progress and growth are not to be taken for granted, as some serious hurdles can be found. First, technology maturity is critical, as large-scale electrolysers currently have insufficient operational proof; hydrogen transport technologies are mostly at low TRL, for example LOHC. In terms of project execution, delay in RES build-out is playing a major role, increasing uncertainty in costs and availability, especially in Europe. On the regulatory front, even higher uncertainty is given by the lack of standards and experience, which could hinder the availability of investments as the willingness to pay remains elusive. [21]

Chapter 2

Literature Review

To contextualize this study in the realm of hydrogen valleys, the available literature has been analyzed. Some papers tend to focus more on the upstream and midstream sections of the hydrogen supply chain, whereas others focus mostly on the downstream section, modeling end-users and defining their demand. Very few studies see the system as a whole, creating a gap in the available literature.

2.1 Hydrogen Valleys

Petrollese et al. [22] carry out a techno-economic analysis of a green hydrogen valley, where the energy feedstock is represented by RES plants, both photovoltaic and wind farms. The supply of hydrogen is destined for four end users, spacing across most common hydrogen applications. Hydrogen is converted back into electricity through a 400kW solid oxide fuel cell for grid balancing services, fed to a hydrogen refueling station HRS where it needs to be compressed to 50Mpa and then consumed by a 6 FC buses fleet, injected into the natural gas pipeline at 0 to 5%vol blending and consumed as feedstock for the methanation process. To model said hydrogen valley, mathematical models were developed in MATLAB and Aspen Plus environments. Water electrolysis was done through a PEMEL which was found to be the most appropriate one for following the unpredictable and unstable RES load profile, with a ramping speed of 100%/s. The produced hydrogen mass flow rate was determined as a function of the input electrical power. Although production increases at increasing the stack power, the efficiency decreases, requiring compromising between these two factors. Hydrogen was managed, in order of priority, to supply the SOFC, fill the storage, increase blending % in the pipeline and supply the methanation process. It is found that lower storage capacity causes overproduction from grid energy (whenever RES electricity is not available). Nevertheless, the highest electrolyser efficiency is found at lower tank volumes, due to the higher frequency of part-load operation with grid energy to supply unavoidable demand.

Šimunović et al.[23] conduct the analysis of a single end-user for a hydrogen valley, a hydrogen refueling station HRS, considering three values for capacity and four operational conditions, where the variable is the geographic distance between each stage of the supply chain, therefore introducing different transport method where needed. HRS load profile is determined starting from an average driving shift schedule for the FC buses, such that an hourly profile was stochastically generated, considering factors such as consumer behavior, needs and habits. Before reaching the HRS, hydrogen is compressed in stages with intercooling. Simulations were carried out with MATLAB, over a period of 10 years and with an hourly time step. It was found that the electrolyser capacity factor decreases at increasing HRS capacity, due to the increasing electrolyser rated capacity needed to supply the load. Furthermore, the electrolyser sizing is carried out by analyzing the worst-case scenario, where the maximum daily load and the minimum RES energy production are combined.

Barigozzi et al.[24] took a further step in the hydrogen valley study as a whole system, modeling the supply chain from renewable energy production to the supply of an industrial user. The software employed is TRANSYS, where each step is introduced: PV panels as a renewable energy source, PEM electrolyser, compression stages, storage tank and all required complementary tools. Simulations are carried out over a year period with 0.125h time steps such that an optimization process can manage each step of the hydrogen supply chain. To ensure stable production and compensate for RES intermittency, an ultracapacitor energy storage system is used as it can inject and absorb power. The electrolyser efficiency is considered a function of the load, such that at part load the electrolyser efficiency is lower than at full load. After the electrolysis, hydrogen passes through an intercooled, reciprocating compressor and is finally stored in a composite tank. The output shows that on a seasonal basis, storage is not very relevant in supplying the user demand, due to prevalent direct use of hydrogen as well as low grid electricity cost. The optimization strategy ensures the lowest levelized cost of hydrogen LCOH as well as minimized energy consumption. Through this model it is possible to define each design variable for the components and could be applied to an existing plant as well as to a new one. The results showed a direct correlation between the renewable fraction, such that a higher renewable fraction require higher electrolyser capacity. Storage follows the same trend, as larger tanks can absorb production peaks although requiring higher investments.

Specifically to the hydrogen valley topic, Sánchez et al.[25] developed an Aspen Plus model to analyze the system performance. For this study, an alkaline water electrolyser AEL is employed, being one the most mature technologies, made of Ni-based electrodes and a liquid electrolyte which is a solution of KOH in water. It works at low pressures, around 30 bar, and low temperatures, around 60 to 90°C. To model the electrolyser, the polarization curve must be included as well as the Faraday efficiency and some way of accounting for the temperature influence. Aspen Plus does not contain an already created model for an electrolyser, which has to be built specifically for the system, whereas all other components in the Balance of Plant can be chosen from the libraries. The electrolyser model is constituted by a stack where H_2 and O2 streams are produced and with the KOH electrolyte are led to two separators where the electrolyte and the gas are separated. The inputs required by the model are the number of cells, the electric power input, the active area of the electrode, temperature and pressure. The outputs are hydrogen and oxygen production, water consumption, heat generated and heat loss. The balance of plant BoP includes water supply, heat exchangers, separator vessels, circulation pumps and cooling loop. A parametric study is conducted increasing temperature from 50°C to 80°C as the voltage progressively reduces, as well as the power required. As pressure varies in the range of 5 to 9 bar, the voltage increases and there are no variations in the H_2 production.

The upstream section of the supply chain of green hydrogen is explored in the study conducted by Armijo et al.[26], who pose the question of how production is affected by the variability of solar and wind energy, especially in economic terms. The techno-economic analysis aims at modeling the production costs starting from renewable energy potential in Chile and Argentina, estimating the total installation potential in the two countries, as well as the market situation for both hydrogen and ammonia. The latter is found to be the most cost-efficient solution, allowing to avoid the high costs related to transportation and storage of hydrogen. For the model, hourly data is retrieved, accounting for the technical losses as well. The electrolyser is assumed to be alkaline, able to adapt to changes in electricity supply and presenting 70% efficiency. CapEx and OpEx costs are collected from external sources to compute the levelized cost of hydrogen LCOH. An optimization procedure is exploited to find the main parameters of the plants in all considered locations, obtaining values ranging from 2.12 USD/MWh to 35.8 USD/MWh, where high variability is related to different sources (wind and solar) and operating parameters. Concerning ammonia, higher complexity is required due to the more extensive production path, reaching a levelized cost of ammonia ranging from 462 USD/t to 571 USD/t. It is found that combining solar and wind technologies does not have a large effect on the hydrogen production costs, whereas a 5-20% impact is recorded on ammonia production costs, as it allows an increase in RES stabilization, thus reducing storage costs.

Analyzing a more complete hydrogen supply chain, Cardona et al.[27] aimed at modeling a system for local hydrogen production, where the user HRS is located close to the electrolyser thereby avoiding transportation necessities. The source is represented by solar energy, together with a grid connection for additional support, whereas the final consumers are light and heavy-duty vehicles as well as gas containers. The model focuses on the HRS, creating a Model Predictive Control MPC which solves multi-objective optimizations to understand optimal plant dynamics. A network of 21 electrolysers is followed by a multistage compression system and cascade storage HRS. The objectives set for the optimization are economic profit, regulation and control softening. In terms of economic profit, the three services offered correspond to three income streams, where hydrogen cost varies from 2€/kg to 10€/kg, whereas costs are given by the grid electricity costs. For the regulation, the model sets alert signals whenever the refueling fulfilments are not satisfied. Finally, control softening is applied to avoid fast actuator variations.

As mentioned before, hydrogen valleys can be scaled in size and geographic scope, as the context of their application can vary widely. One interesting example is explored by Hasan et al.[28] in the choice of exploiting hydrogen potential to supply isolated communities in Australia. Low land availability implies that hydrogen must be imported from the mainland and fed to a fuel cell to supply the islands with electricity. The daily hydrogen requirements are established assuming 70% fuel cell efficiency. The purpose of the paper is to identify the mathematical model and optimization and the spatial model of the infrastructure. Gaseous hydrogen is chosen for its lower cost of production, so it will be transported in tube trailers whose number is estimated from demand. Component-wise, the optimization results in the need of an 18MW wind power plant, a 10 MW electrolyser and a 3MW fuel cell, coupled with 5000kg storage for hydrogen. The economic analysis showed that the levelized cost of energy for the isolated communities is 0.56AUD/kWh. Overall, it is demonstrated that a green hydrogen supply chain could be feasible even in remote regions, on the conditions that hydrogen may not be locally produced.

2.2 Hydrogen Refuelling Stations

Bauer et al.[29] dedicated a paper to HRS, studied in two conditions, the first being fed with compressed gaseous hydrogen CGH_2 and the second with liquid hydrogen LH_2. HRS fed with CGH_2 requires an initial storage of around 5 to 20Mpa, compression, a high-pressure buffer and thermal management. Refueling is managed such that when the pressure level of the tank and of the FCEV reach the same value, it switches to a higher pressure tank to continue the refueling. For liquid H_2 the scheme is similar, but liquid H_2 must be evaporated through a heat exchanger HX and compressed to target pressure before delivery to the EV, or it can be cryogenically compressed with liquid hydrogen pumps. Filling of the EV tank is realized as overflowing from higher to lower pressure level realized by an expansion in an adiabatic throttle. A Matlab model is used to evaluate performance and energy consumption, by giving as inputs the required hydrogen mass flow, pressure and refueling temperature. It is concluded that LH_2 HRS is convenient compared to CGH_2, as the higher density of hydrogen allows compression work to be lower, requiring a pump instead of a compressor. Overall, the pressure level of the tank in the HRS has the main impact on the energy consumption of the HRS, although in this application the high utilization allows for avoiding boil-off and stand-by-losses.

Again, concerning the hydrogen refueling station modeling, Xu et al. [30] developed an optimization method to have fast and efficient refueling, reaching a target of 2kg/min hydrogen release. The main issue tackled is due to the rapid temperature increase that can be measured inside the FCV hydrogen cylinders during the injection and caused by the throttle valve action on hydrogen. To compensate for this effect, a cooling system must be put in place, allowing fast refueling and the safety of the FCV. Moreover, a storage cascade results in the best option to maximize the HRS efficiency and reduce specific energy consumption, although an optimization process to define the amount of storage cascade can significantly improve the overall system efficiency. Finally, the pressure ramp rate and target pressure are also subject to optimization to maximize the refueling speed while keeping operation conditions under the safety limits. HRS model is built using the numerical integration method, where in each step of the simulation the mass and energy conservation are used and then state functions are calculated. The results show that the first parameter affecting the success of the refueling process is the availability of hydrogen supply, as well as the refueling protocol, which sets a target to complete the process while remaining within the set boundary for the operation conditions, especially in terms of temperature and pressure. Concerning the FCV, they are equipped with 10 to 20kg type III tanks where hydrogen is stored at 35MPa. A precooling mechanism is put in place, generating additional energy consumption.

Hu et al.[31] found some relevant information about the technical specifics of an HRS cascade system, consisting of H_2 source, internal cooler, single stage compression, HX, nozzle and H_2 onboard cylinder. Hydrogen reaches the refueling station by tube trailers from the plant where the production takes place. It is first compressed in a diaphragm compressor, which is vastly chosen for HRSs, with a compression ratio lower than 7, making a single stage sufficient. There are commonly two options for tanks in HRSs, the seamless hydrogen storage vessels and steel belt staggered winding hydrogen storage vessels, both made of steel and therefore with good thermal conductivity. The model considers the pressure losses across all sections of the HRS. Concerning the FCEV, it is equipped with a 150L onboard tank filled with hydrogen according to the protocol in SAE J2601. During the process, the low-pressure LP tank opens first and releases hydrogen until the pressure difference between the LP tank and the nozzle drops below critical, at which point the refueling moves to the medium-pressure MP tank and finally to the high-pressure HP tank up to the target pressure value. The model results indicate some delays in the FCEV refueling due to contemporary refueling of the HRS, which means a relevant factor in HRS design would be the high capacity of its hydrogen tank, to ensure demand is supplied with minimized delay. Moreover, under certain conditions, it results that the LP hydrogen tank has a nominal working pressure similar to that of the MP tank, so that when the HRS switches from LP to MP tanks, the latter supplies only a small amount of hydrogen before it switches again to HP tank, making the system equivalent to a two-stage HRS.

Nanmaran et al.[32] also deepen the study of HRSs, by creating a mathematical model of the transportation from the hydrogen reservoir and the FCEV tank. Using MATLAB as a simulation tool, the aim of the study is to calculate the cooling power required so that the temperature registered in the EV tank is as close as possible to a target temperature. The structure of the HRS is like the ones that have been previously described, including a storage system, compression stages, a high-pressure buffer tank, a cooling system and a connection to the FCEV hydrogen tank. On the FCEV side, pressure and temperature are continuously monitored by sensors connected to the control valve, which can close in case one parameter overcomes the threshold. Storage follows normally one of two standards, one for H70 (700bar) for FC cars and one for H35 (350bar) for FC heavy vehicles. Protocol SAE J2601 regulates the gas temperature limits which range from -40°C and 85°C and regulates the dispenser pressure ranges from 87.5Mpa to 43.8 Mpa. The outcomes of the mathematical model are pressure, gas density, cooling power and temperature, in different scenarios, where the cooling temperature changes ranging from -5°C to -65°C. Results show that as the cooling temperature decreases down to -65°C, also temperature, pressure and gas density decrease. On the contrary, more cooling power is required.

Joffe et al.[33] tackled the problem of hydrogen infrastructure, especially in the downstream section reaching the final users through hydrogen refueling stations

HRS. When introducing this system in a metropolitan context such as London, some issues must be addressed. In terms of potential demand, it would likely be concentrated in the peak hours and variable throughout the day, requiring correct modeling of the load profile. The study foresees a predominant diffusion of FC buses compared to private vehicles, which implies the need for depots for said buses dispersed across the metropolitan area. Concerning the supply, the most reasonable hypothesis is that hydrogen is not produced locally but further from the city and transported to refueling stations with trucks and in liquid form. The model is supported by a nodal network structure and populated by sources of energy, conversion technologies, transportation, storage and demand. The model generates operational conditions of each component at each snapshot, considering different possible levels of demand. The results show that little storage capacity is required due to the flexibility of the main load, the FC vehicles, as they act as storage themselves.

2.3 Transportation and Distribution Methods

Exploring some specifics to transportation of hydrogen, Genovese et al.[34] published a study concerning the phases between production and final consumption of hydrogen, by modeling a H_2 fueled railway system of transport across the Italian region of Sicily, where the demand is a group of hydrogen refueling stations. Simulations are made through MATLAB and Simulink software and include most steps of the supply chain, where the molecule is produced via electrolysis to feed multiple end users, all in the mobility sectors, namely fuel cell FC electric vehicles, forklifts, bikes, buses, ferries and aircrafts. The focus is on the transportation method, a fuel cell hybrid train, which carries tube trailers to be delivered to various HRS, which is modeled with route scheduling, powertrain components, system performance information, economic evaluation and connected to both hydrogen production and fueling facility. The powertrain core is represented by the fuel cell, of which Nernst's voltage and polarization losses are known and considered in the model. The train also presents a battery composed of variable voltage sources in series with a resistor. The management of the FC train is aiming at minimizing hydrogen consumption, as the train is not only equipped with a FC but also a battery for rapid demand variations. The hydrogen fed to the HRS is liquified by first increasing the pressure to 13bar, above the critical pressure, cooling the substance to 30K and finally expanding it through a throttle valve, reducing the pressure and reaching 20K. The production facility is sized according to the actual demand, including all potential losses, revealing a specific energy consumption of 53.8kWh/kg, whereas the daily infrastructure consumption is 213MWh/day and equivalent to a 4ton/day hydrogen production.

Potential demand for hydrogen is wide and cross-sectoral, from industry to transport to grid balancing services and much more. One interesting development is in the transport sector, more specifically with hydrogen-fueled ships. Wang et al.[35] reviewed the state of the art and prospects of the technology, where hydrogen is employed mainly in a fuel cell coupled with an electric motor. At the global level, one interesting benchmark is set by the United States, where maritime fuel cells have been studied since the 1970s, although the first successful application only goes back to 2018. It was the "Water-Go-Round", a 21-meter-long ship equipped with a PEMFC, reaching a top speed of 22kn and able to carry 84 passengers. According to Bloom Energy, a large American fuel cell corporation, by 2027 fuel cells will be used to power about 100 cruise ships. In terms of future prospects, it is resulting that PEMFC and SOFC are dominant in maritime application studies and projects, the former due to its large flexibility: PEMFC is known to have a rapid start-up time and is also able to respond well to quick load variations, making it the fuel cell with best dynamic response. On the other hand, SOFCs have the advantage of not requiring a catalyst and therefore being a good choice when high output power is necessary. Higher fuel flexibility is also an interesting property of SOFCs, as they can adapt to hydrogen, natural gas and ammonia gas. The latter seems to be a promising solution for maritime applications, overcoming hydrogen in terms of safety, costs and sustainability.

2.4 Storage Systems

Focusing on storage options and modeling, Klopčič et al.[36] developed a tool which can be adapted to various modifications and operational conditions for a hydrogen storage system in a refueling station. It is an innovative choice in the realm of hydrogen studies, as it poses the base for having a common ground which can be customized based on necessities. It includes the refueling infrastructure, particularly the hydrogen tank, which is modeled in MATLAB Simulink as a series of blocks connected by buses, analogously to an electric circuit. Pressure losses and flow resistance define the pressure evolution across pipelines, valves and all other sections of the model, and this information, together with mass flow and temperature passes from one component to the next. To validate the model, laboratory experiments were conducted where hydrogen was stored in a high-pressure tank at 875bar and mass flow to the dispenser was measured with a mass flow meter. During the release of hydrogen from the dispenser, the temperature and pressure were recorded and later used as inputs for the model. The Simulink toolbox allows for rapid sizing of components and quick parameter studies of the effects of refueling conditions and protocols on final tank temperature. Some studies are centered around the upstream sections of the hydrogen supply chain, sometimes including the electricity source or the storage section following production. It is the case of the paper elaborated by Vives et al.[37], where an interesting addition is a heat recovery process exploited to facilitate hydrogen compression. The hydrogen valley comprehends the electrolyser section, where a 10 MW PEM electrolyser is employed, thereby releasing heat during its functioning. Thermal energy can be recovered up to 70% in this system to increase the efficiency, as it is used in an Organic Rankine Cycle ORC to convert medium temperature heat, at about 50-300°C into electricity. Heat recovery is applied by HX on different streams: the H_2 and O2 streams exiting the PEM stack as well as from the stack itself. ORC is a closed loop cycle where the fluid circulating is never exiting its path, and the operation conditions influence the performance of this machine. The model simulates the whole system in Aspen Plus according to three scenarios, corresponding to different levels of final hydrogen pressure after compression: 250 bar, 300 bar and 700 bar. The study aims to verify if the energy recovered in the ORC is sufficient to guarantee hydrogen compression at all pressure levels. Multiple-stage compression with intercooling is actuated allowing hydrogen to reach high-pressure levels, also simulated in Aspen Plus, starting from an initial pressure of 30 bar. The results show that the 10 MW PEM electrolyser produces 181.3 kg of H_2 per hour, which is equivalent to 28.2% of the input electricity being turned into recovered heat. For lower target pressures, some excess electricity from the ORC is sent back to the electrolyser, whereas for higher pressure targets an increasing percentage of energy must be sourced elsewhere to complete the compression process. Overall, the system efficiency for the ORC is about 8%.

Producing green hydrogen poses a challenge in terms of balancing the high variability of renewable energy sources, requiring introducing a storage system. Reußet al.[38]propose an analysis of storage options in the realm of the hydrogen supply chain. The first part of the study focuses on the various storage systems available on the market today, followed by an in-depth analysis of the GHG emissions of a hydrogen production system where seasonal storage is exploited to smooth the seasonal gap in production. The storage module can contain 60 daily productions, of which 18 daily productions are meant for seasonal storage and the remaining 42 for strategic reserve. Two types of storage are considered: a cavern where hydrogen is stored at 60-150 bar and a tank, where hydrogen can be stored in gaseous form at a wider range of pressures from 15 to 250 bar, in liquid form or as liquid organic hydrogen carrier at 1bar. The transport segment is also explored, comparing pipelines and trucks, noting that trucks present higher flexibility in reaching the endpoint and therefore an optimal choice for the distribution system, whereas pipelines are considered more efficient for the transmission network. Finally, some considerations are made on the refueling module, where each refueling station has a 200kg/day capacity and serves 2-3 vehicles per day. The results show that the most competitive combination of transport and storage technologies is seasonal storage with LOHC, for low to medium hydrogen demand. With increasing demand, tube trailer transportation combined with salt cavern storage becomes more economically sustainable.

As it has been previously discussed, ammonia is showing the potential to be the hydrogen carrier with the most developed market, due to its peculiar features. Smith et al.[39] published a study where liquid ammonia and liquid hydrogen are compared based on their low-carbon potential. The writers approached the issue by analyzing both molecules in a specific application, LH_2 and LNH_3 ships. Most relevant factors are considered, such as the tank insulation, the operating velocity of the ship, the boil-off and the carbon emissions. The study also takes a scenario approach, where some conclusions are drawn about what could be the development of such technologies in 2050. It results that liquid ammonia prevails over liquid hydrogen in terms of energy and volume delivery. Moreover, the boil-off of liquid hydrogen can be controlled and hindered best when the ship is traveling at a higher speed, compared to LNH_3. The main conclusion is that, assuming an important effort to reach carbon neutrality targets in 2050, liquid hydrogen will be more suitable than liquid ammonia in the context of fuel transport and electricity transport via energy vector, whereas for cargo transport liquid ammonia will be the optimal choice.

Chapter 3

Crave-H_2

3.1 Project Development

The Crete Aegean Hydrogen Valley of Crete (CRAVE H_2) is a currently under development European project which aims at building the entire value chain of green hydrogen on the island of Crete, situated in the Mediterranean Sea. The peculiarity of this hydrogen valley resides in its choice of locating the primary steps of the supply chain, such as the production plant and facility on the island itself, as well as its geographic scope, since the local production aims at supplying hydrogen on a regional level, with plans of reaching mainland Greece in the future.[40]
CRAVE H_2 was born in collaboration with the Clean Hydrogen Partnership, whose members are the European Union represented by the European Commission, the hydrogen and fuel cell industries represented by Hydrogen Europe and the research community represented by Europe Research. It aims to support the hydrogen economy evolution and growth, especially supporting green hydrogen from the source of its production and all along the supply chain, including storage, transmission and distribution. The Clean Hydrogen Partnership is not only supporting hydrogen development through European public funds, but it is also creating a strategic network of professional and expert figures, as well as connecting industries that are active on

the territory with the research community, to ensure a fulfilling collaboration among participants. CRAVE H_2 officially started on June 1st, 2023, receiving almost 8B€ EU contribution for its development. The project is led by Eunice Energy Group, which dominates the renewable energy market in Greece, being the only green energy power supplier. Among the main partners, De Nora will supply the last generation 4MW Dragonfly electrolyser, Ballard will design, manufacture and install a 400kW hydrogen fuel cell, whereas the electricity source will mostly come from the AIGAIO wind farm. The latter presents 582MW wind capacity and has been developed by Eunice Energy as well. Politecnico di Torino participates as well with research support, with the aim of developing a model that describes the hydrogen valley in its components and operational conditions over time. As the project officially started in June 2023, the timeline provides information about future occurrences. Building and commissioning is expected by May 2026 and the full operation of the hydrogen valley, including the correct supply and functioning of the final users.[41]

3.2 Location and Geographic Scope

The choice of building the entire value chain of hydrogen on the island of Crete is due to its abundant solar and wind resources, which are the most upstream step on the supply chain of green hydrogen. The island of Crete also results as a strategic location, as the project leader itself, Eunice Energy, is currently planning the first Greek (European) African electricity distribution interconnection. On the other hand, connection to mainland Green will be an issue to tackle when the valley is able to sustain exports from the island. It's worth noting that Crete Island is quite a peculiar location, almost unique in its characteristics, being the largest island in Greece and the fifth largest in the Mediterranean Sea, with a variety of landscapes from mountains to valleys. The vegetation is representative of the weather on the island, where typical Mediterranean weather is also very influenced by its proximity to the African continent, bringing wind that flows almost continuously. In terms of population, most large cities are found on the northern side of the island, whereas the southern side is less developed. CRAVE H_2 valley will be sited on the latter, combining the advantages of more land availability as well as the proximity to the port of Atherinolakkos. As the Hydrogen Valley plans to grow in capacity, being located near a port poses favorable conditions for future hydrogen export through shipping, as well as consumption of hydrogen as ship fuel. Choosing to locate a hydrogen valley on the island of Crete is a choice that goes beyond land and resource availability and fits in a larger project that is being carried out at the European level and aims at reaching energy independence and democracy throughout all its territories. Islands as isolated communities often must face the difficulties of unstable connection with the mainland or more civilized areas, resulting in higher costs, lower security of the system and higher climate change contribution. CRAVE H_2 aims at solving these problems, contributing to the EU clean transition as well as bringing affordable energy able to cover local yearly needs. In terms of geographic scope, the Crete-Aegean Hydrogen Valley will be initially developed for local production as well as consumption of hydrogen, focusing on the hydrogen mobility sector as well as some grid balancing services. Nevertheless, since the first step in the project development, the valley has been created to serve a larger, regional area. The sources of electricity are not located on the island, enlarging its scope already. Moreover, the plant will further expand, supplying green hydrogen to mainland Greece.

3.3 Upstream Section

The hydrogen valley structure is comprehensive of the upstream section, including the electricity sources for hydrogen production and the electrolyser, followed by the midstream section, where the production undergoes compression and is stored, to the final downstream section, where hydrogen reaches the final consumption points and the users. Starting upstream, it has been already mentioned that one peculiarity of the CRAVE H_2 is the electricity sourcing, which involves three suppliers in different regional contexts.

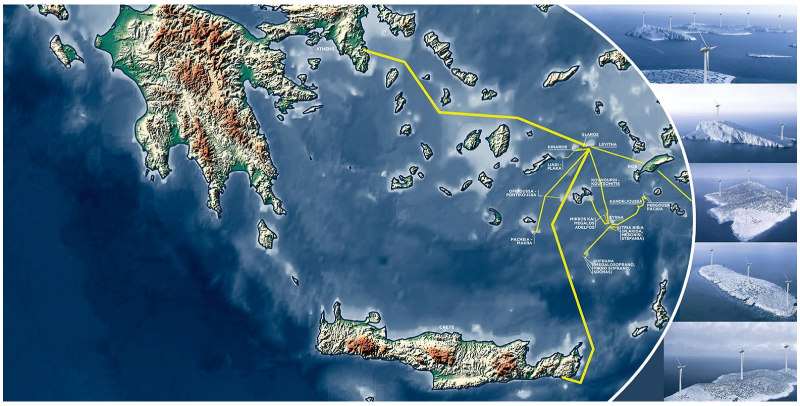

Figure 3.1. EUNICE Group - AIGAIO Project[1]

As the Hydrogen Valley planned for green hydrogen production, it requires mostly renewable energy input, which will be supplied by the large wind farm of the AIGAIO Project. It is being developed by Eunice Energy and will count a wind energy capacity of 582MW, being located across the Aegen Sea, where a multitude of small uninhabited islands provide for land availability, giving access to offshore wind resources yet avoiding the technical difficulties of offshore wind farm installations. Since 2008, when the project was started, Eunice Energy has been installing the planned 138 wind turbines, located on 23 small islands. As the map below shows, the wind farm will be provided with a simple yet efficient network of interconnections with nearby islands and mainland Greece and has been included in the European Network of Transmission Operators, ENTSO-E, ten-year development plan as the "Project 293 – Southern Aegean Interconnector (SAI)". Among these interconnections, the AIGAIO wind farm will also reach the island of Crete in the port of Atherinolakkos, where the Crete-Aegean hydrogen valley will be located, offering a direct supply of clean energy for hydrogen production.[1]

In terms of electricity sources, the plan for CRAVE H_2 is to exploit all possibilities, to ensure the RES production variability does not affect the correct functioning of the electrolyser and consequent supply of all users. For this reason, the currently existing power interconnection between mainland Greece and the island of Crete will be exploited, by simply connecting the hydrogen valley to the existing network. Concerning the transmission system, the Crete-Peloponnese interconnection is constituted by 2x140MW AC undersea cables, reaching the island on its western side, and 2x350MW DC undersea cables, connecting Attica and Heraklion. These power connections are managed by the Greek Transmission System Operator (TSO), Independent Power Transmission Operator IPTO, who announced a strengthening of this interconnection, planning the installation of HVDC undersea cables. Furthermore, the island itself is equipped with the Atherinolakkos power plant, which has a capacity of 204MW and, together with the power interconnection with the mainland, will serve as backup for the hydrogen valley. These two assets will be supplying electricity to the electrolyser only in emergency situations since they cannot ensure to be supplying electricity from renewable energy sources.[42]

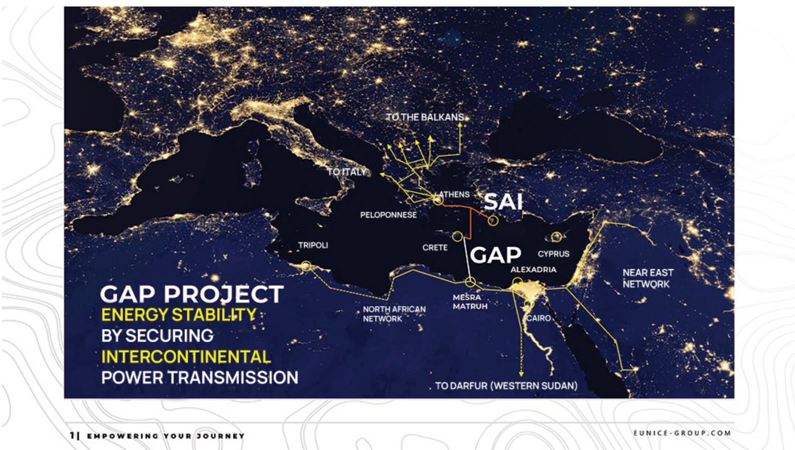

Figure 3.2. Greece Africa Power Interconnector (GAP)[2]

Finally, to increase the reliability of the system and ensure continuity in the electricity supply, the Crete-Aegean Hydrogen Vally will be connected to the currently under development Greece Africa Power Interconnection (GAP), with 2000MW capacity, to be completed in 2030. The project was announced by Eunice Energy in March 2024 as part of a larger expansion plan for the Greek power system, which will include the Southern Aegean Interconnector (SAI), a DC transmission link from the island of Crete to mainland Greece of 600-800MW. The combination of the two will generate the shortest interconnection from Africa to Greece, bringing down the cost of transmission. Some advantages are also related to the presence of the island of Crete, which indicates a low steepness zone which facilitates the installation and maintenance. Moreover, it will further enhance Crete's position as an energy hub in the Eastern Mediterranean, with power transmission capacity with three continents. As more renewable energy will be installed in African countries, it will be possible to lower the production costs of green hydrogen in Crete. Completing the power network picture concerning the island of Crete, it currently presents about 13GW of renewable energy plants, which are projected to increase to 28GW by 2030.[2]

3.4 Midstream Section

In the midstream section of the hydrogen supply chain, the production facility is constituted by an electrolyser, fed with electricity from the above-mentioned sources and water. The Dragonfly electrolyser, of the alkaline type, has a capacity of 4MW and is able to produce 500tons of hydrogen per year. The supplier is Industrie De Nora S.p.A, which is an Italian company in the electrochemical sector. De Nora was founded in 1923 and specializes in green hydrogen production technologies, especially Alkaline Water Electrolysis AWE. With extensive R&D efforts, they developed an AWE device which maximizes the operating current density while reducing the power consumption, compensating for the known downsides of AWE. Improvements have been made also in terms of dynamicity and flexibility, fundamental requirements for RES coupling. Finally, De Nora technology is Noble Metals-free, lowering the investment costs.

At the electrolyser outlet, produced hydrogen has a pressure of 30bar, too low to allow its storage. Moreover, hydrogen is produced in gaseous form, but liquid hydrogen storage requires an in-between step of liquefaction. As far as the currently released material on the Crete-Aegean Hydrogen Valley, the compression/liquefaction and storage steps have not been clearly defined yet, although it is reasonable to assume that among all storage possibilities for hydrogen, which have been explored in the first chapter, compression and liquefaction are the most likely to be realized.[3]

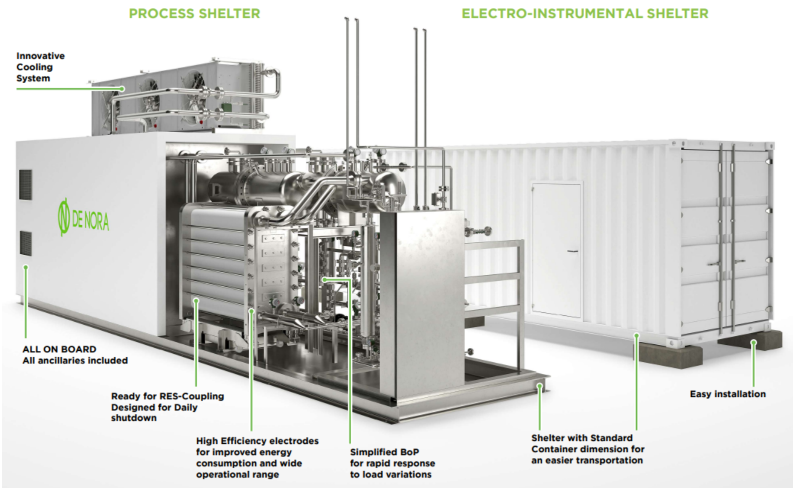

Figure 3.3. De Nora Dragonfly Electrolyser[3]

3.5 Downstream Section

The downstream section of the supply chain of hydrogen in the Crete-Aegean Hydrogen Valley, is composed of several final users. At the initial stage of the hydrogen valley installation and operation, the production capacity will be enough to supply only a few of them. Nevertheless, as the electrolyser size and storage capacity are increased, further developments in this section will be possible. The largest demand quota is assigned to the transportation sector, as the valley will supply a fleet of hydrogen buses, by the company Union Coach Services, which has been present in the tourist market for many years. The choice of supplying a transportation user implies the need for some further infrastructure to be developed on the island or at least around the hydrogen valley, namely the refueling stations, where hydrogen is stored and ready to be transferred to the onboard hydrogen tanks. The initial project also comprises the installation of a fuel cell, which is fed with hydrogen from storage to be converted back into electricity. The aim of installing a 0.4MWel PEM fuel cell, is that it can serve as an immediate electricity supply, behaving as a daily or weekly storage. Disposing of this powerful instrument implies increasing the electricity network stability and adequacy, by providing fundamental energy balancing services. The fuel cell can draw hydrogen from the storage whenever a frequency imbalance is recorded on the electricity grid, as well as in emergency situations. The PEM fuel cell will be provided by Ballard, who will design, manufacture and install a state-of-the-art fuel cell.[43] PEM fuel cells are currently the most flexible technology available in this field, allowing for RES variability compensation and fast response to necessities. As mentioned, future expansion of the valley will be mainly oriented towards increasing the range of possible hydrogen users. The maritime sector seems to be an interesting solution, where hydrogen ships can help decrease the high sector emissions. These ships are equipped with an onboard fuel cell and hydrogen storage, which is filled with hydrogen before leaving the port. Once again, the strategic location of the Crete-Aegean Hydrogen Valley, close to the port of Atherinolakkos, will simplify the development of this section. As for the hydrogen buses, ship refueling requires infrastructure and station installation. Finally, an increase in hydrogen production and further development of the valley could generate a surplus of hydrogen which can be destined for industrial use. The industrial fabric of Crete Island is not quite developed, and the island's economy will likely continue to be based on tourism and agriculture. Nevertheless, shipping can become a sufficient means to transport hydrogen to mainland Greece, making it available for the industry sector in Europe. Hydrogen can be exploited both as feedstock for the chemical and refinery industries, as well as fuel for the Hard-to-Abate sectors, such as steel making.

The scheme below represents the current plan for the Crete-Aegean hydrogen valley, as described in this chapter.

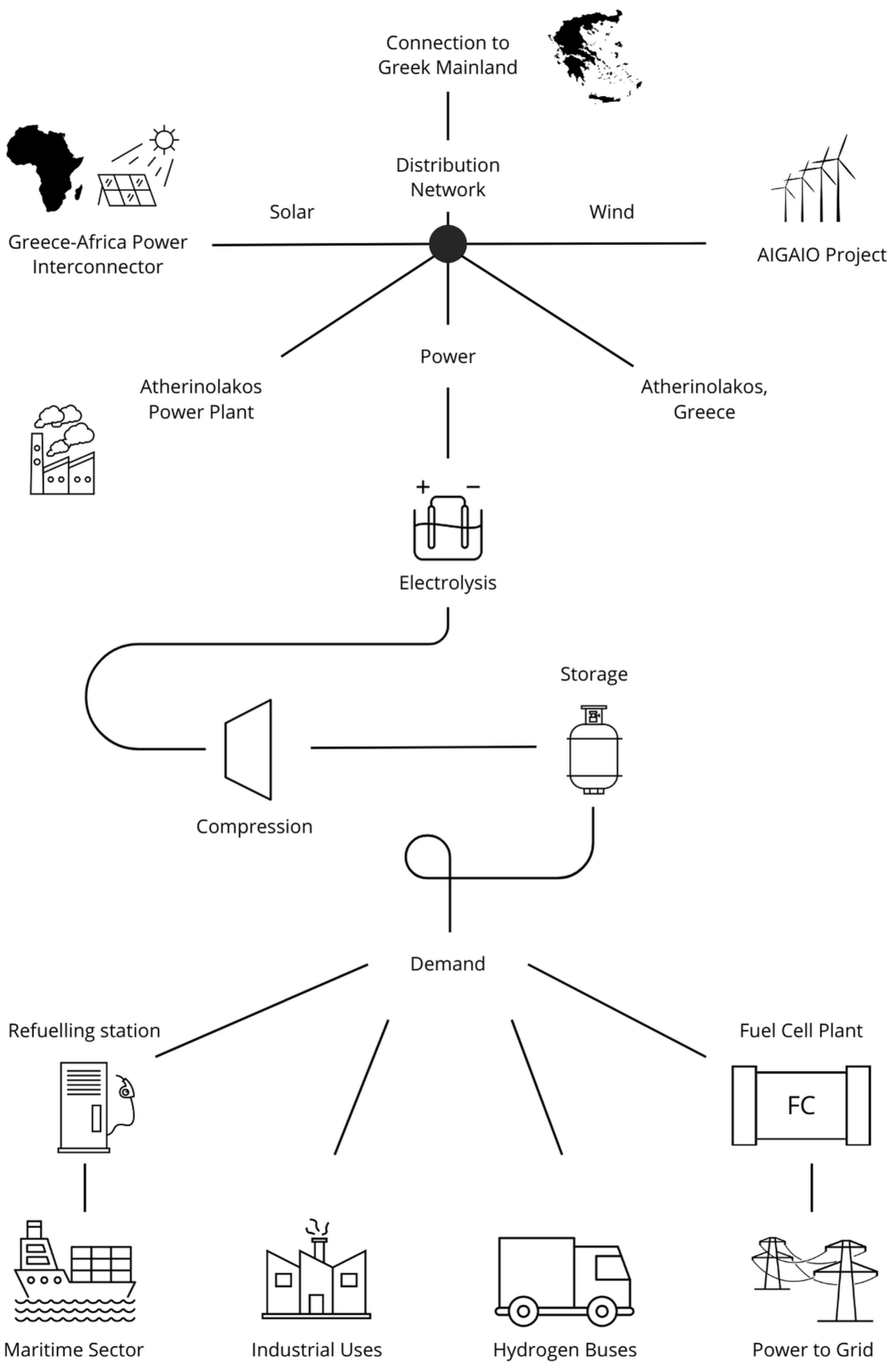

Figure 3.4. $CRAVEH_2$ Hydrogen Valley Scheme

Chapter 4

Data Collection

The aim of this study is to develop a model of the Crete-Aegean hydrogen valley, through which it is possible to govern the functioning of each component in the valley in order to optimize the electricity consumption for hydrogen production and the dispatching to the final users. The model is built on the valley network itself, therefore contains each component and its characteristics. In this chapter, a run-through of all the input data for the model will be given, including already known data as well as preliminary information that has been collected in literature to obviate technical specifications that at this stage of the study are not yet available. Most research has been conducted to collect data about the economics of the project, namely Capital Expenditures CapEx and Operational Expenditures OpEx, where the former refers to the upfront costs that must be sustained to acquire the components of the valley, whereas the latter refers to the variable costs associated to the daily functioning and maintenance of the valley.

4.1 PV Plant

Starting off with the electricity supply, a preliminary analysis of the CapEx and OpEx of the electricity supply is required, especially concerning PV and Wind resources. Despite the final arrangements of the plant, which will not directly include PV and Wind plants, these numbers are needed to derive the final electricity cost as seen from the valley point of view. Concerning PV CapEx, all costs refer to the single kW and they include the cost of the modules with the relative inverters, the cost of mounting and installation, which account for the larger portion of the total, plus some extra costs related to safety and monitoring. A relevant portion of the CapEx is related to the cost of connecting the plant to the electricity network, as well as the cost of cables and wires. Finally, some soft costs must be included, to account for the plant project, permits and some other components. OpEx for PV plants are costs associated with the technical and commercial operation of the plant, the insurance and both preventive and corrective maintenance. A small contribution related to greenkeeping can be added if needed. All mentioned information related to PV plants has been collected from the report published in 2023 by IRENA and titled “Renewable Power Generation Costs” [4] where a rundown of all costs associated with renewable energy is collected. In terms of PV, the study highlights as the main trend the decline in PV module costs in Europe, which has decreased by 91% between 2022 and 2009. It is also noted that this trend slightly deviated in 2021 due to lower material availability related to ongoing geopolitical situations. All mentioned costs with the respective values found in the IRENA report are summarized in the table below.

4.2 Wind Plant

Concerning the other RES plant made available to the Hydrogen Valley, the AIGAIO wind farm, CapEx and OpEx are found in the publication by NREL about the “2022

Category	Subcategory	Cost	Unit
CapEx	Modules	255	€/kW
	Inverters	38	€/kW
	Mounting	85	€/kW
	Grid Connection	85	€/kW
	Cabling and Wiring	19	€/kW
	Safety	28	€/kW
	Monitoring	10	€/kW
	Installation	290	€/kW
	Soft Costs	290	€/kW
	Total	1100	€/kW
OpEx	Technical Operation	3	€/kW/y
	Insurance	2	€/kW/y
	Preventive Maintenance	2	€/kW/y
	Corrective Maintenance	0.1	€/kW/y
	Commercial Operation	1	€/kW/y
	Greenkeeping	0.05	€/kW/y
	Total	8.15	€/kW/y

Table 4.1. IRENA - Renewable Power Generation Costs[4]

Cost of Wind Energy Review", as part of the National Renewable Energy Laboratory of 2023[5]. The analysis covers both land-based and offshore wind plants, although for the purpose of this study, only the former is of interest. The cost breakdown highlights three categories of contributions, starting from the largest portion which is the turbine CapEx (48%) of the total. The turbine CapEx includes the rotor, nacelle and tower costs. The second category is the Balance of System BoS CapEx, where smaller but more numerous contributions are present: the project development and engineering, the installation with site access and staging, the foundation costs and the electrical infrastructure costs. The latter, as seen for the PV plant, includes the cable and wires as well as the grid connection to the electrical network. Finally, the financial CapEx is constituted by the contingency and the construction finance.

The contributions are summed to obtain a total CapEx for land-based wind farms of about 1300€/kW. The land-based wind farm Operational Expenditures are quite a variable contribution, which normally includes both operation and maintenance of the farm. The NREL publication indicates an estimated OpEx of around 40€/kW per year, although this number is in the higher part of the range. Considering the complexity of the AIGAIO farm, being installed on small uninhabited islands of the Aegean Sea, it's plausible to assume the maintenance costs will be slightly higher than the average due to the difficulties in accessing the turbines. All mentioned costs with the respective values found in the NREL report are summarized in the table below.

Category	**Subcategory**	**Cost**	**Unit**
CapEx	Rotor	280	€/kW
	Nacelle	396	€/kW
	Tower	229	€/kW
	Engineering	30	€/kW
	Project Management	11	€/kW
	Foundation	100	€/kW
	Site access	39	€/kW
	Assembly & Installation	83	€/kW
	Electrical Infrastructure	60	€/kW
	Construction Finance	95	€/kW
	Contingency	45	€/kW
	Wind Turbine Transport	160	€/kW

	Contingency	107	€/kW
	Total	1635	€/kW
OpEx	**Total**	40	€/kW/y

Table 4.2: NREL - 2022 Cost of Wind Energy Review[5]

4.3 Electrolyser

The cost analysis for electrolysers requires an introduction to the current status of the electrolysers market. Green hydrogen production technologies are maintaining considerably higher costs compared to fuel-based ones, although they have been on the market for quite some time and are nowadays showing technology maturity and availability. Nevertheless, they present a fair potential for cost reduction associated with the automation of their supply chain and production, the increase in the availability of components, the expected increase in market demand and deployment for energy storage. Among electrolysers, the most expensive technology is the PEM water electrolyser, which as of 2022 is showing 50%-60% higher costs compared to the alkaline one. Anion Exchange Membranes AEM electrolysers and SOEC costs are more challenging to define, due to a more contained presence on the market and a smaller pool of manufacturers. Despite the technology being mature, some components of these two types of electrolysers are still at the laboratory scale, and not yet being fully commercialized. In terms of cost estimation, challenges are posed by low data availability as well as inconsistent data on the stack, balance of plant and full system costs. In the IRENA report "Green Hydrogen Cost Reduction"[44], a thorough and multilevel analysis of electrolysis costs is conducted, starting from the single cell unit which is the core of the electrolyser, moving to the stack costs, which represents about 40%-50% of the total, finally reaching the system costs, including all the peripherals responsible for operating the electrolyser, excluding any compression and storage system. Some examples of components for the Balance of Plant are the rectifier and water purification unit. The IRENA report provides an in-depth cost breakdown, for both PEM and alkaline electrolysers, although the latter will be more interesting to analyze as it is the chosen technology for the Crete hydrogen valley. The main distinction being made is between the stack components and the balance of plant, where the former is, in turn, split into the major portion dedicated to the diaphragm/electrode package, covering up to 57% of the stack costs, and smaller contributions including the porous transport layer PLT, the structural layers, the sealing and frames, the bipolar plates BL and finally the assembly and end plates. On the other hand, the balance of plants includes a 50% contribution by the power supply, to which the water circulation system, the hydrogen processing (compression and storage) and the cooling sections are added. For numerical values, the Clean Hydrogen Monitor, published in 2023[6], provides the electrolysis system costs for a 10MW alkaline electrolysis system. The underlying assumptions about the equivalent hours, the network costs, taxes and fees. The main findings are reported in the table below.

Category	Subcategory	Cost	Unit
CapEx	Electrolyser	1250	€/kW
	Economic lifetime	30	years
OpEx	Stack Replacement Cost	35% CapEx	
	Energy Consumption	52.4	kWh/kg
	Stack Durability	80000	hours
	Other	2% CapEx	

Table 4.3: Clean Hydrogen Monitor Data[6]

4.4 Hydrogen Storage

Downstream of the electrolyser, the hydrogen storage system is once again a challenging component in terms of cost analysis. As for electrolysers, cost-related information is confidential and rarely shared by manufacturers. For a preliminary analysis, the Clean Hydrogen Partnership set targets in terms of the main KPIs for hydrogen, including the €/kg cost of hydrogen storage. The case of interest is aboveground compressed storage, for which the SoA as of 2020 is reported to be 750€/kg. Said targets are set for 2024 to 700€/kg, decreasing up to 600€/kg in 2030[45]. As a secondary source, it is possible to refer to the IEA Future of Hydrogen report, more specifically to the Annex dedicated to the assumption made, where compressed hydrogen storage is considered to have a capital cost of 1850€/kWe and OpEx costs of 73€/kWe[46].

4.5 Fuel Cell

Among the final users, the main concern is the installation of the fuel cell for the conversion of hydrogen into electricity for grid balancing services and the installation of the hydrogen refueling station to supply the FC bus fleet, whose cost information can be useful in the future for the ships refueling station. Fuel cells are mature technologies, where design parameters vary according to the type (PEM, SOFC, etc). PEM fuel cells are the most common choice as they guarantee high efficiency as well as flexibility, since their operational profile can adapt to cover peaks during the day. Moreover, quick startup and low maintenance costs are some other interesting characteristics of PEM fuel cells. Being the technology of choice for the Crete-Aegean hydrogen valley, the cost analysis will focus on PEM fuel cells. Cigolotti et al published a study under the IEA Technology Collaboration Programme, titled "Stationary Fuel Cell Applications"[47], where a cost breakdown for PEM fuel cells is given. The main contribution is given by the stack, followed by Balance of Plant and periphery costs. Smaller contributions are related to the reformer, inverter, service and backup components. The stack includes the assembly, test and conditioning costs, the Membrane Electrodes Assembly MEA, the bipolar plates, the gasket and the end plates. In terms of literature references for fuel cell costs, in their study about power-to-hydrogen systems, Daraei et al. [48] refers to a capital cost for PEMFC of 3000€/kW and yearly OpEx equal to 1% of CapEx. The paper written by Patel et al. [49], indicates similar but lower values, where CapEx settles at 2960$/kW and OpEx values are 1.5% of CapEx.

4.6 FC Bus Fleet

An analysis of technical requirements is necessary to approach the topic of the FC bus fleet. The first information found in the literature concerns hydrogen consumption, fundamental to finding the overall hydrogen demand for the hydrogen refueling station. Caponi et al.[50] paper about hydrogen refueling stations includes the analysis of the hydrogen consumption of FC buses, finding an average value of 0.07kg/km. In the study "Techno-economic assessment of green hydrogen valley providing multiple end-users", Petrollese et al. [22] assumes a specific hydrogen consumption of 0.15kg/km. Ballard[51] published a study on refueling for fuel cell bus fleets, divided into three phases based on the project development. In the first phase, a demonstration fleet of 5 FC buses is considered, each carrying up to 40 kg of hydrogen, a quantity too low to justify a complex refueling system such as for liquid hydrogen. The second phase is the pilot deployment, where 5 to 20 buses are considered. At this stage, liquid hydrogen becomes economically viable, as the refueling station supplies 125-500kg of hydrogen per day. Finally, commercial deployment means a fleet of more than 20 FC buses. For this study, Ballard considers a specific hydrogen consumption of 0.078kg/km. As mentioned, another important information is the onboard tank capacity, which is considered 40kg in Ballard's study. A similar value has been announced by Toyota for its FC bus CaetanoBus[52] which is equipped with a total hydrogen capacity of 37.5kg. Hyundai's ELEC CITY [53] fuel cell bus is provided with five hydrogen tanks for a total storage capacity of 34kg, providing about 500km of range, which confirms the assumption of 0.07kg/km as specific consumption.

4.7 BESS

Some final considerations should be made on the topic of batteries. Despite not being currently included in the Hydrogen Valley project, the flexibility offered by a battery storage system when coupled with renewable energy sources makes it plausible to foresee a future installation. In 2023 NREL published a study on cost projections for utility-scale battery storages[54], based on a collection of data from various studies made between 2020 and 2023. The analysis is made on lithium-ion batteries, considering three scenarios: low, mid and high-cost projections, with a starting point of \$482/kWh as of 2022. Projections for 2030 for the three scenarios are respectively \$255/kWh, \$326/kWh, and \$403/kWh. Some uncertainties must be considered as the cost projections highly depend on the chosen starting point. According to the IEA study "Batteries and Secure Energy Transition"[55], lithium-ion battery costs have dropped in the last decade from 800/kWh to about 140\$/kWh in 2023, as technology became more mature. It implies a higher share of raw materials costs in the total, therefore making the battery's costs highly dependent on the availability and price of critical minerals.

Chapter 5

Model description

The aim of this study is to contribute to the development of a flexible tool for the techno-economic simulation of the Hydrogen Valley, which requires modeling of all deployed technologies and components, from the production to final users. The tool will allow to perform the optimization of the global system design, identifying the optimal configuration by imposing objective functions. In recent years the field of energy modeling has seen a rapid development driven by the necessity to adapt to the increasing complexity of power systems. Many factors played a part in this context, starting with the electrification of energy demand, the diffusion of decentralized RES characterized by high variability and fluctuations, the need for decarbonization on the demand side, as well as the introduction of prosumers, network users which can be both consumers and producers.

5.1 PyPSA

The modeling of complex energy systems is usually achieved using Python as a programming environment, having access to PyPSA. PyPSA stands for Phyton for Power Systems Analysis, and it is a toolbox allowing modeling and optimization of said systems over multiple time periods. The power system is represented with

PyPSA as a network of interconnected components, where the latter can be

- Buses, representing the electric network nodes to which all components are attached

- Loads, representing fixed power demand

- Generators, representing any power source with specified power availability

- Stores, allowing to shift of power among time periods and considering energy leakage

- Storage units, behaving like stores with additional efficiency losses and power limits.

- Lines are the interconnections between buses and guarantee power flows among them according to the power imbalances

- Links are similar to lines, except for the possibility to set the active power flow across them

- Carriers are the energy carriers present in the network, such as wind, PV, electricity etc.

Concerning energy flows, the entry points for energy are the generators, stores and storage units, whereas the exit points are the loads, stores and storage units, as well as in links and lines where efficiency is lower than one and energy is dissipated.

Once the network is set and populated with all components, PyPSA is able to solve the power flow equations to obtain voltages and power flows at all points in the network. An optimization problem can be set and solved as well and by default it is formulated to minimize the total system costs, considering both variable and fixed costs related to the generators, storage systems and transmission.

To create a power system with PyPSA, the first step is to generate the container where are components will be located, that is using the $pypsa.Network$ command. Each component can then be added to the network, together with its defining parameters. Information about the network is stored depending on the type of data. Static data is stored using the object $panda.DataFrame$ where each column is associated with a relevant parameter or information, such as the bus to which a component is attached or its efficiency. Static data can be accessed by referring to $n.component_name$. Time-varying data required multiple values to be stored, one for each snapshot considered, and therefore it can be accessed referring to $n.component\_name\_t$.

The scheme below indicates the topology of the network representing the current plan for the Crete-Aegean Hydrogen Valley.

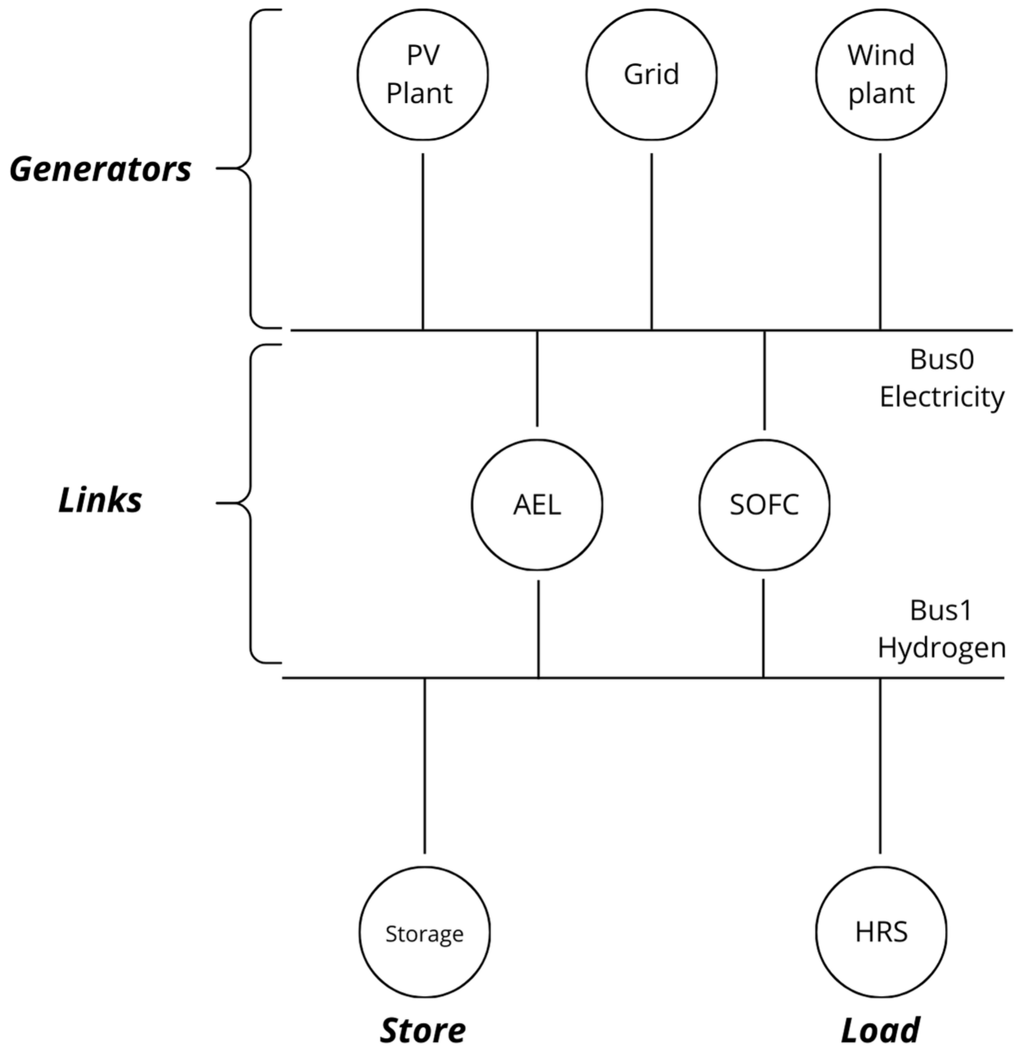

Figure 5.1. $CRAVEH_2$ Hydrogen Valley Network Scheme

5.2 Components

The PyPSA command *network.add* is employed to add all necessary components to the network. For this section, a brief description of the components will be given, in terms of their classification in the PyPSA network and of their main parameters.

Starting with the network structure, two nodes are employed to represent the two energy carriers in the system, electricity and hydrogen. By adding the electricity and the hydrogen buses to the network, the topography simplifies to two sections separating the components dealing with only hydrogen and those dealing with only electricity in their system. Most components can now be easily allocated to either of them, making the exception for the electrolyser and fuel cell, which should be attached to both the electricity and the hydrogen buses.

In the upstream section of the hydrogen valley, there are the RES plants supplying green electricity to the electrolyser. The PV and wind plants have similar characteristics and are therefore discussed together. They are classified as $Generators$ as they provide input electricity to the network, which implies being exclusively attached to the electricity bus. For $Generators$, PyPSA allows specifications about the prime mover energy which for PV and wind plants will be respectively PV and $Wind$. They are furthermore provided with information about the nominal power as well as capital and marginal costs. Marginal costs for PV and wind plants represent the cost of producing one extra electricity unit, which for the RES plant is 0€/kWh, since no fuel supply is required. All costs associated with RES plants are taken into account in CapEx and OpEx values, which are combined with the capital cost according to the following formula:

$$CapitalCost = \frac{CapEx}{CFR} + OpEx$$

Where CFR is the Capital Recovery Factor, used to convert the initial CapEx expense into a series of equal annual cash flows for the entire project duration. Its value depends on the discount rate, according to the following formula:

$$CFR = \frac{i}{(1 - (1 + i)^{(-n)})}$$

Where i is the discount rate and n is the plant lifetime.

The chosen data is summarized in the table below.

Component	**Parameter**	**Value**	**Unit**
Project	Discount rate	0.05	
	Economic lifetime	20	years
PV plant	Nominal power	4000	kW
Wind plant	Nominal power	1000	kW

Table 5.1: PV and Wind Plants Information

The final *Generator* considered in the system is the grid, attached to the electricity bus as well, and for which the carrier is considered *Grid* for PyPSA classification.

Moving to the hydrogen bus, it is possible to find all the loads and hydrogen storage attached to it. The hydrogen storage is classified as PyPSA *Store* and characterized by *e_min* and *e_max* respectively referring to the minimum and maximum State of Charge SoC of the hydrogen storage, as well as the *e_initial* which is the initial energy stored. The latter is required to satisfy the conditions of the system at the beginning of the simulation, as well as to have a more realistic representation of the network. As for the PV and wind plants, marginal and capital costs are provided. Finally, for the *Store* type of component, it is possible to specify whether the initial energy in the storage can be considered as the final energy for the group of snapshots in the optimization. Information about the storage is clarified below.

Component	**Parameter**	**Value**	**Unit**
Hydrogen Storage	Minimum SoC	0.02	
	Maximum SoC	1	
	Initial energy	1000	kWh

Table 5.2: Hydrogen Storage Information

Concerning the loads, a preliminary version of the modeling tool is built considering the HRS demand, calculated based on the required refueling of the FC bus fleet.

Finally, the links between buses must be defined. The conversion between the energy carriers, electricity and hydrogen, occurs through the electrolyser and the fuel cell, therefore defined as PyPSA *Link*. This category of components is defined by assigning bus_0 and bus_1 as the exiting and entering nodes in the network, as well as the nominal power, efficiency, capital and marginal costs. Information about the electrolyser and fuel cell is summarized in the table below.

Component	**Parameter**	**Value**	**Unit**
Electrolyser	Nominal Power	4000	kW
	Efficiency	0.6	
Fuel Cell	Nominal Power	400	kW
	Efficiency	0.6	

Table 5.3: Electrolyser and Fuel Cell Information

5.3 Time-Varying Data

The hydrogen valley model should be able to simulate the functioning of each component at each time step, where the simulation is carried out through an entire year. To achieve this goal, it is necessary to have external data available about the energy streams entering and exiting the system. Upstream of the electrolyser, the PV and wind plants will produce electricity following a weather and wind-dependent profile, which should be provided to the model.

Concerning the wind data, an innovative tool has been developed and described in the paper published by Staffel et al. [**?**]. *Renewable.ninjia*[**?**] is the resulting database which is used to run simulations about the hourly power production in wind farms across Europe. Input information for this tool is the location of the wind farm, the capacity and height, as well as the model of the wind turbine.

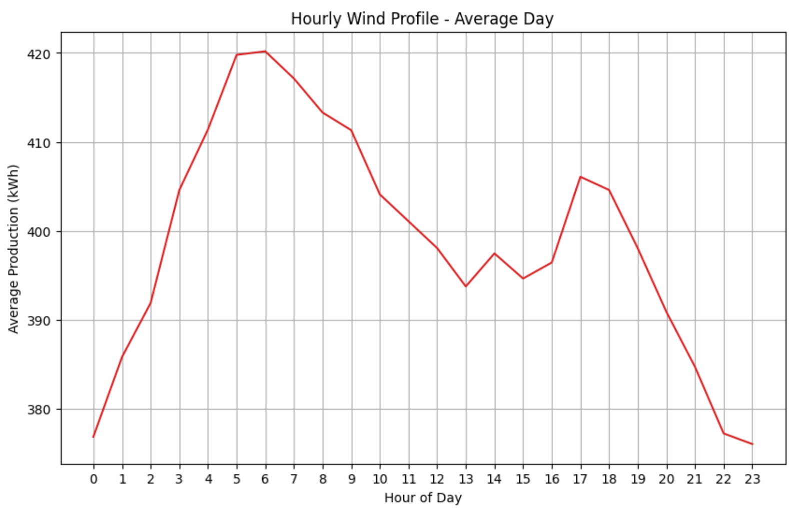

Figure 5.2. Wind Profile

Another set of input data regards the PV plant production and is downloaded from PVGIS, a web application that is commonly used to collect data about the hourly energy production of solar radiation and photovoltaic energy system. PVGIS requires the user to provide information about the geographical location, the electric network connection of the PV plant (grid-connected, off-grid), the technology, the nominal power and further specifications about the mounting. In the CRAVE H_2 project the assumption made on the PV system is to be grid-connected as the project does not include a PV plant dedicated to the Hydrogen Valley. In the condition of grid-connected PV, the calculations of production are made assuming all energy can be sent to the grid and no local consumption is taken into account.

Specifications chosen for this case study are reported in the table below, followed by the resulting average daily PV production profile.

Parameter	**Value**
Latitude	35.003°
Longitude	26.139°
Slope	30°
Azimuth	-10°
System Loss	14%

Table 5.4: PVGIS Input Information

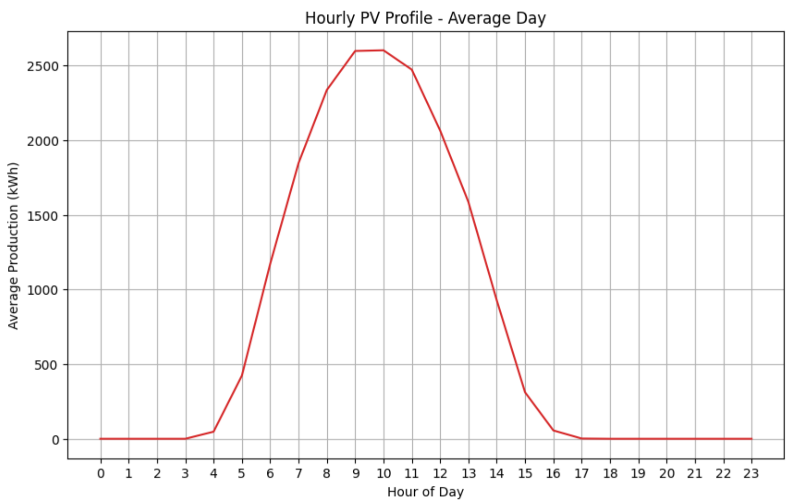

Figure 5.3. PV Profile

5.4 Network Optimization

PyPSA system optimization is based on the minimization of an objective function which determines the total system costs, including both capital and operation costs for each component of the network. The optimization of therefore carried out aiming at having the minimum total system cost in each snapshot of the simulation. The objective function is reported below for reference:

$$\sum_{n,s} c_{n,s}\bar{g}_{n,s} \quad + \quad \sum_{n,s} c_{n,s}\bar{h}_{n,s} \quad + \quad \sum_{l} c_l F_l \quad +$$
$$+ \quad \sum_{t} w_t[\sum_{n,s} o_{n,s,t} g_{n,s,t} \quad + \quad \sum_{n,s,t} o_{n,s,t} h_{n,s,t}] \quad + \quad \sum_{t}[suc_{n,s,t} + sdc_{n,s,t}]$$

n: label the buses

t: label the snapshots

l: label the branches

s: label the different generator/storage types at each bus

$c_{s,n}$: capital cost of extending genrator nominal power by 1MW

$o_{n,s}$: marginal cost of dispatch generator for 1MW

w_t: weighting of time t in th objective function

$g_{n,s,t}$: dispatch of generator s at bus n and time t

$\bar{g}_{n,s}$: nominal power of generator s at bus n

$h_{n,s,t}$: dispatch of storage s at bus n and time t

$\bar{h}_{n,s}$: nominal power of storage s at bus n

$f_{l,t}$: flow of power in branch l at time t

F_l : capacity of branch l

$suc_{n,s,t}$: start-up cost of generator s starting at time t

$sdc_{n,s,t}$: shut-down cost of generator s shut down at time t

In terms of generators, the optimization guarantees nominal power and dispatchment constraints, by imposing the availability of the actual associated power source, for example a PV or wind plant.

The same process is valid also for storage units, such that the storage dispatch and uptake must not exceed the nominal power.

For links, the flow over line l at time t must not exceed the nominal power of the branch, but it can be both positive when power i withdrawn from the link, and negative when power is injected in the link. The optimization takes into account the efficiency of the link.

The energy flow balances then play a key role in the optimization process as they guarantee the balances at each bus n for each time t.

Chapter 6

Scenario Analysis

Concerning the $CraveH_2$ project, it is relevant to analyze the possible developments in terms of the design and operation of the hydrogen valley. As some components such as the electrolyser are, at this stage, very well defined, other parameters and factors are yet to be investigated.

The objective of this study is to explore in greater depth the potential pathways for project design development and to analyze the corresponding outcomes generated by the model.

Starting from the upstream section in the hydrogen valley, the input electricity has been modeled by three generators, of which one is reperesenting a PV plant and another a wind plant. For both of them, the size is a design parameter which influences the output and could vary based on made assumptions. As previously mentioned, the upstream section involves the streams of electricity that will serve as input for the electrolyser functioning. It implies the Hydrogen Valley will have a connection to the grid and green power from PV and wind plants will be supplied. At the model level, the input streams can be modeled in various ways, as in reality the grid connection cannot be differentiated based on the production plant of origin. The chosen path is to model PV and wind production plants as fictitious plants associated with the Hydrogen Valley, built in the vicinity of the electrolyser and operating only to serve the hydrogen production.

From a component design standpoint, the project envisions the deployment of a hydrogen storage system. However, the precise scale and capacity of this system are expected to be significantly influenced by the final demand levels within the Hydrogen Valley. As the project progresses, its development trajectory is anticipated to broaden access to locally produced hydrogen, extending its availability to a larger range of users across various sectors, including maritime and industrial applications. This anticipated expansion into multiple sectors is likely to create diverse and evolving storage requirements, opening up the need for a more detailed investigation into storage system configurations and capacities that can accommodate these emerging demands. Through such an adaptable approach, the project aims to ensure that the storage infrastructure will be capable of supporting a variety of user needs as the hydrogen ecosystem grows and evolves.

As indicated in the previous paragraph, the project's design approach considers the evolving nature of hydrogen demand within the valley. It is essential to account for various demand scenarios throughout the simulation year, as this will allow for a more robust assessment of potential fluctuations in the demand profile and support the development of a storage system capable of adapting to these dynamic conditions.

Three scenarios have been developed on the basis of different possible demand profile for the hydrogen valley, taking into account the expected evolution of hydrogen in various sector. The *Low Demand Scenario* is characterized by the contribution of the FC bus fleet, whereas the *Intermediate Demand Scenario* accounts for a possible introduction of hydrogen into FC ships. Finally, the *High Demand Scenario* introduces an extra load representing hydrogen shipped to mainland Greece to supply the industrial sector.

6.1 Low Demand Scenario

In the first scenario taken under analysis, the hydrogen valley is fully operative but limited to the demand requirements of the bus fleet described in previous chapters. It is assumed that the valley is in the first stage of operation, not yet equipped to supply large users.

Demand for this scenario is represented by the Fc bus fleet and the demand profile is built following the example of the Ballard study [51] already mentioned and described in Chapter 4. Three phases of development are analyzed to better represent the reality of the Hydrogen Valley development, where the FC bus fleet is increased from a demonstration project of 5 FC buses to commercial deployment with 20 FC buses. According to the results found in Chapter 4, the following table summarizes the main assumptions made for the design of each FC bus system.

Parameter	**Value**	**Unit**
Onboard tank capacity	40	kg
Specific consumption	0.07	kg/km
Daily distance	100	km/day

Table 6.1: FC Bus Parameters

Considering the assumed data, the daily demand associated with each FC bus is

$$Demand_{daily} = 0.07km/km * 100km/day = 7kg/day$$

Each FC bus will require at least one refueling per day, in order to satisfy the daily demand and allowing to have at its disposal a minimum percentage of hydrogen at all times. Fixing the minimum percentage of hydrogen availability to 25% of the onboard storage capacity implies each FC bus will represent a daily demand for the HRS of 7kg of hydrogen.

The daily demand per bus is translated to kWh through the lower heating value of hydrogen which is $33.33kWh/kg$ and multiplied by the bus number in the fleet. It is assumed that refueling occurs in three moments along the day, allowing for the daily demand to be more equally distributed, but anyways focused in the central hours of the day when PV production is more probable.

The following plot represents the FC bus fleet demand each day, depending varying with the assumed number of buses.

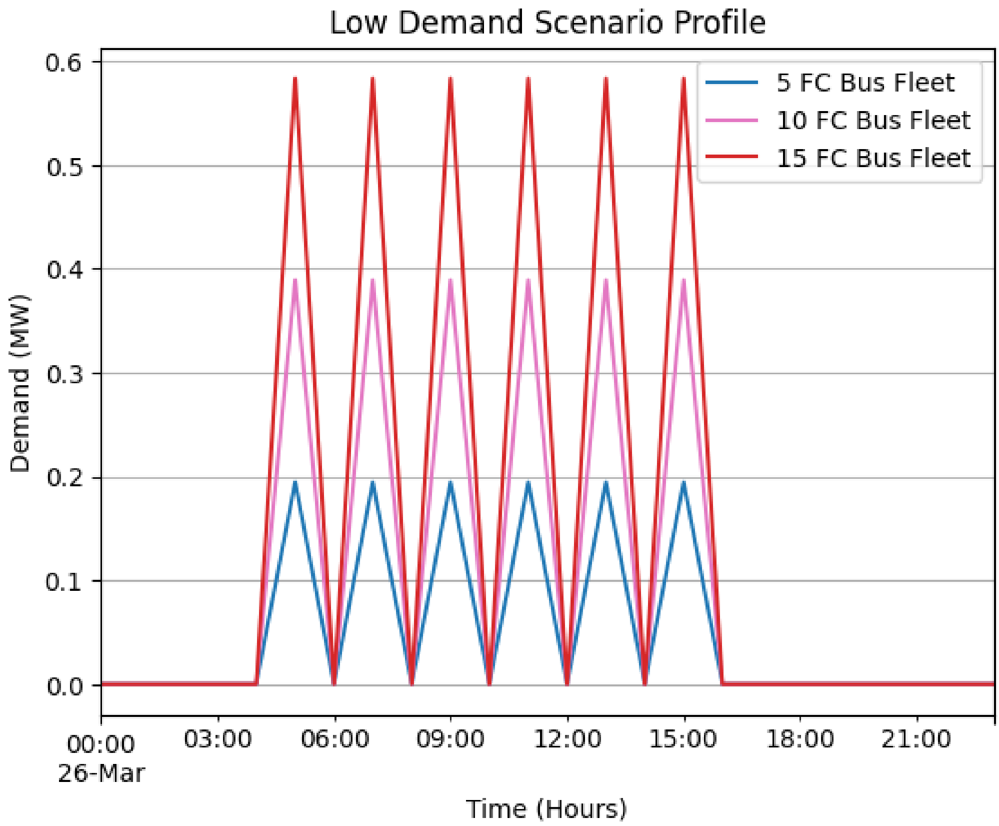

Figure 6.1. FC Bus Fleet Hydrogen Demand Profile

The scenario construction starts with the definition of the demand profile, represented in Figure 6.1. Despite the progressive increase of the number of FC buses, the demand profile remains limited, allowing the other components in the Hydrogen

Valley to be designed accordingly.

As per the storage system, it is reasonable to assume that it should be able to store the equivalent of one week of the hydrogen refueling station demand, to be able to exploit the PV electricity supply during the central hours of the day when no refueling is programmed, as well as to provide low-cost hydrogen in the case of low PV and wind production.

The table below summarizes the chosen storage sizes for the three considered cases.

Fleet	**Storage Size**	**Unit**
5 FC Bus Fleet	8	MWh
10 FC Bus Fleet	16	MWh
15 FC Bus Fleet	24	MWh

Table 6.2: Storage Sizes

Some considerations can be made in advance for the *Low Demand Scenario*, especially in terms of electrolyser utilization. The derived hydrogen demand profile is reaching peaks of 0.6MW, which is not comparable with the 4MW electrolyser installed capacity and will certainly entail a longer payback time for the entire project.

Another critical aspect to be considered is the fluctuations in the hydrogen demand, which are incompatible with the optimal operation of most electrolysers. Hydrogen production is optimized when the electrolyser is able to operate as base load, with a minimum production occurring at all times.

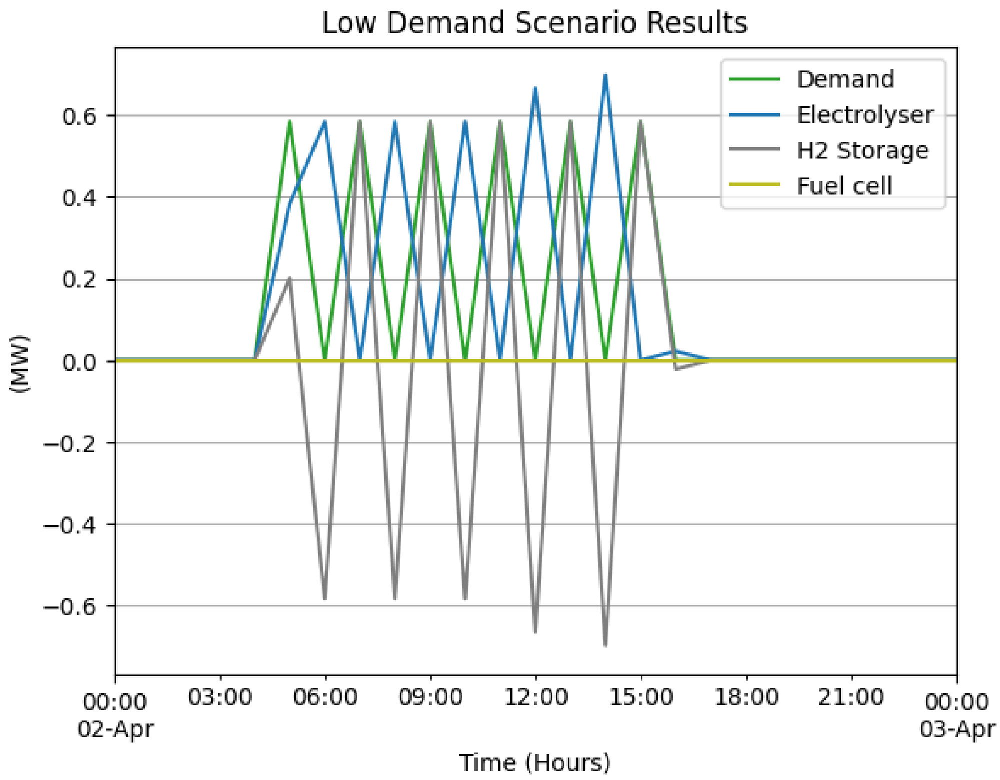

Figure 6.2. Scenario Results Low Demand Scenario

Results reported in Figure 6.2 represent the case involving the 15 FC bus fleet, as the outcome of the others is a scaled version and very similar. The plot shows results from a randomly chosen day in the year, where both electrolyser and storage are useful to supply the load, although neither of them reaches a considerable exploitation of their capacity.

The fuel cell results to be never operating, as the efficiency of the whole process is too low for the optimization process to include it.

It is clear that in this situation the electrolyser is oversized and underexploited, as its operation profile follows the load, causing ramps and long off times, which are not the preferable mode of operation for electrolyser technologies.

6.2 Intermediate Demand Scenario

The *Intermediate Demand Scenario* represents the expansion of the Hydrogen Valley supply to different sectors. As previously mentioned, the Crete-Aegean Hydrogen Valley is situated in a strategic location as the large port of Atherinolakkos offers the possibility to introduce hydrogen in the maritime sector.

Crete is strategically located in the heart of the Mediterranean Sea, making it a pivotal point for numerous commercial maritime routes. This central positioning not only enhances the island's accessibility for trade and transportation but also places it at the crossroads of important shipping lanes that connect Europe, Asia, and Africa.

Nevertheless, to simplify the introduction of hdyrogen in this sector, it is assumed that a fleet of FC ships for touristic routes is introduced in the system as final user.

To fully explore this option, it is necessary to make some assumptions about what could be the evolution of the hydrogen demand in the maritime sector. As seen in Chapter 2, FC ships are already under development, as some examples are currently deployed around the world. Literature references [35] state that maritime fuel cells require higher power outputs, often exceeding 100kW. Nevertheless, such high demand cannot be satisfied with the current constraints imposed on grid utilization. The grid is modeled as a generator with maximum power output of 50kW, but in these conditions it is not possible to optimize the system, therefore an initial assumption of smaller FC capacity is made, reaching 50kW of capacity. Alternatively it is possible to relax the imposition of maximum nominal power on the generator representing the grid, allwing to consider a more average size for the ship FC (100kW) whilst guaranteeing demand satisfaction. Results of both these options will be analyzed in the following chapter. Normally touristic ship FC are operating around 8 hours per day if considering routes frequented only during the day, which allows an approximative calculation of the single FC ship daily demand, assuming

50% efficiency of the FC.

$$Demand_{ship} = \frac{50kW * 8h}{0.5 * 33.33kWh/kg} = 24kg/day$$

It is assumed that an initial fleet of 12 ships is expected daily for refueling at the port.

In order to construct the demand profile, the total daily demand was distributed throughout the day according to a Gaussian function. This distribution was generated by calculating values based on a Gaussian curve, ensuring that they reflected a natural variation in hours while maintaining the overall total. The resulting values peaked in the middle of the day, gradually decreasing towards the early morning and late evening, thus capturing the typical pattern of activity throughout the day.

The total daily demand includes the FC bus fleet and the touristic ship refueling, with an extra margin to account for unforeseen circumstances.

The bell-shaped curve is chosen to better fit the PV production availability while also avoiding the complete shutdown of the electrolyser.

To ensure the final users are supplied at all times, including the night hours when demand remains consistent and combined with low PV production, for this scenario the other green electricity source, the wind plant, is increased in capacity to be equivalent to the first one. Installed wind capacity is therefore 4MW.

As expected, the electrolyser operation profile follows RES availability, peaking in the central hours of the day when PV production is very high, even reaching maximum capacity, and quickly lowering towards the night hours, where the wind plant contributes.

Increasing demand causes the results profile to present a larger variability day to day; results shown in Figure 6.4 are representative of a randomly chosen week. It is possible to notice the influence of the PV production in the electrolyser operation profile, which increases during the central hours of the day, although it is not quite

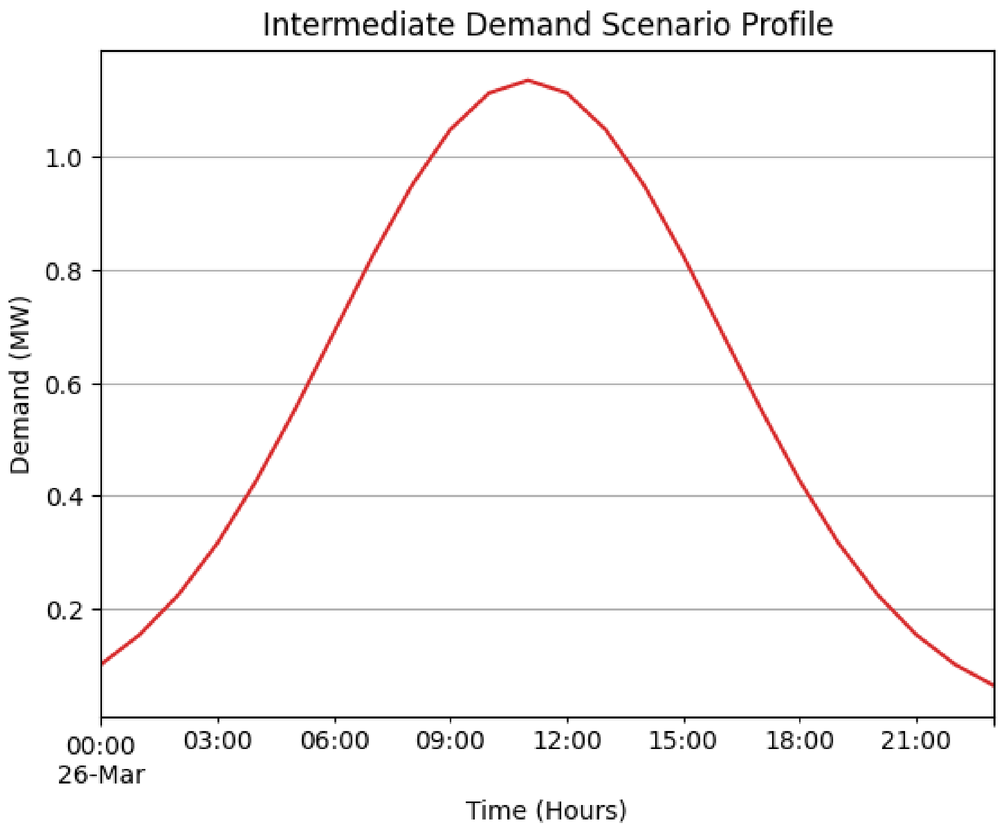

Figure 6.3. Intermediate Demand Profile

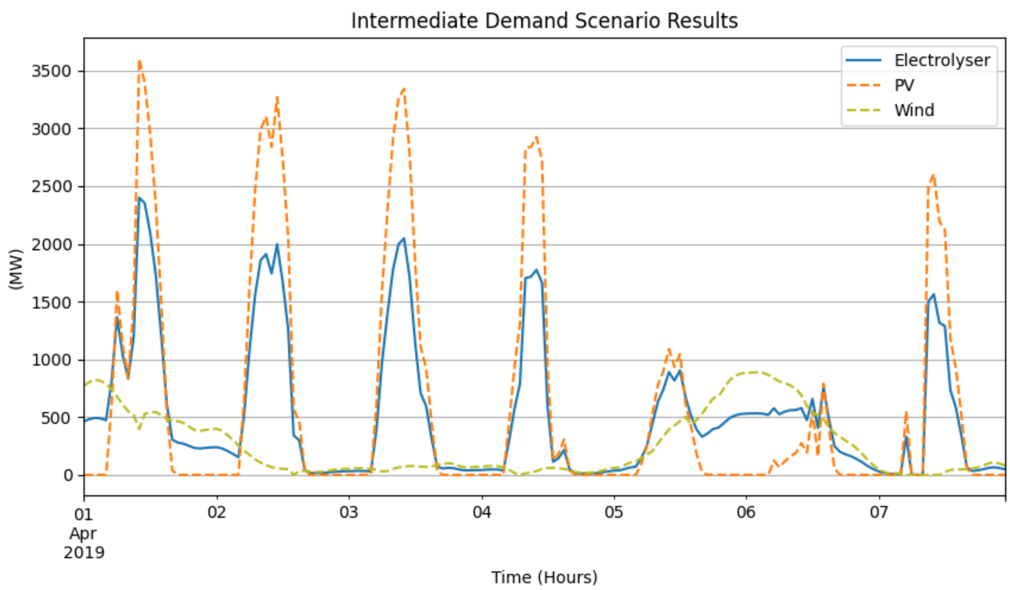

Figure 6.4. RES Generation Intermediate Demand Scenario

enough to satisfy the load, therefore a contribution of the storage is required. In the first and last hours of the day, the storage system plays a fundamental role in supplying the load, when the electrolyser functioning becomes less convenient due to lower RES production.

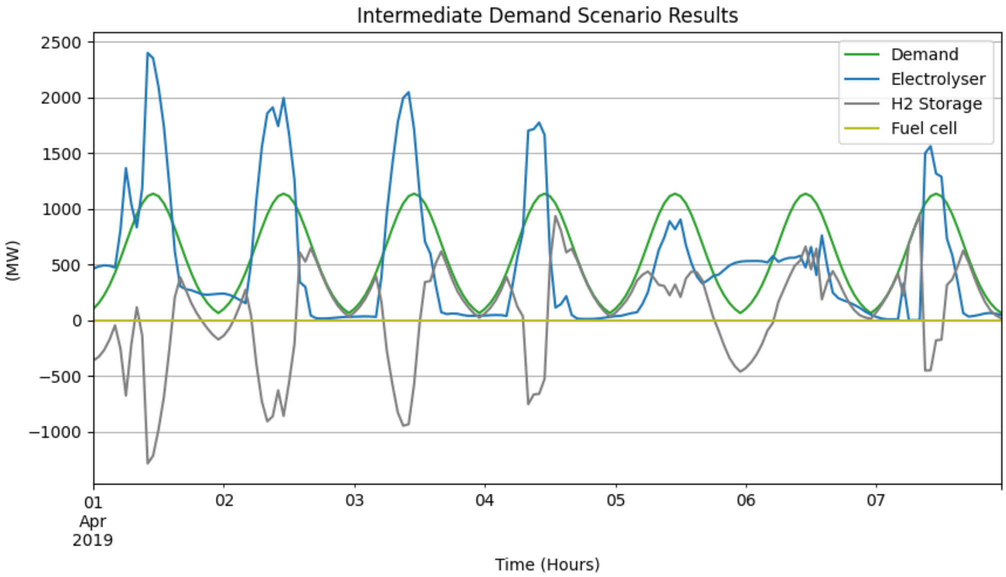

Figure 6.5. Scenario Results Intermediate Demand Scenario

It is also possible to notice how the electrolyser seems to be oversized if one only considers the first few days of the week under study. Extra hydrogen production is exploited for storage charging.

Once again the fuel cell remains unprofitable throughout the whole simulation.

6.3 High Demand Scenario

The *High Demand Scenario* is developed through some assumptions regarding the future development of the European energy systems in terms of hydrogen integration, as the Crete-Aegean Hydrogen Valley project is expected to be supplying hydrogen to industries located in mainland Greece and Europe.

This scenario is yet to be representative of a near future situation and therefore explored in order to give a more complete overview of the potential of hydrogen valleys.

For this scenario, it assumed that each day a 500kg tube trailer will be filled and shipped towards mainland Greece, where it will contribute to the supply of the industrial sectors of Greece. The size is chosen based on common state-of-art hydrogen tube trailers as indicated in literature. [56]

As previously highlighted, maintaining a stable, consistent load for the electrolyser is highly preferable to minimize operational costs associated with fluctuating power demands. A flatter load profile helps avoid the increased wear and tear caused by frequent ramps—sharp increases or decreases in power demand—which can accelerate equipment degradation and necessitate more frequent maintenance. Additionally, a steady load reduces the likelihood of efficiency losses that can arise when the electrolyser is forced to ramp up or down, allowing it to operate closer to its optimal capacity range.

By avoiding these load fluctuations, the system benefits not only in terms of cost savings on maintenance and reduced downtime but also in terms of overall energy efficiency. Minimizing these operational ramps can also lead to improved grid stability and predictability in power consumption, which may translate into better integration with renewable sources and further cost reductions. In short, sustaining a flat load for the electrolyser aligns both economic and operational priorities, making it a key objective in optimizing system performance and resource use over the long term.

To construct the demand profile, the same approach of *Intermediate Demand Scenario* is used, distributing the total daily load according to a Gaussian function peaking at 12 pm. Once again, a complete shutdown of the electrolyser is avoided for technological and cost-related reasons.

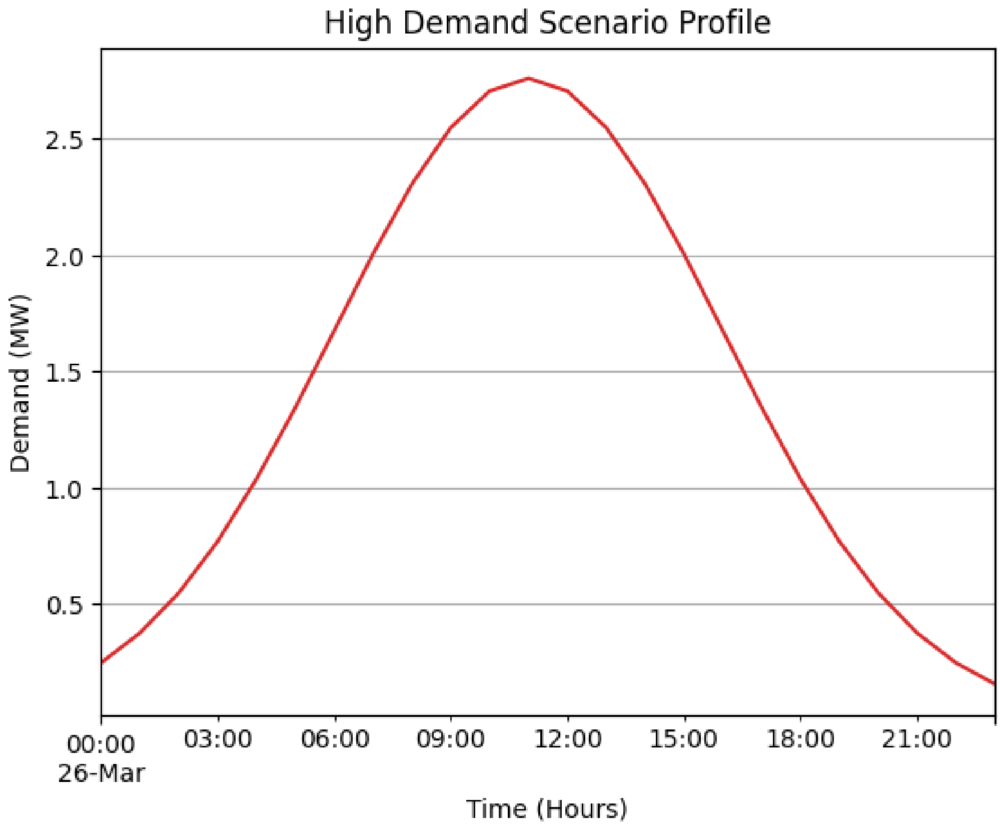

Figure 6.6. High Demand Profile

As demand increases the provided structure for the hydrogen valley must be adapted, increasing the capacity of components to handle such a demand profile. There are a few options to work on, in order to allow a proper functioning of the hydrogen valley. Production capacity and user supply are affected by many factors, including the green electricity supply, the electrolyser capacity and the storage availability.

To enable the simulation, each component has been adjusted in both design and capacity to achieve a configuration that ensures reliable supply to all end users. These modifications were essential to establish design conditions that support optimal performance and meet the demands of the system effectively.

As the primary objective of the Crete-Aegean hydrogen valley is to produce green hydrogen, the first investigation regards green electricity sources. Having increased the demand profile to up to 3MW, it is fundamental to ensure stable supply can be available at all times. The currently deployed 4MW PV plant may not be sufficient to cover the demand curve, although missing capacity is likely to impact the night hours, when in the absence of PV production. It is then necessary to act on the wind plant, doubling its size to help cover the nighttime demand, therefore reaching 8MW of installed capacity.

The *High Demand Scenario* is considered to be a stress test, although not really representative of the reality as the proposed demand profile results in higher annual production than what is actually expected. This study aims to define what improvements and changes should be applied to the valley to satisfy a higher hydrogen demand, in all likelihood not in the near future.

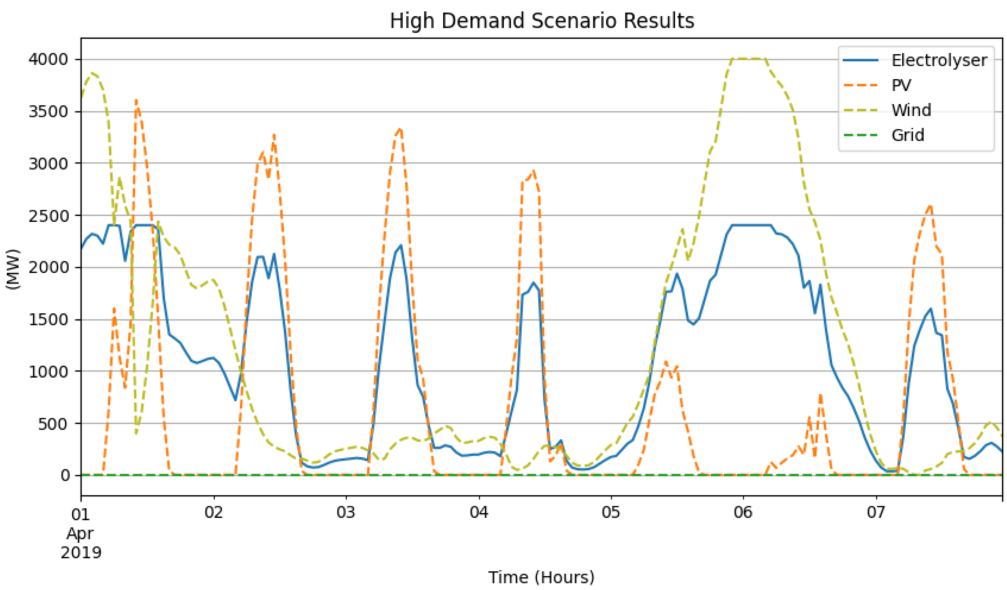

Figure 6.7. RES Generation High Demand Scenario

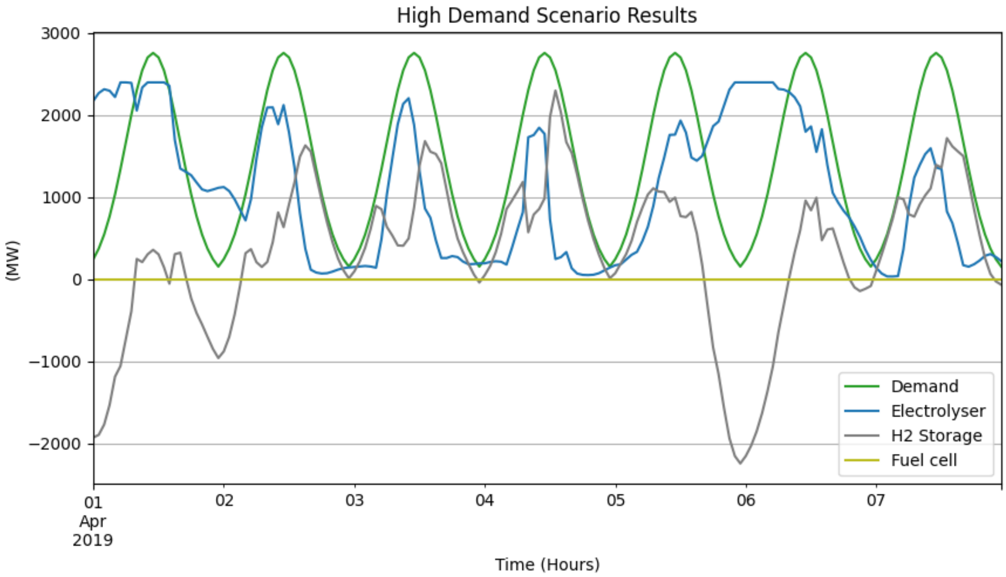

Figure 6.8. Scenario Results High Demand Scenario

Analyzing the results, the contribution of the PV plant is evident and given by the bell-shaped electrolyser profile in the morning hours. In this section, the load is fully supplied and extra hydrogen production is partially recovered in the storage system. As expected, storage plays a key role after 6 pm, when RES availability lowers, but demand remains considerable. Once again, the fuel cell is not profitable enough to be employed.

Chapter 7

Results and Scenario Comparison

As all scenarios have been created and briefly described in the previous chapter, simulation results are available for a deeper analysis of the hydrogen valley functioning and the integration of whole the components from a system perspective.

The results analysis will focus on some fundamental themes, starting with RES integration in the system: both PV and Wind plants are contributing to the electrolyser operation, although they also represent a cost for the system. It is important to understand whether they are properly sized to avoid extra costs and oversized components, as well as to avoid designing a system for green hydrogen production with insufficient RES availability.

Moving to the midstream section in the hydrogen valley, electrolyser and storage will be studied to evaluate their performance and, once again, their integration with the other components of the valley.

7.1 RES Utilisation

The input green electricity sources, PV and wind plants, have been sized based on the electrolyser capacity and increased according to the increasing demand profile. As they represent a cost for the system it is important to know their utilisation to evaluate whether they have been properly designed.

The utilisation has been calculated for all three scenarios in each snapshot in relation to the given production profile, according to the following formula.

$$U = \frac{ActualProduction}{ExpectedProduction}$$

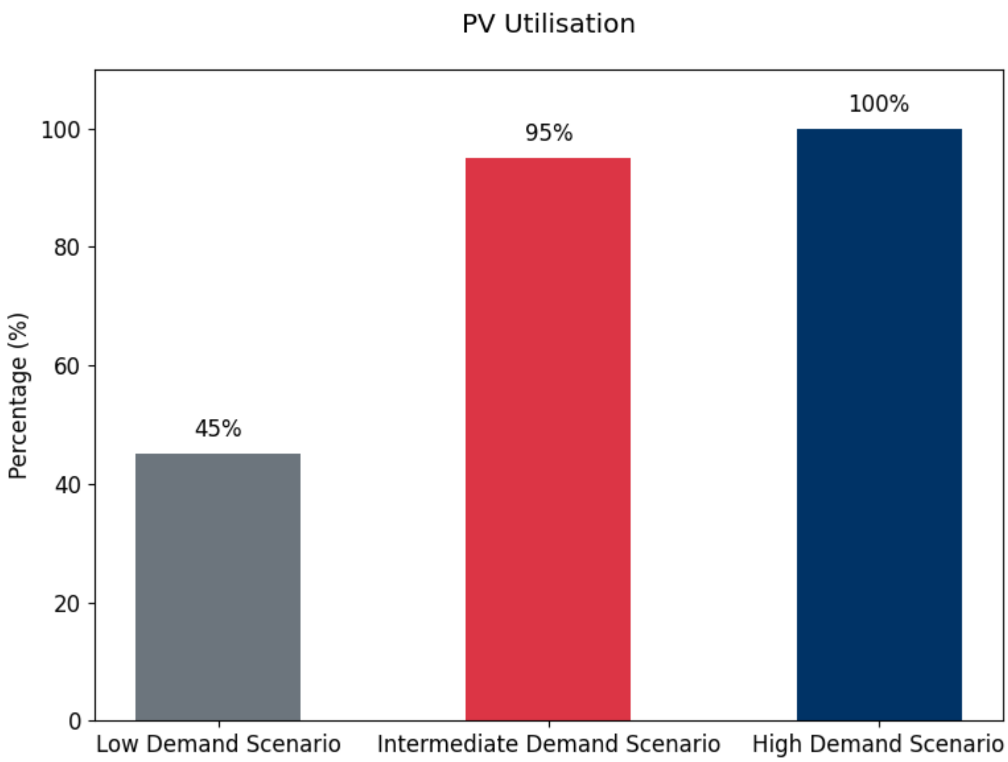

Figure 7.1. PV Utilisation

Where the *Expected Production* is the input profile of production which has been retrieved on *PVGIS* and *Renewables.ninjia* respectively; the *Actual Produciton* is the optimised production profile as determined by the PyPSA optimisation process.

The average values give information about the rationale behind the optimisation process, indicating how much of the available green electricity is necessary to optimally operate the hydrogen valley.

In Figure 7.1, the results indicate that, excluding the *Low Demand Scenario*, the available PV production has been almost completely supplied to the the electrolyser. In the *High Demand Scenario*, 100% utilisation may indicate that the PV plant has been undersized and that the system is overall stressed.

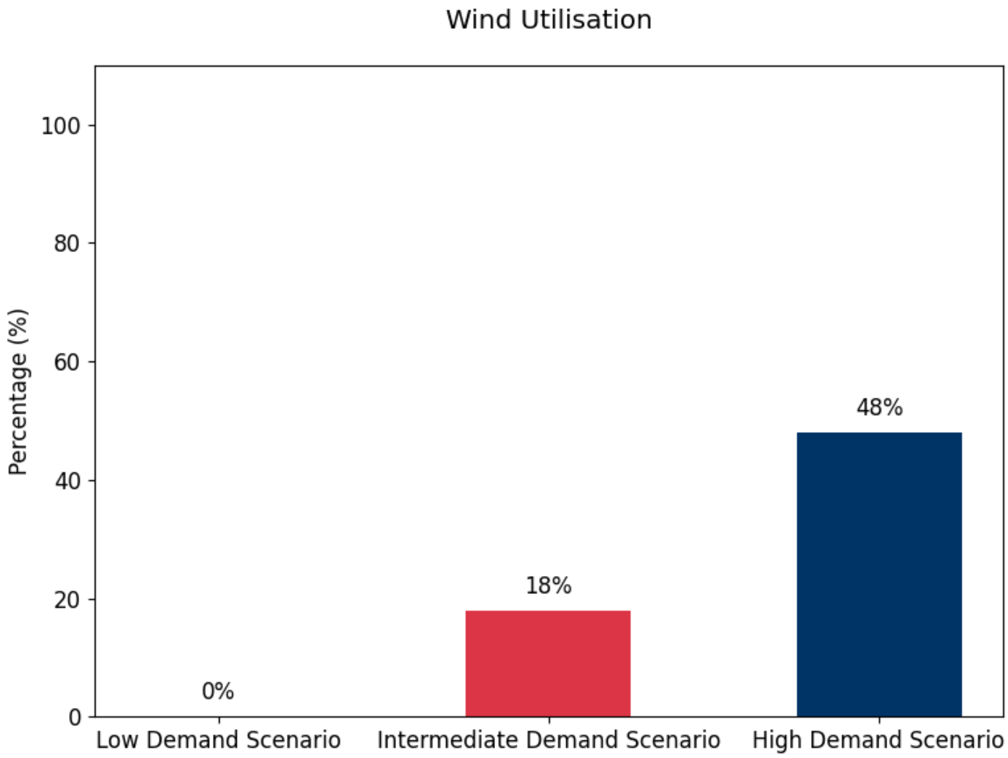

Figure 7.2. Wind Utilisation

In Figure 7.2, the utilisation values for the wind plant indicate that the wind plant is mostly oversized, although their contribution is quite relevant when in the absence of PV production, therefore reducing its size would imply a higher contribution by the grid.

7.2 Grid Utilisation

As per the RES plants, the same analysis can be conducted for the grid input electricity, although in this case, it is more relevant to understand the contribution of the grid input to the electrolyser operation. To obtain these values, the electricity consumed by the electrolyser is considered, instead of the actual operation profile which takes into account the efficiency.

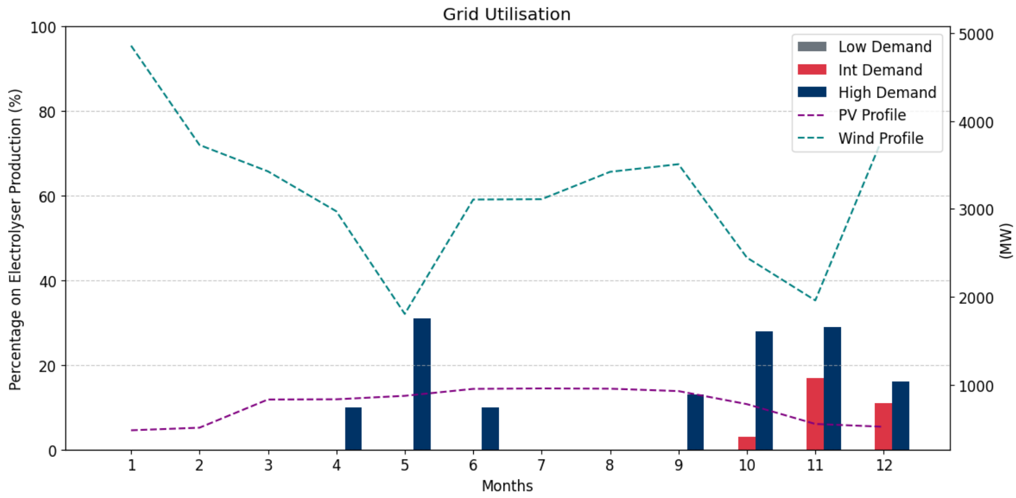

Figure 7.3. Grid Utilisation

Figure 7.3 shows some interesting results, where the grid contribution appears only in the *High Demand Scenario*, where the system is more stressed, and limited to some months throughout the year.

The reason behind the unusual profile of grid utilisation is quite evident when comparing this trend with the production profiles of wind and PV plants. In Figure 7.3 the production profile relative to the *High Demand Scenario* is reported and shows how the wind profile is the main contributor in this scenario and naturally presents some minimums around May and November.

Overall grid utilisation remains contained in all scenarios and would require oversized RES plants to further decrease.

As mentioned in the previous chapter, the demand profile for the *Intermediate*

Demand Scenario is built on the assumption of a 12 FC ship fleet with onboard hydrogen tanks to be refueled. A sensitivity study is performed on this scenario in order to account for the condition in which the onboard FC capacity is fixed at the state-of-art average capacity of 100kW, which would require higher grid utilization.

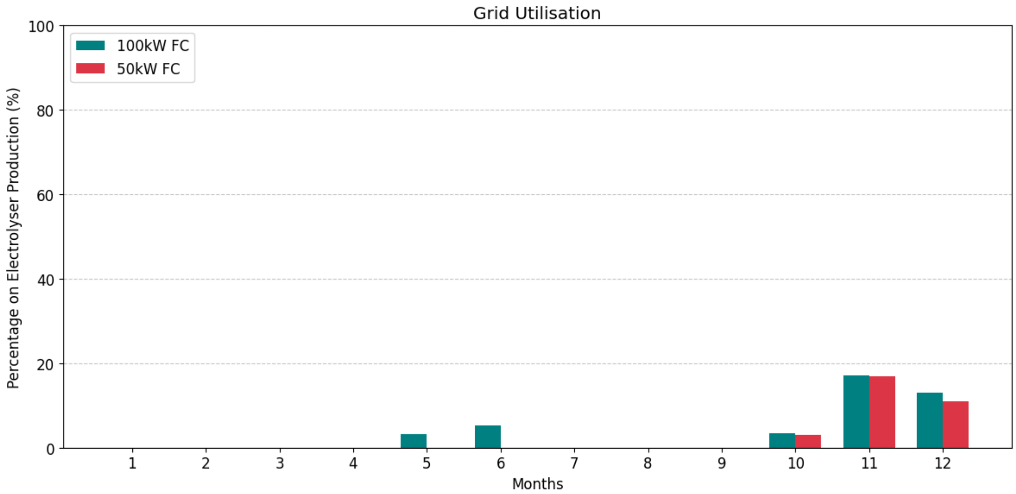

Figure 7.4. Grid Utilisation

The figure above confirms the higher need of grid contribution to the electrolyser input in the case of higher demand, as expected. It is interesting to notice how grid utilization remains limited to a few month in the year and to low percentages, indicating that higher installed capacity of RES systems would cause an oversizing issue on this front.

7.3 Electrolyser Utilisation

Figure 7.4 shows the load factor for the electrolyser, which increases with increasing demand, but remains quite low in absolute terms, reaching a maximum of 35% in the *High Demand Scenario*.

The issue regarding electrolysers low load factors is very well known in the scientific community and strictly related to the input source variability. The production profile of VP and wind plants are in principle incompatible with the optimal electrolyser functioning which is baseload and almost constant in time.

Another issue contributing to the low electrolyser load factor is the demand profile itself, which is built to resemble the PV profile, fluctuating in time with peaks in the central hours of the day.

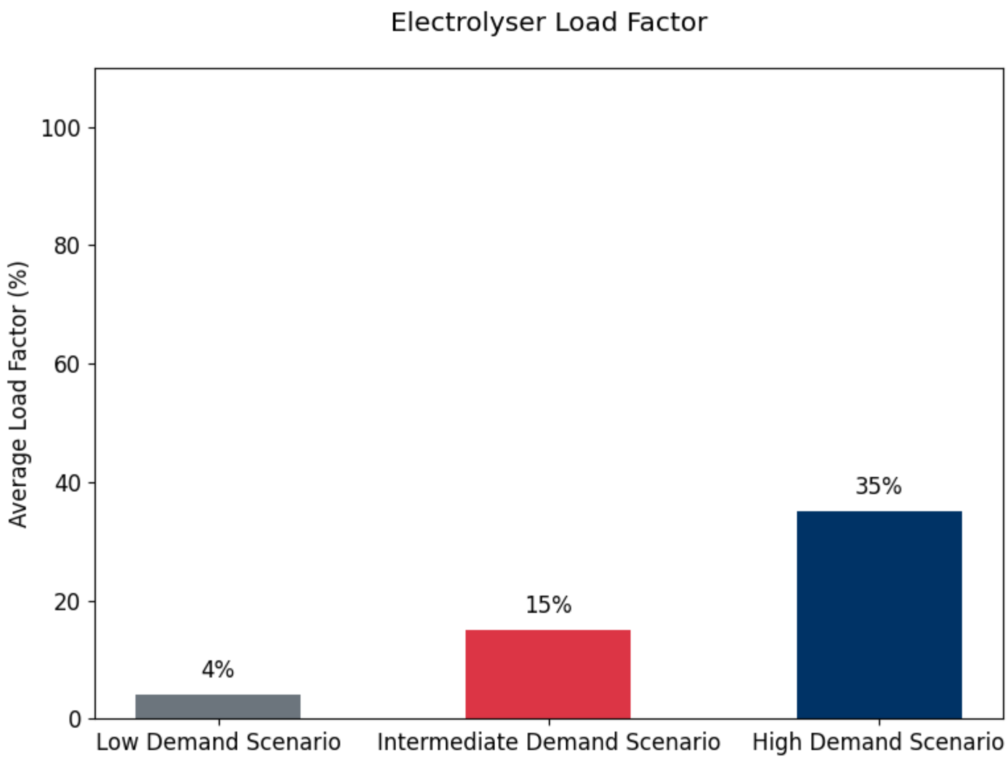

Figure 7.5. Electrolyser Utilisation

7.4 Storage System Analysis

Sizing and operation strategies for the storage are quite complicated matters and often result in bottlenecks for the system optimization.

In all scenarios, the storage system is optimized in its utilization by the model itself, such that the only input data regards the minimum and maximum state of charge. All three scenarios are developed with an intended storage capacity to be installed, which is determined by the optimization of the whole system. PyPSA library offers the possibility of leaving undefined storage capacity, allowing for the system to store the optimal amount of energy in each snapshot of the simulation.

After the first round of simulations, the storage capacity was fixed to the value corresponding to approximately one week of hydrogen demand. In this section said storage systems will be further analysed in their performance to evaluate whether their design parameters allow proper integration of the storage within the hydrogen valley.

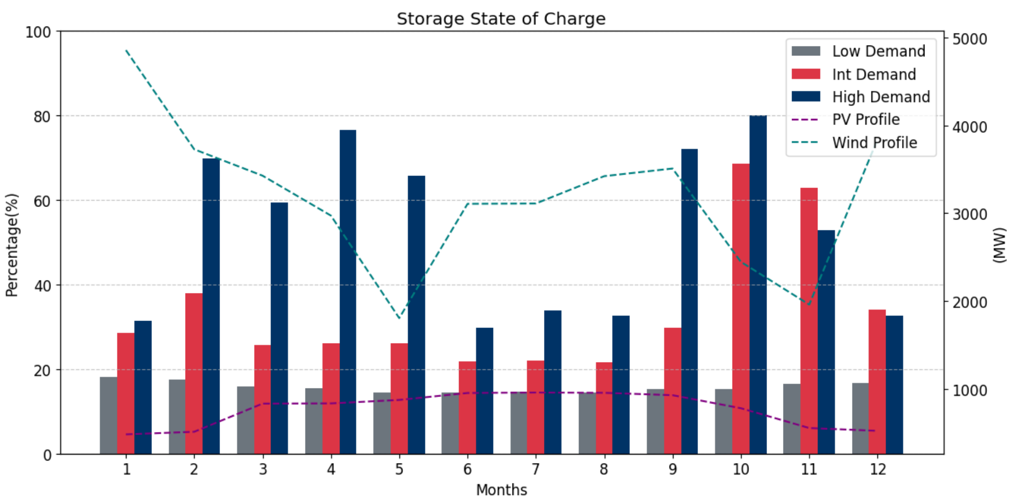

Figure 7.6. Storage State of Charge

In Figure 7.5 it is interesting to notice how the storage SoC is higher when there is lower RES availability. As demand is the same throughout the year, fluctuations in wind availability directly affect the SoC. The increase in the State of Charge (SoC) during months with lower wind input can be attributed to the system's ability to draw effectively from the grid, ensuring that hydrogen production remains steady and demand is met without significantly depleting stored hydrogen. Additionally, during these months, the storage system plays a crucial role by contributing more to the supply of hydrogen to users, compensating for the reduced generation from renewable energy sources. This dynamic highlights the integrated role of the grid and the storage system in stabilizing production, enhancing supply reliability, and maintaining efficiency in the overall hydrogen supply system.

A final consideration on demand supply can be elaborated by observing the following, where the different contributions of the electrolyser and storage to the load supply are indicated.

The storage behaves as a buffer, allowing it to perfectly manage fluctuations in electricity production. When RES energy is insufficient, stored hydrogen can be discharged to meet the constant demand for hydrogen, ensuring reliable supply.

Overall the analysis on storage shows that in lower RES production hours the operational strategy shifts towards a more frequent use of the storage system, allowing to reduce the over-reliance on grid electricity.

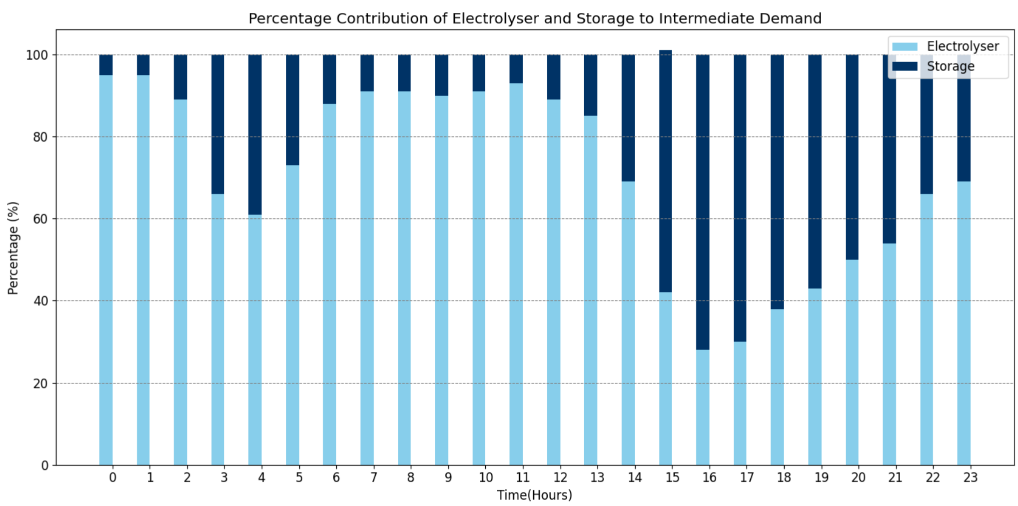

Figure 7.7. Load Supply Intermediate Demand Scenario

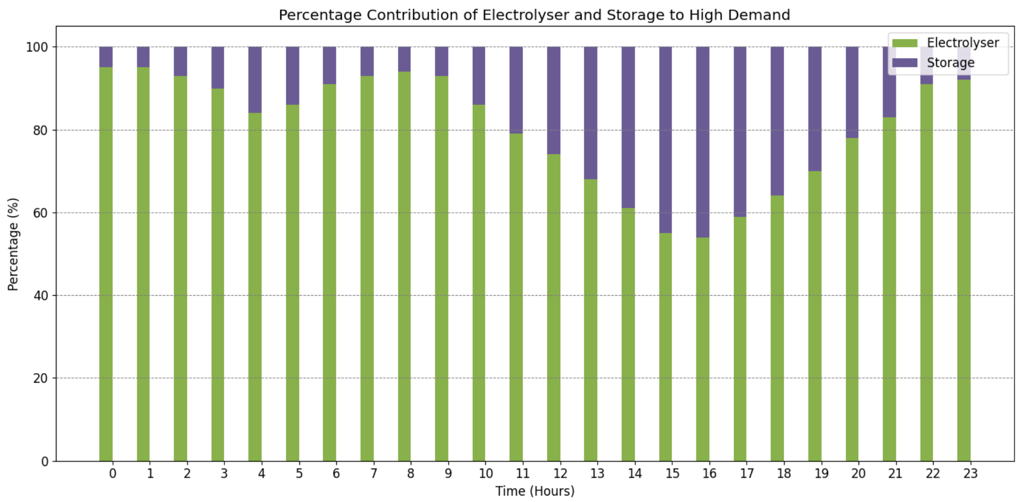

Figure 7.8. Load Supply High Demand Scenario

Chapter 8

Conclusions

This study focuses on the analysis of operational scenarios in the Crete-Aegean Hydrogen Valley, where renewable electricity sources are employed for the production of hydrogen through the electrolysis process with a 4MW electrolyser. The plant will be installed and operative on the island of Crete, a strategic location in the Mediterranean Sea, intersecting the future expansions of gas and electricity networks connecting mainland Greece and the rest of Europe with the eastern cost of the Mediterranean Sea and North Africa.

The plant will encompass the main steps of the hydrogen supply chain, from production to storage and delivery to final users. A compression phase follows the electrolyser and leads green hydrogen to a storage system that afterwards serves the hydrogen users. As the Valley becomes operative, an evolution of the hydrogen demand is expected. The first sector to be supplied will be transport - as a fleet of hydrogen fed buses will be operative for touristic reasons on the island of Crete - followed by an expansion into the maritime and industrial sectors. Increasing complexity will be inevitable once adding the export of hydrogen to mainland Greece and therefore will require time and adaptation.

Three operational scenarios are created and analyzed based on evolving demand for the Hydrogen Valley starting with the *Low Demand Scenario* where the FC bus fleet is increased from 5 to 20, each refueling a 40kg onboard hydrogen tank once a day. The *Intermediate Demand Scenario*, in addition, considers the diffusion of hydrogen in the maritime sector, assuming a 12 FC ship fleet refueling at the port. In this scenario, the increasing demand is distributed throughout the day in order to maximize hydrogen production coupling with PV production, which peaks in the central hours of the day. With this strategy, the electrolyser is avoiding complete shutdown whilst aligning with the electricity production profile. Night operation for hydrogen supply to the user requires additional capacity in the wind plant. Finally, the *High Demand Scenario* is built in the future integration of produced hydrogen in the industrial sector in mainland Greece and Europe. Exporting hydrogen from the island of Crete will be possible through tube trailers, which commonly have a capacity of 500kg. It is assumed that each day the load associated with the tube trailer for export will be added to the FC bus fleet and FC ship fleet refueling. Wind plant capacity is increased to address the demand increase especially in the night hours.

Analyzing the results of the model simulations for all three demand scenarios, some common conclusions can be drawn. In terms of end user supply, a key role is played by the PV production in the central hours of the day, whereas during the night hours a lower but still consistent contribution of the wind plant is noticed. In the latter situation, the hydrogen storage system becomes essential, switching to discharge to compensate the lower RES production and consequent lower electrolyser load. The storage works in charging mode whenever high RES production occurs in correspondence of low demand. The system is able to function with minimal grid utilization, reaching peaks of around 30% only in the *High Demand Scenario* and during months of lower wind electricity production.

Across all scenarios, the fuel cell is not operational, indicating the unprofitability of converting hydrogen back into electricity. It is significant to further advance studies on the model regarding the deployment of the fuel cell. In order to optimize its utilization for grid balancing services, it is necessary to better associate these services with proper remunerations to fully understand the fuel cell profitability and role in the Hydrogen Valley.

Electrolyser utilisation remains low in all three scenarios, reaching a maximum of 35% in the *High Demand Scenario*. While this represents a relatively low value in absolute terms, it is quite common and expected to have such results as electrolysis is mostly associated with green hydrogen production and renewable energy sources. The latter impose high variability, forcing fluctuations in the electrolyser operation. This situation is exacerbated by the demand profile itself.

The storage system operation is coupled with the RES availability, such that low PV or wind production months are associated with high average SoC for the storage. As the storage maintains higher levels of charge, the system is able to supply the load with lower strain on components whilst ensuring reliability and minimizing grid utilization.

The Hydrogen Valley model is a preliminary step towards refined representations of all its components and despite its novelty it is able to produce results on optimal components operations as explained above. Studying various possibilities in terms of demand for the Hydrogen Valley allows to understand the dynamics of interactions among components in the Valley and evaluate requirements in terms of components design.

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