

Article

Optimal Green Hydrogen Production and Transportation: Africa to Europe

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Abstract

This paper presents an optimization framework for green hydrogen (GH) production, which integrates the operation of subsystems consisting of photovoltaic generation, reverse-osmosis desalination, proton exchange membrane electrolysis, and battery energy storage for continuous operation under solar intermittency. A two-step Ordinal Optimization (OO) method is used to explore efficiently the large design search space and identify subsystem sizes that minimize the levelized cost of hydrogen (\$/kg), including production, storage, and transportation. First, the designs are evaluated using a simple but computationally efficient model based on a two-week simulation. The evaluated designs are then scaled to a yearly operation and ranked by increasing hydrogen costs. Second, the top-S designs are reevaluated using an accurate annual simulation model. OO theory predicts the number of top-S designs that need to be evaluated accurately to ensure that the optimum is included with a 95% alignment probability. This framework was applied to case studies for producing GH for local use in Tunis at a cost of \$2.945, and for shipping to Genoa, Italy, and to Hamburg, Germany, at costs of \$3.902 and \$6.382 per kg, respectively. The study leverages the potential of renewable energy (RE) production in Tunisia and its proximity to Europe.

Keywords: solar PV energy; Ordinal optimization; water electrolysis; hydrogen storage; green hydrogen shipping; cost of green hydrogen production

1. Introduction

The transition to clean energy is essential for improving quality of life and meeting environmental goals, but rising energy demand has intensified the reliance on fossil fuels, which has increased CO₂ and other harmful emissions. Green hydrogen, produced from low-carbon sources, offers a strong pathway to net-zero by 2050 [1]. Its production enhances renewable energy usage, helps in stabilizing the grid through cleaner energy, and reduces emissions in industry, transportation, and heating. Countries like Germany and the UK are already adopting it in sectors such as steelmaking and residential heating [1].

Hydrogen production is mostly fossil-based, with renewable electrolysis representing a small fraction. Green hydrogen (GH) can reduce CO₂ emissions and support renewable integration but remains costly, requiring production scaling and techno-economic optimization. Its role in decarbonizing hard-to-electrify sectors and enabling large-scale energy storage makes GH strategically important for low-carbon energy production systems [2]. Significant advances in hydrogen technologies are accelerating the clean energy transition; by 2050, hydrogen could supply nearly half of the EU's energy demand, requiring 3100 to



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6000 TWh annually [3]. Large projects like the NEOM Green Hydrogen Project—targeting 650 t/day by 2025—are expected to reduce CO₂ emissions by about 3 Mt per year and support the growth of a sustainable global hydrogen economy [3]. This trend is driven by the EU Renewable Energy Directive, and Green Deal policies, which promote zero-emission transport through CO₂ emission standards. However, challenges remain in harmonizing regulations governing hydrogen production and use [4]. Thus, the EU green hydrogen demand is expected to exceed domestic production, making imports essential, with Africa being a well-positioned key supplier due to its abundant renewable resources and proximity [5]. These trends highlight hydrogen's increasing strategic role in the energy transition for both Africa and Europe.

2. Literature Review

Researchers highlighted GH's vital role in decarbonizing power and industrial sectors. Goldmeier et al. [6] reported that GE is advancing hydrogen turbine technology to facilitate the transition toward zero-carbon energy, while Rubio et al. [7] emphasized that meeting climate goals requires a decarbonized economy. Using an optimization model, they estimate Spain's hydrogen demand for replacing conventional vehicles by 2030 and determine the electricity needed for GH production. They found that the estimated production costs using wind, solar PV, and hydropower are 81.37, 81.65, and 68.12 €/MWh, respectively. Based on the lower heating value (LHV) of hydrogen, these costs correspond to 3.15, 3.16 and 2.63 \$/kg. Kakoulaki et al. [1] found that most EU27 and UK regions could generate sufficient renewable electricity (290 TWh) to replace grey hydrogen with GH, which supports EU energy policy and emphasizes the need for further research on regional systems and hydrogen infrastructure.

Ayres et al. [8] highlighted that PEM electrolyzers efficiently produce hydrogen, but high electricity usage and costly components—such as iridium catalysts and thick membranes—keep costs well above the \$1/kg target, highlighting the need for technological improvements. Bratovčić and Tomašić [9] proposed to use new photocatalytic nanostructures and composite materials for water splitting by solar energy. However, significant challenges, like high recombination rate, poor visible light absorption, and the backward reaction, still hinder the development of this process toward being efficient and economically viable. Asaad and Karaki [10] evaluated a North African GH production plant using solar PV, seawater desalination, PEM electrolysis, and battery storage. Using Tunis weather data, they estimated a levelized cost of hydrogen (LCOH) at \$6.43/kg by 2030, falling to \$3.81/kg by 2050, suggesting improved competitiveness with carbon taxes. Alghool et al. [11] applied a mixed integer linear programming (MILP) model to optimize green hydrogen production in Qatar using PV/PV-T collectors and alternative water sources. PV-T dominated the hydrogen output, while treated sewage effluent was a preferred water source, with oxygen sales enhancing revenues. The LCOH was most sensitive to demand, PV-T costs, and oxygen prices, while carbon taxation had minimal design impact. Hussam et al. [12] evaluated green hydrogen production at the Shagaya Renewable Power Plant in Kuwait. Results show that a grid-connected PV–wind configuration is the most cost-effective, while stand-alone systems are economically less attractive, with system performance strongly influenced by PV costs. Rodrigues Vaz et al. [13] presented the design of a photovoltaic-based green hydrogen production plant in Ceará, Brazil, using the Systematic Layout Planning method to optimize equipment layout, production flow, and operational efficiency. The results confirm the technical feasibility and potential of large-scale green hydrogen production in Brazil with some limitations.

Hydrogen storage and transportation may be realized as either gas under very high pressure or in a liquified state. Rong et al. [14] compared hydrogen storage and transport

options, concluding that compressed hydrogen is best for short distances and small volumes, while liquid hydrogen and liquid organic hydrogen carriers (LOHCs) are preferable for long distances and large-volume transport. LOHCs are particularly efficient for daily demands above 20,000 kg, and pipelines are effective for short, high-volume routes under 100 km.

Storage-tank materials have been studied and thoroughly tested during filling and emptying. De Miguel et al. [15] demonstrated that Type IV hydrogen tanks experience higher temperature rise and stronger temperature stratification during use, while Type III tanks enable faster and safer filling due to the aluminum liner's quicker thermal response, which also improves gas temperature monitoring. Ye and Lu's [16] life-cycle analysis showed that Type IV hydrogen tanks have the lowest emissions and lowest cost (\$10.4/kg H₂), outperforming Type III and cryogenic tanks, and making them the most efficient and practical option for hydrogen transport. The geometry and the mass of different storage tanks and their thermal response were investigated by Klymyshyn et al. [17], who developed a tool to estimate the geometry, mass, and cost of Type III and IV hydrogen tanks with about $\pm 10\%$ accuracy, helping assess storage feasibility for mobile and stationary systems.

The shipping of GH and its transportation cost are presented by Alkhaledi et al. [18] through "Jamila", a 370 m liquefied hydrogen (LH) tanker with a 230,000 t displacement, carrying 20,000 t of LH and reaching 19 knots with a 50 MW gas turbine engine. Its low deadweight, draft, and high freeboard result from hydrogen's low density, giving it characteristics similar to LNG carriers. They report that a 280,000 m³ LH tanker offers strong long-term financial viability, achieving a 45.1% IRR at a hydrogen price of \$2/kg in 2040 [19]. Kassembe and Gang [20] showed that ship costs decrease with size as capital costs fall from \$7200 to \$3600 per DWT for 50,000 to 200,000 t vessels, and operating costs, excluding fuel, drop from \$30,000 to \$11,000 per DWT per year. However, as larger ships benefit from economies of scale, they are less suitable for short-distance routes.

Optimization is commonly applied in engineering design to size system components for minimum cost and yet feasible operation. Ordinal Optimization (OO) [21] is a very efficient metaheuristic technique that formulates the problem as a search in a large design space using simulation to identify the best design based on ranking or "order". Jabr and Pal [22] applied OO for distributed generator (DG) placement and sizing, achieving reliable results with lower computational effort than stochastic or other metaheuristic methods. Karaki et al. [23] used OO to optimize the sizes of subsystems in a fuel cell hybrid electric vehicle, showing significant benefits in hydrogen savings and in car performance. Both studies highlight OO's potential for solving complex energy problems efficiently. Dias et al. [24] applied genetic algorithms to optimize the Celza GH network, projecting 3.1 to 7.7 TWh demand by 2030 and about 1 Mt CO₂ reduction annually, while showing that the project could remain economically viable with only one-third of the planned 5.5 GW electrolysis capacity.

This paper presents a highly efficient framework to evaluate the sizes of the different subsystems involved in the production of green hydrogen (GH) in Africa and its transportation to Europe at minimum cost. Six subsystems are considered in this evaluation: a photovoltaic (PV) plant, a reverse-osmosis (RO) plant, a PEM water electrolyzer, battery energy storage, hydrogen compression pressure, and hydrogen storage for local use, or ships for transportation to Europe. Thus, the problem is formulated as a combinatorial problem defined by the combinations of subsystem sizes, and the solution is found using a search process that is based on Ordinal Optimization (OO). The OO method is based on two principles: firstly, "order" is robust against noise, and secondly, "goal softening" that seeks "good enough" solutions with a high probability of being optimal, instead of insisting on reaching the best one, can significantly ease the computational burden [21].

Thus, in the first step, the OO method examines the search space using a simple, but computationally efficient, operational simulation to evaluate all the different designs in the search space. Then “order” is used to rank the designs in a decreasing levelized cost of hydrogen (LCOH). However, due to the use of a simple model, noise is introduced in the ranking, and a second evaluation is needed to remove this noise. Furthermore, OO theory predicts the number of top-S designs that we need to reevaluate, using an accurate model, in order for the optimum design to be included with a high alignment probability. The simple model is based on a two-week operational simulation with annual scaling; the accurate model is based on simulating the top-S designs over a full year. The best among these “really good-enough” designs is selected as the design having a high probability of being the optimum. The merit of this approach is its ability to find “really good-enough” designs among many specified options very efficiently, using operational simulation only, which is enabled using an energy management system (EMS) to integrate the operation of the different subsystems under daily and seasonal solar radiation variations. The goal of the EMS is to operate the system within the specified subsystem sizes that define the constraints. A system that is overdesigned in terms of the battery storage, for example, has assets that are not contributing to hydrogen production and is likely to yield a relatively higher levelized cost of hydrogen (LCOH) in \$/kg and thus is less likely to be selected as a “really good-enough” solution than a system with properly sized battery storage. In a way, the best design is the one where the subsystems’ sizes are properly matched, which may only be tested through the operational simulation. It may be argued that any subsystem oversizing may yield a relatively higher LCOH. Following the operational simulation of each design, the annualized capital and operational costs are calculated and divided by the annual hydrogen production to deduce the levelized cost of hydrogen (LCOH) in \$/kg for the design being evaluated.

To appreciate the efficiency of the OO search process, consider that seven sizes for each of the six subsystems are defined; in this case, the search space has 117,649 ($= 7^6$) possible designs, which is not a very large space for combinatorial problems. When these designs are evaluated using an exhaustive search based on an accurate model, this would take 24,624 s or about 7 h. While such evaluation seems achievable, its utility is significantly compromised when designing a system, as originally the bounds of the search space are not well-defined initially and may need to be modified. If the optimum design is found to be at one of the bounds of the search space, then the bound in question needs to be relaxed, and the designs are to be reassessed. When designing the system, this reassessment may occur several times in some iterative way. A wait of 7 h by the designer, at every modification and reassessment, makes the use of such a tool rather impractical and burdensome. The two-step OO process would typically take 16.4 min for the above-described case. Thus, the waiting time for any reassessment falls well within normal expectation of finding a “really-good” design with a high probability of being the optimal design. The use of simulation to find the optimum design is in some respects similar to genetic algorithms (GAs); however, the OO approach is computationally much more efficient, and its solution is repeatable and tractable. When using GAs to find the optimum design of the above search space, with a population of 100 and running over 150 generations, it would require 15,000 evaluations, which would require about 52.3 min. This is higher than the time needed for the two-step OO process, which is about 16.4 min.

The novelty of this work is the application of an Ordinal Optimization (OO)-based framework to the integrated techno-economic optimization of a green hydrogen production and transportation system from North Africa to Europe. Unlike conventional optimization approaches that require evaluating every candidate design or rely on computationally intensive metaheuristic algorithms, the proposed two-stage approach combines a simpli-

fied screening model with a detailed annual simulation to efficiently optimize multiple interconnected subsystems, significantly reducing computational time while maintaining high solution quality.

The effectiveness and versatility of the developed tool are demonstrated through its use to carry out three case studies: (i) green hydrogen production and storage for local use, (ii) production and maritime transport from Tunis to Genoa, and (iii) production and transport from Tunis to Hamburg. The results confirm that the proposed OO-based methodology provides a practical, computationally efficient, and scalable decision-support tool for large-scale green hydrogen system design under realistic conditions.

3. Problem Formulation

A system overview of the green hydrogen (GH) production plant in North Africa (NA) is shown in Figure 1. GH is produced either for local storage or for shipment by sea to Europe. The PV plant generates electric power for a PEM electrolyzer to separate water into hydrogen and oxygen. A reverse-osmosis (RO) plant desalinates seawater to produce freshwater and feed it to the electrolyzer. The battery system supports continuous PEM hydrogen production, especially at night, albeit at a lower output rate, and is fully recharged by the solar panels in the day. GH may be used locally or transported to Europe via ships equipped with hydrogen Type IV containers, at very high pressures. Two shipping-by-sea case studies are conducted: the first has a sea distance of 856 km from Tunis to Genoa, Italy; the second has a sea distance of 4350 km from Tunis to Hamburg, Germany.

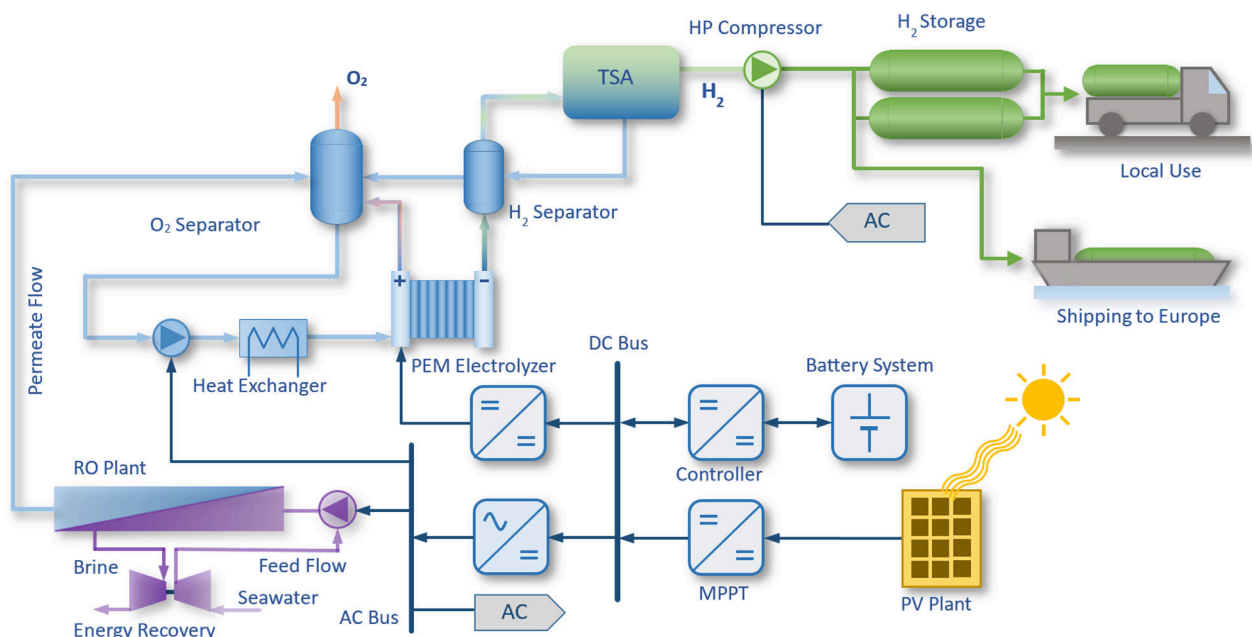


Figure 1. Green hydrogen production plant including two scenarios for its distribution. The yellow for the sun radiation and solar PV. Blue color for the permeate water (fresh water). Purple for feed water, sea water and the brine (non clean water). Green for green hydrogen. MPPT: Maximum power point tracker that continuously operate solar panels at voltages and currents that produce maximum available power. TSA: Temperature swing adsorption that act as a gas purification, captures the impurities at a lower temperature. HP compressor: High pressure compressor used for hydrogen storage at high pressures.

The objective is to determine the sizes of the plant subsystems that lead to a minimum hydrogen cost, in \$/kg, for production and delivery. The sizes are those of the PV plant, the battery system, the PEM plant, the RO plant, the hydrogen storage, and its pressure,

or the size and number of ships to transport GH to Europe. The different subsystem sizes define N designs over which the cost function φ (in \$/kg) is minimized:

$$\varphi = \min_{n=1,N} \left(\frac{IC(n) + O(n)}{D(n)} \right) \quad (1)$$

The annualized capital cost $IC(n)$, the annual operation and maintenance cost $O(n)$, and the annual hydrogen production $D(n)$ are evaluated for each design vector, [PV, PEM, RO, BT, PR, ST or SH], where the elements are the sizes of the subsystems. The cost $O(n)$ is evaluated using operational simulation guided by the rules of an energy management system, presented later, that keeps all operational constraints within the limits of the specified subsystem sizes.

4. Subsystem Modeling

4.1. PV Plant Model

The PV plant model determines the electricity generated by a set of panels under varying solar radiation and temperature conditions. First, the cell temperature (T_C) is calculated, which depends on ambient temperature (T_a) and solar irradiance (G), as follows: $T_C = C_T G + T_a$, where $C_T = (NOCT - 20)/800$ and $NOCT$ is the nominal operating cell temperature, which is determined under manufacturer test conditions at an ambient temperature of 20 °C; a typical value of $NOCT$ is 46 °C. At solar irradiance G , the short-circuit current I_{sc} and open-circuit voltage V_{oc} of the module are calculated as

$$I_{sc} = I_{sc0} \frac{G}{G_0} (1 + \beta_I (T_C - T_0)) \quad (2)$$

$$V_{oc} = V_{oc0} (1 + \beta_V (T_C - T_0)) + m V_T N_s \ln \left(\frac{G}{G_0} \right) \quad (3)$$

The quantities I_{sc0} and V_{oc0} are the short-circuit current and open-circuit voltage provided by the manufacturer at standard test conditions, i.e., at a solar irradiance $G_0 = 1000 \text{ W/m}^2$, and $T_C = 25 \text{ °C}$; β_I and β_V are the sensitivities of the short-circuit current and open-circuit voltage measured in per-unit/°C; m is the ideality factor of the PV junction that is estimated from test results at irradiances lower than 1000 W/m^2 to be about 1.8; V_T is the thermal voltage, which is equal to 0.026 V at 25 °C; and N_s is the number of series cells in one module. The average hourly power output, under field operating conditions, is determined by noting that the ratio of the voltage at maximum power (V_m) to the open-circuit voltage (V_{OC}) remains nearly constant as solar conditions change. Similarly, the ratio of the maximum-power current (I_m) to the short-circuit current (I_{sc}) also remains nearly constant. From this observation, the maximum power $P_m = V_m I_m$ at the current field conditions can be expressed as a function of the maximum power at STC, $P_{m0} = V_{m0} I_{m0}$, as follows:

$$P_m = P_{m0} \frac{(V_{oc} I_{sc})}{(V_{oc0} I_{sc0})} = V_{oc} I_{sc} F_{f0} \quad (4)$$

where F_{f0} is the fill factor of the PV module under STC conditions. This model is based on test data provided by manufacturers. The value given by Equation (4), for different panels, was compared to value of the power given by the manufacturers under NOCT test conditions, and the error was of the order of 1%. The annual PV energy is calculated by integrating hourly maximum-power values (P_m). Using the number of modules per design and the module characteristics, the total PV plant capacity is determined and used to estimate its investment and operational costs.

4.2. RO Plant Model

The RO plant is modeled based on the “Constant Water Recovery Rate” method outlined by Zein et al. [25]. This modeling approach keeps the RO recovery rate constant while permitting variations in feed pressure and flow rates to adapt to changes in available power. The fixed RO recovery rate operation, shown in Figure 2, offers better operational flexibility compared to the fixed feed pressure method recommended by RO membrane manufacturers.

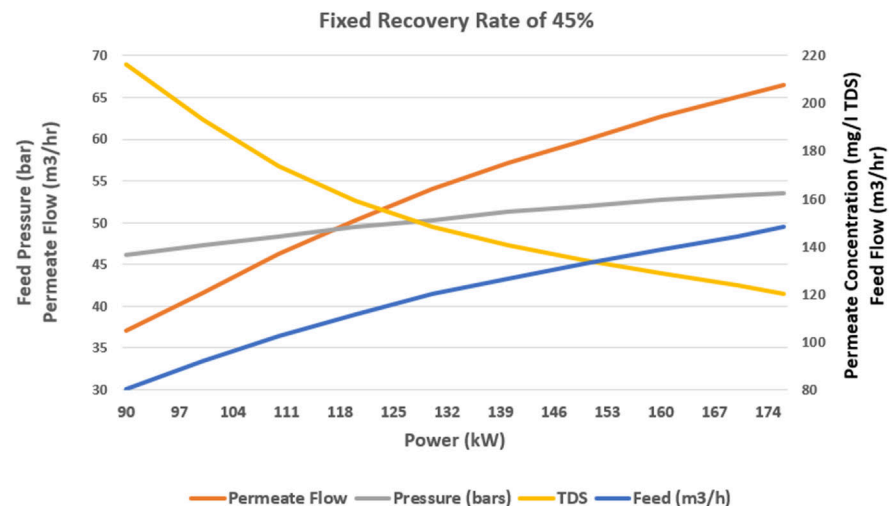


Figure 2. RO operation with 45% fixed recovery rate.

The high-pressure (HP) pump is controlled to supply the net RO feed flow at the required pressure, while the booster pump manages the energy recovery device (ERD) flow to recover the pressure in the concentrate stream.

4.3. PEM Plant Model

To determine the power required by the PEM system, a function is developed to account for the hourly hydrogen production rate, system efficiency, current density, and voltage per cell. The PEM electrolyzer’s cell voltage (V_{cell}) depends on three main voltage components: the ohmic voltage (V_{ohm}), representing internal losses, the activation voltage (V_{act}), required to trigger the reaction, and the Nernst potential (E_{cell}), which is the minimum voltage needed to split water molecules [26]:

$$V_{cell} = E_{cell} + V_{ohm} + V_{act} \quad (5)$$

The electrolyzer output voltage V_{ele} , of a stack of N_s series cells, is given by

$$V_{ele} = V_{cell} N_s \quad (6)$$

The total operating current (I_{ele}) of N_p parallel stacks each of N_s series cells is directly related to the hydrogen demand $\dot{m}_{H_2}$ (kg/s) as follows:

$$I_{ele} = \frac{2 F \dot{m}_{H_2} (1000) N_s N_p}{m_{wH_2} \eta_F} \quad (7)$$

The Faraday constant F is equal to 96,485 C/mol, $\dot{m}_{H_2}$ is the flow rate of hydrogen (kg/s), m_{wH_2} is the hydrogen molecular weight (g/mole), and η_F is the Faraday efficiency. The number of parallel PEM stacks in each design is specified, and the cost of investment can be determined, while the number of cells in series per stack is constant as determined

by the specified operating voltage of the PEM electrolyzer. The power required by the electrolyzer (P_{ele}) is given as

$$P_{ele} = (V_{ele} I_{ele}) (1 + \rho_{aux}) \quad (8)$$

where ρ_{aux} is the ratio of auxiliary to output power.

4.4. Battery Storage Model

Energy storage is provided by batteries that are charged during the day from the solar PV plant to continue hydrogen production at night, however at a lower rate. The storage size is defined by the number of parallel battery strings, and the simulation checks whether this configuration can provide reliable charging and discharging. Each string contains 500 series battery cells. The battery voltage (V_{bat}), and its resistance R_{bat} are given by

$$V_{bat} = V_{cell} N_s \quad (9)$$

$$R_{bat} = R_{cell} \frac{N_s}{N_p} \quad (10)$$

The state of charge (SOC) of the battery is monitored hourly to determine whether it requires charging when sufficient solar energy is available to keep its SOC below the maximum threshold. Additionally, the battery SOC should be evaluated to ensure that it exceeds the minimum level of 20% when it is required to supply power. The SOC at time t is calculated as follows:

$$SOC(t) = \frac{Q(t)}{E_{max}} = \frac{Q(t-1) - (P_{bat} + P_{loss})\Delta t}{E_{max}} \quad (11)$$

Here, P_{bat} represents the power output of the battery, which is positive when discharging, P_{loss} denotes the power loss of the battery, $Q(t)$ is the internal energy of the battery at time t , and E_{max} is the energy capacity of the battery. The power delivered by the battery is $P_{bat} = I_{bat} V_{bat}$, and so P_{loss} is given by

$$P_{loss} = I_{bat}^2 R_{bat} = \left(\frac{P_{bat}}{V_{bat}} \right)^2 R_{bat} = P_{bat}^2 \left(\frac{R_{bat}}{V_{bat}^2} \right) \quad (12)$$

4.5. Hydrogen Compression Model

A hydrogen production system also needs a compressor to prepare hydrogen for storage or transportation. The power (P_{com}) required by the compressor is given by [27]:

$$P_{com} = \dot{m}_{H_2} \frac{ZTR}{M_{H_2}\eta} \frac{N\gamma}{\gamma-1} \left(\left(\frac{P_{out}}{P_{in}} \right)^{\frac{\gamma-1}{N\gamma}} - 1 \right) \quad (13)$$

$P_{in} = 30$ bar is the inlet pressure of the compressor, which is fed from the electrolyzer, P_{out} is the outlet pressure of the compressor, which is the tank pressure calculated using the Redlich–Kwong real gas equation, Z is the hydrogen compressibility factor of 1.032, N is the number of compressor stages, assumed to be 2, T is the inlet temperature of the compressor, taken as 311 K, γ is the specific heat ratio equal to 1.4, M_{H_2} is the molecular weight of hydrogen in g/mol, η is the compressor efficiency, taken as 75%, and R is the universal gas constant. Hydrogen is compressed and stored in tanks, with a tank capacity determined by a specified number of production days for accumulation.

When transported to Europe, the hydrogen storage system essentially consists of large ships, with on-board storage with pressures ranging from 250 to 500 bar. The total power

consumption given by Equation (13) is integrated over time to calculate the annual energy of the compression process.

5. Scenarios of Green Hydrogen Production

Two scenarios of green hydrogen production are considered. The first is a local-use scenario where the GH is compressed and stored for domestic use in Tunis. For each design for this scenario, the subsystem specifications include the storage-tank pressure and size, and based on this the total capital, operation and maintenance costs are evaluated. The second scenario considers shipping to Europe, where GH is produced in Tunis and transported to Europe, and total costs are calculated based on ship capital cost, compression cost, and shipping expenses, considering different ship sizes and storage pressures that depend on the destination.

5.1. Green Hydrogen for Local Use

The approach uses the geometry, capacity, and material cost of Type IV pressure vessels. The storage-tank prototype is modeled after Provaris' H2Neo [28] compressed hydrogen carrier. The critical dimensions of the Type IV storage tank are the inner radius (R_{ins}) and inner length (L_{ins}); see Figure 3. The Type IV tank features a high-density polyethylene (HDPE) nonmetal liner and a composite carbon fiber (CCF) over-wrap [14]. The liner thickness t_{liner} is determined as follows:

$$t_{liner} = L_{ins} f \quad (14)$$

The factor $f = 0.04/250$ is the ratio of the liner thickness to the internal tank length [27]. In Figure 3, the blue part represents the thickness of the HDPE liner, and the grey part is the CCF thickness. The wall thickness (t_{wall}) of a Type IV storage tank depends on the internal pressure P and the inner radius (R_{ins}) and is given by [17]:

$$t_{wall} = \frac{F P R_{ins}}{\kappa_{fte} S_d} \quad (15)$$

F is a safety factor of 2.25; κ_{fte} is the fiber translation efficiency, which serves as a parameter representing the disparity between the theoretical and practically achievable strength of carbon fiber, with a value ranging from 75 to 85%; P is the maximum internal pressure of the tank (bar); and S_d is the pressure design strength of the carbon fiber laminate in the hoop direction, equal to 15,300 bar [17].

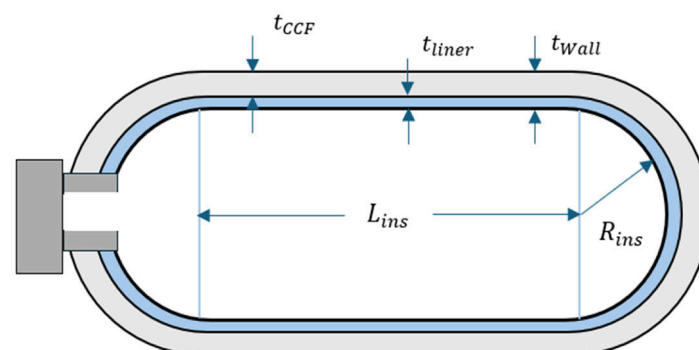


Figure 3. Type IV green hydrogen storage tank. The blue part represents the thickness of the HDPE liner, and the grey part is the CCF thickness.

The strength of the composite wall in the hoop direction is based on a laminate structure, with about two-thirds of the fibers oriented hoop-wise and one-third axially.

Carbon fiber vessels are fabricated with fiber tows in crossing helical patterns, which approximate the 1/3 axial and 2/3 hoop distributions. Based on the storage-tank geometry, its volume (V_{tank}) is given by

$$V_{tank} = \frac{4}{3} \pi (R_{ins})^3 + \pi (R_{ins})^2 L_{ins} \quad (16)$$

The weight of the materials for the CCF and HDPE liner is computed from their respective volumes as follows. The volume of the liner is estimated by

$$V_{liner} = \left[4\pi (R_{liner})^2 + 2\pi R_{liner} L_{ins} \right] t_{liner} \quad (17)$$

The liner radius and mass are, respectively, estimated by

$$R_{liner} = R_{ins} + \frac{t_{liner}}{2} \quad (18)$$

$$m_{liner} = V_{liner} \rho_{liner} \quad (19)$$

ρ_{liner} is the density of the liner, equal to 1370 kg/m³. The same process is applied for the CCF wrapping, whose thickness t_{CCF} is

$$t_{CCF} = t_{wall} - t_{liner} \quad (20)$$

t_{wall} is calculated using Equation (15), and the CCF mean radius (R_{CCF}) is determined by

$$R_{CCF} = R_{ins} + \frac{t_{CCF}}{2} \quad (21)$$

The volume of the CCF wrapping (V_{CCF}) and its mass m_{CCF} are, respectively, given by

$$V_{CCF} = \left[4\pi (R_{CCF})^2 + 2\pi R_{CCF} L_{ins} \right] t_{CCF} \quad (22)$$

$$m_{CCF} = V_{CCF} \rho_{CCF} \quad (23)$$

The density of the CCF wrapping with resin is ρ_{CCF} , equal to 1580 kg/m³ [29]. The mass of the storage tank is given by

$$m_{tank} = m_{liner} + m_{CCF} \quad (24)$$

The size of the GH storage for D_s days of production is determined as follows:

$$m_{H2} = CF(S_{PEM})(D_s) \quad (25)$$

m_{H2} is the size of the GH storage (kg), CF is a capacity factor of about 0.55, based on a one-year simulation, which represents the proportion of hydrogen actually produced and stored as compared to the electrolyzer's production capacity of S_{PEM} (kg/day), and D_s is the number of storage days. Consequently, the volume of GH storage (V_{H2}) is given by

$$V_{H2} = \frac{m_{H2}}{\rho_{H2}} \quad (26)$$

ρ_{H2} is the density of H_2 (kg/m³) at the nominal tank pressure. The number of storage tanks needed is then calculated as follows:

$$N_{tanks} = \frac{V_{H2}}{V_{tank}} \quad (27)$$

The total mass of the tanks (M_{tanks}) on a ship in kg is given by

$$M_{tanks} = N_{tanks} m_{tank} \quad (28)$$

The total cost of the storage system can then be determined as follows:

$$C_{tanks} = \frac{M_{tanks} c_{tank}}{0.9} \quad (29)$$

The cost of the tank c_{tank} in USD per kg of tank mass is based on a lookup table established using data by Karayel et al. [30], and the factor of 0.9 is to account for the balance of additional components needed for plant operation, according to Celestine [31].

5.2. Shipping Green Hydrogen from NA to Europe

This scenario examines transporting gaseous GH from Tunis to Genoa and from Tunis to Hamburg. The specialized vessels used in this study are based on the Jamila and Provaris H2Neo designs. The water displacement of a GH ship (M_{ship}), in t, is obtained using the following relation based on the evaluation of Jamila's fully loaded displacement tonnage [18]:

$$M_{ship} = L W D C_b \rho_{sw} \quad (30)$$

where L is the ship water-line length (m), W is the width of the ship (m), D is the draft of the ship at full load (m), C_b is the block coefficient at full load, and ρ_{sw} is the Mediterranean seawater density of about 1.025 t/m³.

The pressure-tank design begins by defining the base geometry—its internal and external shape—followed by calculating the wall structure needed to withstand internal pressure. Type IV cylinders are also chosen for transporting gaseous green hydrogen. A cylindrical tank with uniform wall thickness and hemispherical end caps is assumed, which is used to estimate the cost of the Type IV storage tank. The ship's hydrogen tank geometry is determined using standard storage-tank equations used in the local-use scenario, however with different dimensions. Since the ship carries two Type IV tanks, the total tank mass and the mass of hydrogen transported per ship are given, respectively, as follows:

$$M_{tanks} = 2m_{tank} \quad (31)$$

$$M_{H_2} = 2V_{tank} \rho_{H_2} \quad (32)$$

ρ_{H_2} is the density of hydrogen at the selected hydrogen pressure.

The cost of a Type IV hydrogen tank varies with its size and material mass. Using data by Karayel et al. [30], a lookup table is created to link tank mass (kg) to the specific tank cost (\$/kg) across pressures from 100 to 1000 bar, as shown in Figure 4. The cost of this ship's prototype storage tanks is as follows:

$$C_{tanks} = [c_{tank} M_{tanks}] / 0.9 \quad (33)$$

The factor of 0.9 accounts for the balance of plant cost [31], and c_{tank} is the unit cost of a tank (\$/kg).

The unit cost of a container ship is a critical factor to consider, which is expressed usually in USD per t, since the focus is on dry bulk shipping data analysis. Kassembe and Gang [20] established a relationship between the new building container ship and its deadweight tonnage. Based on this, the ship-hull capital cost (\$) can be calculated using the following equation.

$$C_{hull} = c_{hull} [M_{ship} \times 10^3 - (M_{tanks} + M_{H_2})] \quad (34)$$

where c_{hull} is the ship-hull unit cost (\$/kg), M_{ship} is the mass of the water displacement of the hydrogen ship (t), and $(M_{tanks} + M_{H_2})$ is the mass of the two hydrogen tanks when full. To sustain the greenness of hydrogen, the ships are assumed to be hydrogen-powered, which is a promising clean solution for maritime transport, producing minimum direct NO_x, SO_x, or particulate emissions [30]. The ship engine is driven by hydrogen using fuel cells and batteries, and its size is as follows:

$$E_S = \kappa_E M_{ship} \quad (35)$$

E_S is the engine size (MW), and $\kappa_E = 2.174 \times 10^{-4}$ (MW/t) is the ratio that relates the engine size (50 MW) of the Jamila LH2 tanker to its water displacement of 230,000 t [18].

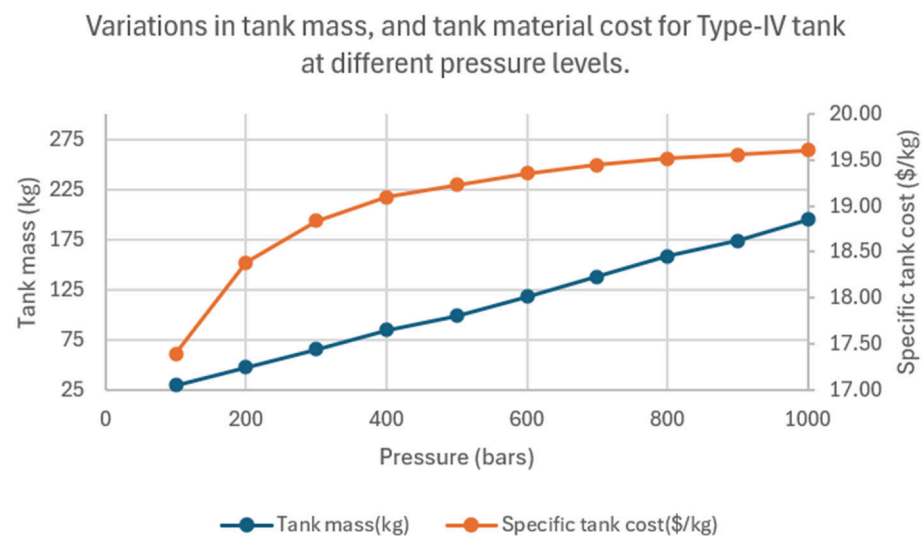


Figure 4. Variations in tank mass and tank material specific cost at different pressures.

6. Ordinal Optimization

When searching for an optimal solution in a large search space of designs, Ordinal Optimization (OO) is a method that makes use of two key principles [21]. First, noting that “order” is less sensitive to noise than “value”, and second, rather than aiming to find the “optimum” solution, looking for “good-enough” solutions with a high alignment probability of being the optimum, known as goal softening, significantly reduce the computational burden of solving the optimization problem. Figure 5 shows a flowchart of the OO process; first it uses a simple, efficient simulation to rank the search space designs by cost, identifying the really “good-enough” designs at the top of the list. A subset of these designs is then reevaluated with an accurate model to reduce noise, and the top design from this reduced list has a high alignment probability of being the optimal. This is known as a horse-race approach that is effective for complex systems with non-linearities and discrete variables and outperforms the blind pick selection method.

For this search problem, let Θ represent the search space of the optimization variables, which are the sizes of hydrogen production subsystems. Let Θ_N denote the set of N designs that are uniformly sampled from the search space Θ . When N is large (e.g., $N = 1000$ or more), the selected Θ_N is considered to represent the total search space Θ . Let G represent the “good enough” subset within Θ_N , also referred to as the top- G designs, which would include the optimum design. Let S be the subset consisting of the top- S designs from Θ_N , in which case the best three designs ($k = 3$) of S are highly likely to be part of G . Thus, the designs belonging to G and S , or $G \cap S$, form a set of “truly good-enough” designs within G with a high alignment probability (AP) of being the optimum. This is mathematically

expressed as $AP = P[|G \cap S| \geq k] = 0.95$, which is the probability that there are at least k truly good enough designs in S , where k is the alignment level. The OO theory [21] predicts the size of the selected subset S using $s(k, g) = e^{z_1 k z_2 g^{z_3}} + Z_4$, with $g = 50$, $z_1 = 8.1998$, $z_2 = 1.9164$, $z_3 = -2.0250$ and $z_4 = 10$. The size of S is found to be 21. This means that the first 21 designs need to be evaluated using the accurate model, to remove the errors introduced through the use of a simple model and to select the best among them, with a probability of 95% being the optimum. The coefficients are obtained from a table of regression coefficients, developed for a large set of problems for an $AP = 0.95$ [21]. They correspond to a low error bound of $U = [-0.5, 0.5]$ per unit, since the applied simple model yields results that are rather close to those of the accurate model for operating cost, energy production, and utilization. Figure 5 shows a flowchart of the OO process just described identifying “really good-enough” designs with a 95% probability of being the optimum.

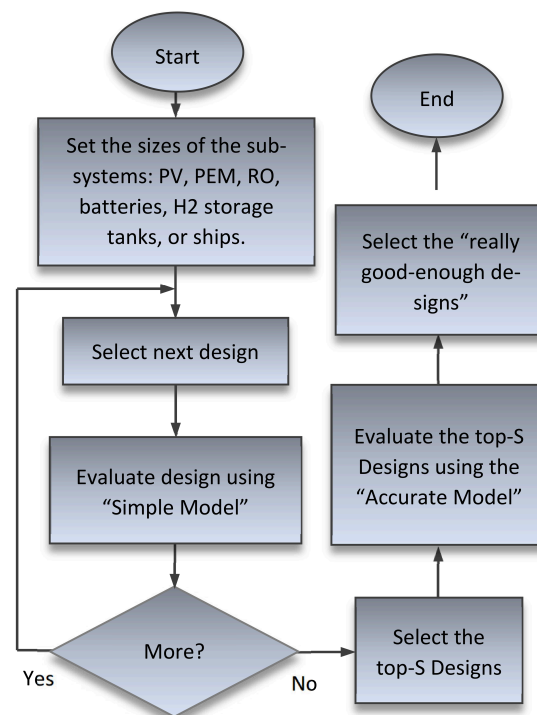


Figure 5. Ordinal Optimization flowchart.

The design of the GH production and shipping process is evaluated by simulation using the models developed in Sections 4 and 5, which are integrated using an energy management system (EMS) to create a comprehensive simulation for the operation of the GH plant. The logic of the EMS is shown in Figure 6, as upgraded from an earlier version [10]. First, the daily energy produced by the PV plant is forecasted, then the hydrogen production of the PEM plant is scheduled, which is followed by the water production of the RO unit and energy required for compressing GH into the storage tank. The excess energy of the PV plant is used to charge the batteries to maintain operation when solar energy is unavailable. The PEM electrolyzer operates at two levels: a higher output during the day and a lower output of 5% of its rated output at night. The low operational output at night is obtained through the battery; it is a minimum output to ensure continuity of the PEM electrolyzer operation and keep the battery size at a minimum. The total daily hydrogen production follows the forecasted solar energy of Tunis, with an adaptive method to adjust the schedule to actual solar conditions. Production is raised when sufficient solar energy is available and the battery SOC increases, and it is reduced when the battery SOC decreases.

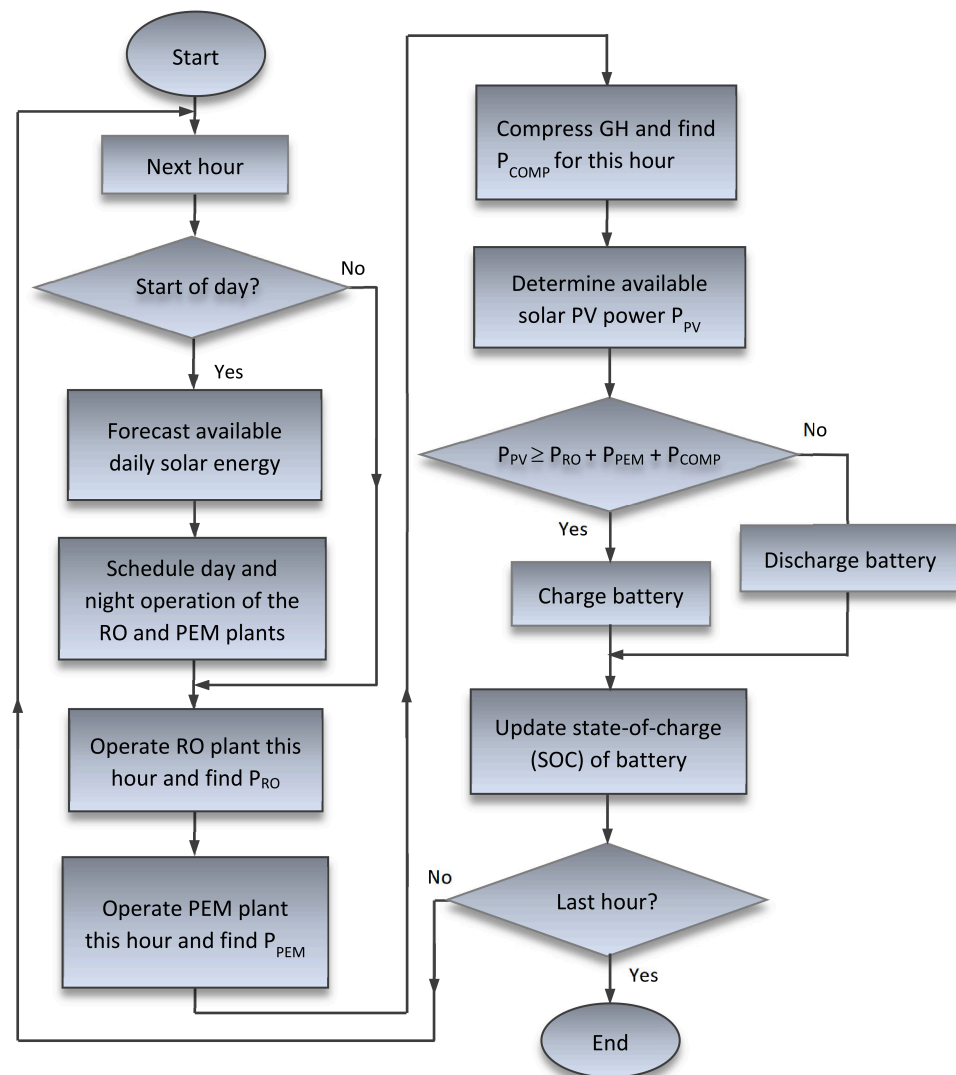


Figure 6. Energy management system logic.

The simulation model evaluates the designs to estimate the specific cost of hydrogen production for each. The simple model of the OO process simulates the operation of the plant over two weeks, or 336 h, and then scales it to one year for energy utilization and cost assessment. Given that the year has 8760 h, the number of simulations is thus reduced by a factor of 26.

7. Results and Discussion

This study explores the design of a solar-powered GH production plant with an output of approximately 60 t/day. The plant's capacity is determined based on annual solar radiation data for Tunis. The overall cost function, Equation (1), includes the annualized capital cost ($IC(n)$) for each design n corresponding to a set of subsystem sizes of the GH plant, and the operation and maintenance (OM) costs ($O(n)$). The OM costs are estimated at 2.0% annually of the investment for all subsystems, except for the PV plant, which has an OM cost of 1.5% annually. For the economic analysis, a system lifespan of 20 years was assumed, along with an interest rate of 7%. Table 1 outlines the cost parameters for the primary system components. The cost of the PV solar system [32] includes inverters, structural supports, and installation.

Table 1. Cost data of primary components.

PV system	\$0.466/W [32]
PEM electrolyzer	\$18,300/(kg/h H ₂) [33]
H ₂ compression	\$450/(kg/h) for 100 bar [34]
Sodium ion battery	\$44/kWh [35]
Hydrogen ship hull	\$2.7/kg of Ship DWT [20]
Fuel cell	\$1500/kW [36]
Type IV storage tank @500 bar	\$243.4/kg [30]

7.1. Local-Use Scenario

The different subsystem sizes used in the designs are specified in Table 2. There are five different design values for each subsystem, which yields a total of $5^6 = 15,625$ designs that represent a rather large search space. Let us note that any solution obtained corresponds to one of the combinations of the design values. We will show that by selecting only 1000 from these designs that cover the search space, and that by applying the OO process on this subset, we will obtain high-quality solutions with a LCOH very nearly equal to the best obtained through an exhaustive search of the 15,625 designs. The 1000 designs selected correspond to the values in Table 2 that are underscored; their number is $5^3 \cdot 2^3 = 1000$. In this scenario, the simple model of the OO platform was used to evaluate the 1000 design options in 7.92 s, and some of the top 21 designs are listed in Table 3, all having a 500-bar hydrogen storage pressure. The ordered performance curve of the best 250 designs is shown in Figure 7. Its shape indicates that there are very few designs of high quality, while the rest become progressively more mediocre. The hydrogen production of about 60 t/day is determined mainly by the size of the PV plant and to a lesser extent by the battery size of the system being analyzed. This production level exceeds those of most currently operating commercial green hydrogen plants, which typically produce less than 10 t/day [37].

Table 2. Subsystem design sizes.

Subsystem Size	Design Values
PV (MW)	810, 840, 870, 900, <u>930</u>
PEM (t/day)	<u>100</u> , <u>102</u> , <u>105</u> , <u>107</u> , <u>110</u>
Battery (MWh)	<u>1620</u> , <u>1674</u> , <u>1728</u> , <u>1782</u> , <u>1836</u>
RO (m ³ /h)	<u>37.5</u> , 56.25, <u>75.0</u> , 93.75, 112.5
H ₂ Pressure (bar)	<u>300</u> , 350, 400, 450, <u>500</u>
H ₂ Storage (days)	<u>5</u> , 7, 9, 11, <u>13</u>

The running of the accurate model on the top 21 designs took 4.3 s to identify the best three designs, which ranked 20, 10, and 17, respectively, in the simple model evaluations. These top three designs are shown in Table 4, with annual PV energy production and subsystems' energy consumption, as evaluated by the accurate model. The top design produces 65.72 t/day at a cost of \$2.945/kg. Here, let us note that the rank of the best solutions obtained through the simple model are well within the limit of the top 21 designs predicted by the OO process. Each of the three best solutions has a 95% alignment probability of being the optimum.

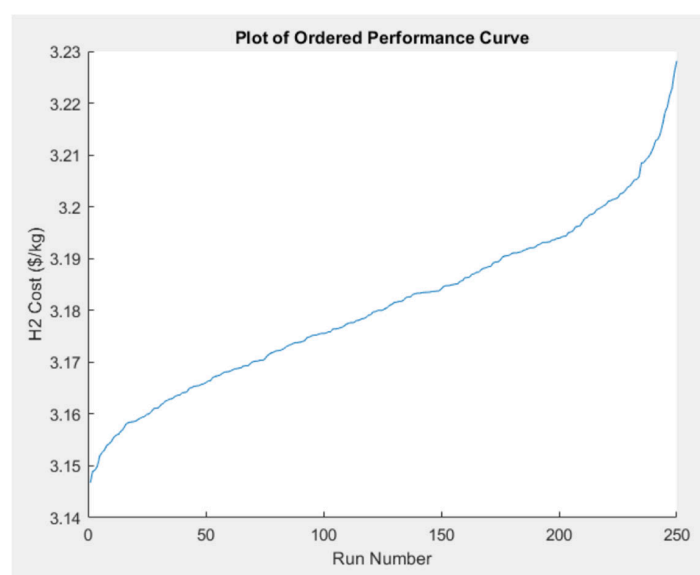
The best design most effectively uses the available assets to produce as much hydrogen as possible, which will cause the levelized cost of hydrogen to be as low as possible. For example, in Design 2, the increase in the battery size allowed production to increase from 23,989 to 24,082 t/year. However, the LCOH increased from \$2.945 to \$2.949/kg due to the increased battery investment. The results in Table 4 may be interpreted as a kind of sensitivity analysis. When we increased the battery size from 1620 to 1674 MWh, we fell onto Design 2, which has a higher LCOH. And when we reduce the size of the PV from 930 down to 900 MW, we fall onto Design 3, which also has a higher LCOH of \$2.953/kg.

Table 3. The top twenty-one “good-enough” designs—local use.

No.	PV MW	BT MWh	PEM t/day	RO m ³ /h	H ₂ Store t	H ₂ Prod. t/day	H ₂ Cost \$/kg
1	930	1836	100	37.50	261	62.85	3.15
2	900	1836	100	37.50	261	61.58	3.15
...	...	...	...	...	...	...	...
5	930	1728	100	37.50	261	62.07	3.15
...	...	...	...	...	...	...	...
9	930	1836	102	37.50	267	63.03	3.15
10	930	1674	100	37.50	261	61.68	3.15
...	...	...	...	...	...	...	...
17	900	1620	100	56.25	261	60.05	3.16
...	...	...	...	...	...	...	...
20	930	1620	100	37.50	261	61.25	3.16
21	870	1620	100	37.50	261	58.80	3.16

Table 4. The top three designs—local use.

Run Number	1	2	3
PV Size (MW)	930	930	900
Battery Size (MWh)	1620	1674	1620
PEM Size (t/day)	100	100	100
RO Size (m ³ /h)	37.5	37.5	37.5
Net H ₂ Storage (t)	261	261	261
Storage Pressure (bar)	500	500	500
PV Energy (GWh)	1434.9	1434.9	1388.6
PEM Energy (GWh)	1347.0	1352.1	1308.3
Compression (GWh)	59.6	59.7	58.0
RO Energy (GWh)	1.01	1.01	0.99
Excess Energy (%)	1.53	1.17	1.17
Total Investment (M\$)	649.8	652.2	635.8
Capex + Opex (M\$/year)	70.6	71.0	69.23
H ₂ Production (t/day)	65.72	65.98	64.24
H ₂ Production (t/year)	23,989	24,082	23,447
H ₂ Cost (\$/kg)	2.945	2.949	2.953

**Figure 7.** Ordered performance curve (OPC)—local-use scenario.

7.2. Tunis-to-Genoa Shipping Scenario

Using the same computational model, the production of GH in NA and its shipping to Europe are investigated in two case studies: Tunis to Genoa, and Tunis to Hamburg. The Tunis-to-Genoa route has a sea distance of 856 km, which is covered by a ship model at a speed of 41.5 km/h or 22.5 knots. The one-way trip takes about one day, with docking and unloading lasting 2.86 days. Here also we define 15,625 design options that we will analyze using an exhaustive search to find the best design. The PV, battery, PEM, H₂ pressure, and RO sizes are as in Table 2, and the ship sizes are as shown in Table 5. Here also we will select 1000 of these options, defined by the underscored values in Tables 4 and 5, and we will show that the solutions obtained through OO are “really good-enough” designs and differ from the optimum by a very tiny margin. The OO platform was used to simulate the operation of the 1000 designs, and the evaluation of these designs using a simple model took 7.65 s. Some of the top 21 designs, all at a pressure of 500 bar, are shown in Table 6.

Table 5. Subsystem design sizes.

Name of Subsystems	Design Values
Ship (Length (m), Number) Tunis–Genoa	(120, 2), (<u>120</u> , 3), (<u>120</u> , 4), (120, 5), (130, 3)
Ship (Length (m), Number) Tunis–Hamburg	(120, 5), (130, 3), (130, 4), (<u>130</u> , 5), (<u>130</u> , 6)

Table 6. The top 21 shipping designs—Tunis to Genoa.

Run	PV MW	BT MWh	PEM t/day	RO m ³ /h	H ₂ Stor. (t)	H ₂ Prod. t/day	H ₂ Cost \$/kg
1	900	1836	110	37.5	111	62.27	4.05
2	900	1836	107	37.5	111	62.11	4.06
...	...	...	...	...	...	...	...
14	930	1620	110	37.5	111	61.93	4.07
...	...	...	...	...	...	...	...
16	930	1620	107	37.5	111	61.77	4.07
17	900	1728	110	37.5	111	61.47	4.07
...	...	...	...	...	...	...	...
20	930	1620	105	37.5	111	61.61	4.07
21	900	1836	107	75	111	62.11	4.07

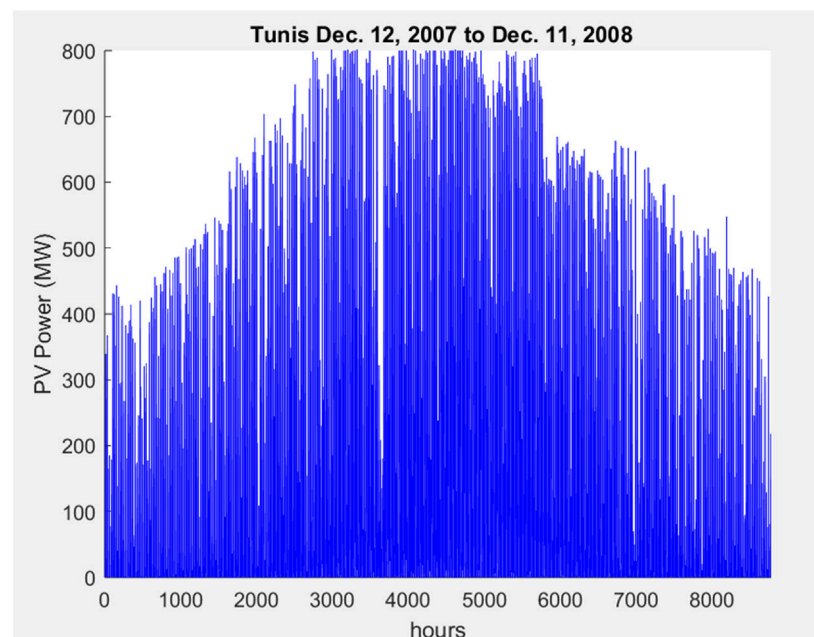
The accurate model took 4.3 s to evaluate the top 21 designs and identify the top three designs, which ranked 14, 16, and 17 in the simple model evaluation. The top three designs when evaluated using the accurate model are summarized in Table 7, with annual PV energy production and subsystems’ energy consumption. The optimal setup for GH transport to Genoa requires three ships, each of 120 m, completing 220 trips per year.

It is worth noting that the selected size of the PV plant for the best design in the Tunis–Genoa scenario is still 930 MW with a battery size of 1620 MWh, as obtained in the local-use scenario. It seems that these production assets match the three ships of 120 m, with a hydrogen storage capacity of 111 t/ship. However, Design 2 has a lower PV size plant, at 900 MW, with a larger battery of 1728 MWh, and is able to deliver slightly less hydrogen at a slightly higher cost of \$3.903/kg. Let us also note that the transportation of GH from Tunis to Genoa caused an increase in the investment from \$649.8 to \$800.6 million, which is \$150.8 million over a distance of 856 km, or an average increase of \$17.6 million per 100 km. In this respect, the LCOH increased from \$2.945/kg to \$3.902/kg, which is an increase of \$0.112/kg per 100 km.

Table 7. Top three designs in Tunis–Genoa shipping scenario.

Run Number	1	2	3
PV Size (MW)	930	900	930
Battery Size (MWh)	1620	1728	1620
PEM Size (t/day)	110	110	107
RO Size (m ³ /h)	37.50	37.5	37.5
H ₂ (t/ship)	111	111	111
Storage Pressure (bar)	500	500	500
Ship Length (m)	120	120	120
Number of Ships	3	3	3
Trips per Year	225	220	225
PV Energy (GWh)	1434.9	1388.6	1434.9
PEM Energy (GWh)	1336.9	1307.9	1339.8
Compression (GWh)	61.8	60.3	61.8
RO Energy (GWh)	1.02	1.00	1.02
Excess Energy (%)	2.07	1.05	1.88
Total Investment (M\$)	800.6	791.4	798.8
Capex + Opex (M\$/year)	93.2	92.4	93.0
H ₂ Production (t/day)	66.72	65.61	66.51
H ₂ Production (t/year)	24,352	23,948	24,277
H ₂ Delivery (t/year)	23,887	23,673	23,814
H ₂ Cost (\$/kg)	3.902	3.903	3.905

Figures 8 and 9 show that GH production peaks during periods of maximum PV output (hours 3000–5500). Figure 10 indicates the number of fills, and therefore trips, needed to maintain continuous production and loading in the high-production period.

**Figure 8.** PV energy production over one year.

7.3. Tunis-to-Hamburg Shipping Scenario

The shipping distance from Tunis to Hamburg is approximately 4350 km. Transporting over this distance with a ship travelling at 41.5 km/h (22.5 knots) requires a one-way journey of about 5 days, and an additional 3.42 days each for the filling and unloading of a ship. Here we use the same subsystem sizes as in Table 5 but choose the last row for the ship sizes and numbers for this scenario. The simple model simulated the selected 1000 designs over a two-week period in 7.66 s.

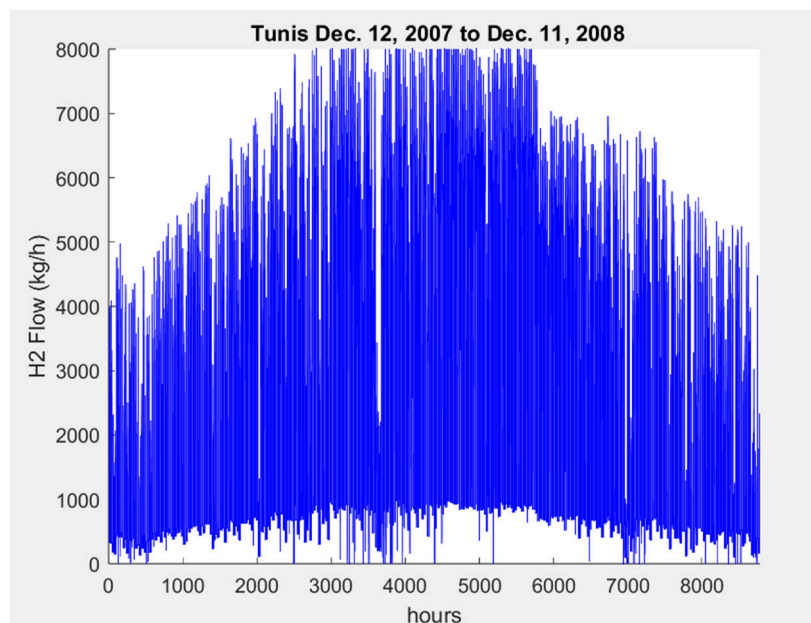


Figure 9. GH production over one year.

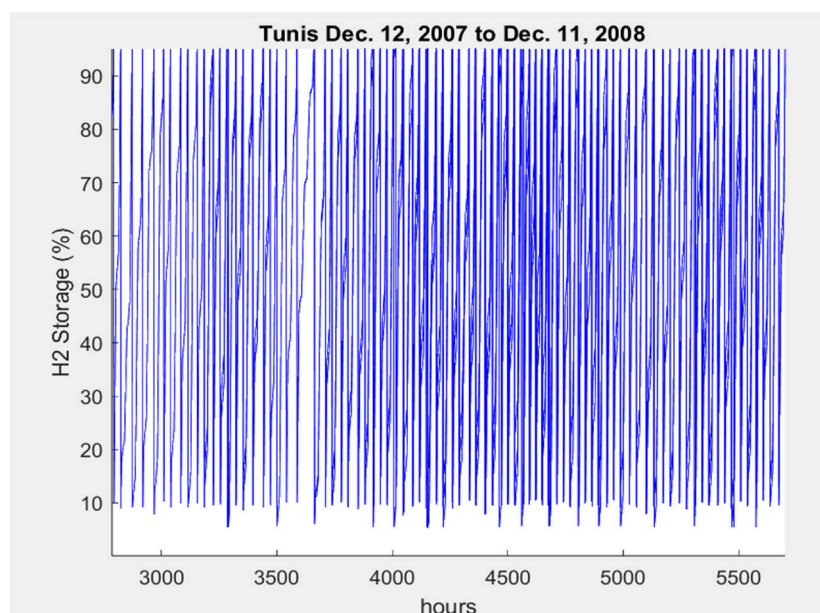


Figure 10. Filling of ships for Tunis–Genoa for hours 3000 to 5500.

Table 8 lists some of the top 21 designs as obtained by the simple model simulation, all of which have storage pressures of 500 bar. Running the accurate model for these top 21 designs took 4.91 s and identified the best three designs, which ranked 18, 5, and 1 in the simple model evaluation, respectively. Let us note here that a rank of 18 for the best solution is acceptable since it is not at the edge of the top 21 “good-enough” solutions.

Table 9 summarizes the characteristics of these top three designs, respectively, when evaluated using the accurate model. The best design produces 23,350 t of hydrogen annually, at an average of 63.97 t/day, and has a delivery of 23,178 t of GH, annually yielding a production and shipping cost of \$6.382/kg. Here, also note that the transportation of GH from Tunis to Hamburg caused an increase in the investment from \$649.8 million to \$1075.7 million, which is an increase of \$425.9 million over a distance of 4,350 km, or an average increase of \$9.79 million per 100 km. In this respect, the LCOH increased from \$2.945/kg to \$6.382/kg, which is an increase of \$0.079/kg per 100 km.

Table 8. The first twenty designs: shipping from Tunis to Hamburg.

Run	PV MW	BT MWh	PEM t/day	RO m ³ /h	H ₂ Stor. (t)	H ₂ Prod. t/day	H ₂ Cost \$/kg
1	870	1836	110	37.5	141	60.98	6.44
2	870	1836	107	37.5	141	60.82	6.45
...	...	...	...	...	...	...	...
4	870	1836	105	37.5	141	60.62	6.46
5	870	1782	110	37.5	141	60.61	6.46
...	...	...	...	...	...	...	...
17	870	1782	102	37.5	141	60.13	6.49
18	870	1728	110	37.5	141	60.21	6.49
...	...	...	...	...	...	...	...
20	900	1620	102	37.5	141	60.21	6.49
21	900	1674	100	75.0	141	60.44	6.49

Table 9. The top three designs: Tunis–Hamburg.

Run Number	1	2	3
PV Size (MW)	870	870	870
Battery Size (MWh)	1728	1782	1836
PEM Size (t/day)	110	110	110
RO Size (m ³ /h)	37.5	37.5	37.5
H ₂ (t/ship)	141	141	141
Storage Pressure (bar)	500	500	500
Ship Length (m)	130	130	130
Number of Ships	6	6	6
Trips per Year	169	169	169
PV Energy (GWh)	1342.3	1342.3	1342.3
PEM Energy (GWh)	1268.0	1270.8	1273.0
Compression (GWh)	57.9	57.9	57.9
RO Energy (GWh)	0.971	0.971	0.972
Excess Energy (%)	0.82	0.61	0.46
Total Investment (M\$)	1075.7	1078.1	1080.5
Capex + Opex (M\$/year)	147.9	148.3	148.7
H ₂ Production (t/day)	63.97	64.10	64.21
H ₂ Production (t/year)	23,350	23,397	23,435
H ₂ Delivery (t/year)	23,178	23,226	23,263
H ₂ Cost (\$/kg)	6.382	6.386	6.392

7.4. Validation

The model was validated by comparing its results with existing studies. For the optimal designs, presented in Tables 4, 7 and 9, the average specific energy consumption is 55.2 kWh/kg H₂ for PEM electrolysis, 4.56 kWh/m³ for the reverse-osmosis system, and 2.49 kWh/kg H₂ for compression. Table 10 shows that specific energy consumptions across subsystems are around the mid-range of previous studies, which provides fair validation of the mathematical models used.

To validate the proposed ordinal optimization (OO) framework, an exhaustive search was performed over the sampled design space of 15,625 candidate configurations for the local-use and shipping scenarios. The results, presented in Table 11, demonstrate that the OO method significantly reduces the computational time while maintaining excellent solution quality. For both the local-use and Tunis–Hamburg scenarios, the OO framework

identified the same optimal design and corresponding LCOH, as obtained by the exhaustive search. For the Tunis–Genoa scenario, the LCOH obtained using the OO method differed from the exhaustive search (ES) result by only 0.15%. These findings confirm that the proposed OO framework can efficiently explore large design spaces with minimal computational effort and maintain a good solution quality.

Table 10. Comparison between this and previous studies.

Subsystem	Specific Energy	Earlier Studies
PEM (kWh/kg H ₂)	55.2	54.6 [38] 56.8 [7]
Reverse Osmosis (kWh/m ³)	4.56	3.7 [2] 3.5–6 [39,40]
Compression (kWh/kg H ₂)	2.49	2.2–4 [41,42]

Table 11. Times and solution quality of best designs.

Case Study	Exhaustive Search Time (s)	OO Search Time (s)	Best LCOH (\$/kg)	
			Using ES	Using OO
Local Use	3237.2	12.2	2.945	2.945
Tunis–Genoa	3125.5	12.0	3.882	3.902
Tunis–Hamburg	3251.3	12.6	6.382	6.382

7.5. Sensitivity Analysis

A sensitivity analysis was conducted to evaluate the effect of variations in the size of the major system components on the levelized cost of hydrogen (LCOH). This analysis focuses on the sizes of the PV plant, the PEM electrolyzer, and the battery storage for the local-use scenario. We added to these the length of the ship in the transportation scenarios. These subsystems account for the largest proportion of the total capital investment and therefore are expected to have the greatest impact on the overall hydrogen production cost. The size of the PV plant of the best design was changed by ± 15 MW; then, the size of the battery storage was changed by ± 27 MWh, after which the PEM electrolyzer capacity was changed by ± 1 t/day, and finally the length of the ship was changed by ± 5 m for the transportation scenarios. Each parameter change was done individually, allowing us to quantify its effect on the LCOH, and Table 12 presents the results of this sensitivity analysis. In the local-use scenario, note, as shown in Table 12, that increasing the PV plant by 15 MW causes the LCOH to drop from \$2.945 to \$2.940/kg as more hydrogen is produced. However, increasing the battery capacity by 27 MWh caused the LCOH to increase to \$2.947/kg as this action did not result in an appropriate increase in GH production. For the Tunis-to-Genoa scenario, increasing the ship length caused the LCOH to rise to \$2.906, probably due to the additional investment, while decreasing the ship length caused the LCOH to increase significantly to \$4.008/kg due to a drop in the delivery capability of the ships.

Table 12. Change in LCOH due to size variation in PV, PEM, battery, and ship length.

Scenario	Plant	Best Design Sizes	-----LCOH (\$/kg)-----		
			Best Design	Step Incr.	Step Decr.
Local Use	PV	930 MW	2.945	2.940	2.948
	PEM	100 t/day		2.945	2.943
	Battery	1620 MWh		2.947	2.943

Table 12. *Cont.*

Scenario	Plant	Best Design Sizes	-----LCOH (\$/kg)-----		
			Best Design	Step Incr.	Step Decr.
Tunis to Genoa	PV	930 MW	3.902	3.910	3.895
	PEM	110 t/day		3.901	3.902
	Battery	1620 MWh		3.911	3.902
	Ship	120 m		3.906	4.008
Tunis to Hamburg	PV	870 MW	6.382	6.398	6.371
	PEM	110 t/day		6.380	6.385
	Battery	1728 MWh		6.384	6.382
	Ship	130 m		6.491	6.759

8. Conclusions

This paper presented an effective methodology combining simulation and ordinal optimization (OO) to optimize the design of a large-scale green hydrogen (GH) production plant in North Africa. Solar-powered desalination and PEM electrolysis were used to produce GH that is stored at high pressure for local use or for maritime shipment to Europe. Battery storage ensures continuous operation, and the approach optimally sizes PV panels, batteries, desalination units, electrolyzers, storage tanks, and shipping to achieve about 60 t of hydrogen per day at minimal cost. The large search space is formed of designs with different combinations of subsystem sizes; it is first efficiently screened using a simple model based on simulating system operation over a two-week period. Their yearly hydrogen production costs are then estimated through scaling, and the designs are ranked in order of increasing cost. The top-S designs are then evaluated using an accurate model based on a full-year simulation to determine their hydrogen production costs and identify the top design with a high alignment probability of being the optimum. This study details the infrastructure investments in renewable energy, production, storage, and transport which are needed to build a sustainable hydrogen supply chain. This will help create employment and workforce development opportunities in both North Africa and Europe.

Two main scenarios were explored in this study: the first is for local hydrogen utilization in North Africa, where the GH produced is stored in Type IV storage tanks; the second is exporting GH to Europe through maritime transportation. In the local-use scenario, the OO technique identified an optimal configuration, with the hydrogen production and storage cost at \$2.945/kg H₂. Two case studies were conducted to illustrate the export scenarios. The first is a system for exporting GH from Tunis to Genoa, with a cost of production and transport estimated at \$3.902/kg H₂. The second case study is to transport GH from Tunis to Hamburg, with a cost of production and transportation of \$6.382/kg H₂.

A sensitivity analysis demonstrated the ability of the proposed optimization framework to identify the component changes that have a positive economic impact on the LCOH and guide the planner in fine-tuning the proposed design sizes.

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Abbreviations

The following abbreviations are used in this manuscript:

GH	Green hydrogen
OO	Ordinal optimization
LOCH	Levelized cost of hydrogen
MILP	Minimum integer linear programming
LOHC	Liquid organic hydrogen carrier
LH	Liquified hydrogen
DG	Distributed generator
FCHEV	Fuel cell hybrid electric vehicle
NA	North Africa
PV	Photovoltaic
RO	Reverse osmosis
PEM	Polymer electrolyte membrane
EMS	Energy management system
GA	Genetic algorithm
ERD	Energy recovery device
SOC	State of charge
HDPE	High-density polyethylene
CCF	Composite carbon fiber
CF	Capacity factor
AP	Alignment probability

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