Techno-economic Analysis of Green Hydrogen Production from Offshore Wind Energy in Costa Rica

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Thesis to obtain the Master of Science Degree in

Energy Technologies for Sustainable Development

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January 2023

Acknowledgements

“Indiscutiblemente a mi familia que siempre me ha apoyado incondicionalmente

A mis seres queridos por aportar tanto en mi vida”

“Undisputedly to my family for always supporting me unconditionally

To my beloved ones for bringing so much into my life.”

Abstract

This thesis explores the techno-economics behind the production of green hydrogen from offshore wind energy, more specifically, from Punta Descartes offshore wind farm. The Punta Descartes project is in its earliest identification phase, and its capacity has been estimated at 540MW, which would represent nearly a 14% increase in the national installed power. This significant increase in capacity is not feasible either with the current state of the national transmission grid or in the forecasted expansion plans.

Hence, three operational cases are studied in this work and compared to a reference scenario. The first case presents a dedicated hydrogen & oxygen production; the second and third cases include hydrogen-oxygen-electricity production using proton exchange membrane and alkaline electrolysis technologies, respectively. Different assumptions and costs apply in each case, thus, the technical and economic characteristics are analyzed.

Based on economic indicators such as the net present value, the internal return rate of the project and levelized cost of hydrogen; alkaline technology offers to the project higher benefits than the rest of the cases. Although the production of hydrogen and oxygen greatly improved the economics of the reference case, the proposed offshore wind + electrolysis project is not economically feasible.

Finally, a sensibility analysis is carried out for the selected best case. This analysis shows the impact that different parameters have on the net present value and the internal return rate of the project.

Keywords: Hydrogen; Wind Power; Offshore Wind; Costa Rica; Techno-economic; Feasibility

Resumo

Esta tese explora os fatores tecno-econômicos da produção de hidrogênio verde a partir da energia eólica offshore, mais especificamente, a partir do projeto Punta Descartes. O projeto Punta Descartes está na sua fase inicial de identificação, e a sua capacidade foi estimada em 540MW, o que representaria um aumento de quase 14% na potência instalada nacional. Este aumento significativo da capacidade não é viável nem com o estado atual da rede nacional de transmissão nem com os planos de expansão previstos.

Sendo assim, três casos operacionais são estudados neste trabalho e comparados com um cenário de referência. O primeiro caso apresenta uma produção dedicada de hidrogênio e oxigênio; o segundo e o terceiro caso incluem a produção de hidrogênio, oxigênio e eletricidade utilizando tecnologias de membrana de troca de protões e de eletrólise alcalina, respectivamente. Aplicam-se suposições e custos diferentes em cada caso, analisando as caraterísticas técnicas e econômicas.

Com base em indicadores econômicos tais como o valor presente líquido, a taxa de retorno interno do projeto e o custo nivelado do hidrogênio; a tecnologia alcalina oferece ao projeto maiores benefícios do que o resto dos casos. Embora a produção de hidrogênio e oxigênio tenha melhorado muito a economia do caso de referência, o projeto proposto de vento offshore + eletrólise não é economicamente viável.

Finalmente, é realizada uma análise de sensibilidade para o melhor caso selecionado. Esta análise mostra o impacto que diferentes parâmetros têm no valor presente líquido e na taxa de retorno interno do projeto.

Palavras-chave: Hidrogênio; Energia Eólica; Eólica Offshore; Costa Rica; Tecno-econômico; Viabilidade

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Abbreviations

ALK	Alkaline Electrolysis.
CCUS	Carbon Capture Usage and Storage.
D&C	Development and Consenting.
D&D	Decommissioning and Disposal.
DES	Direct Electrolysis of Seawater.
FID	Final Investment Decision.
FOWT	Floating Offshore Wind Turbine.
GWEC	Global Wind Energy Council.
I&C	Installation and Commissioning.
ICE	Acronym in Spanish for “Instituto Costarricense de Electricidad”.
IPCC	Intergovernmental Panel on Climate Change.
IRR	Internal Return Rate.
LCOE	Levelized Cost of Electricity.
LCOH	Levelized Cost of Hydrogen.
LCOO	Levelized Cost of Oxygen.
MINAE	Acronym in Spanish for “Ministerio de Ambiente y Energía” in Costa Rica.
NDP	National Decarbonization Plan.
NPV	Net Present Value.
O&M	Operation and Maintenance.
OEM	Original Equipment Manufacturer.
OWF	Offshore Wind Farm.
OWMRA	Offshore Wind Market Readiness Assessment.
P&A	Production and Acquisition.
PEME	Proton Exchange Membrane Electrolysis.
SOE	Solid Oxide Electrolysis.
SRMC	Short-Run Marginal Cost.
UNFCCC	United Nations Framework Convention on Climate Change.
VRES	Variable Renewable Energy Sources.
WACC	Weighted Average Cost of Capital.

Nomenclature

C_n	Production costs in year n (USD, EUR).
Q_n	Energy output in year n (kWh, MWh, GWh).
d	Discount rate (as a fraction).
N	Number of years in the period under analysis.
U_i	Mean wind speed in hour i (m/s) when creating the synthetic data set.
$\overline{U}$	Overall mean wind speed (m/s).
δ	Diurnal pattern strength (a number from 0 to 1).
Ø	The hour of peak wind speed (a number from 1 to 24).
z_{hub}	Hub height of the wind turbine (m).
z_{anem}	Anemometer height (m).
z_0	Surface roughness (m).
$v(z_{hub})$	Wind speed at hub height (m/s).
$v(z_{anem})$	Wind speed at anemometer height (m/s).
RDR	Real Discount Rate (as a fraction).
InR	Inflation rate (as a fraction).

CHAPTER 1

Introduction

This first chapter aims at presenting the reader with the opportunity of seeing the research topic from the author's eyes. It is presented in three sub-sections; the motivation, objectives and the outline of the thesis developed.

1.1 Motivation

Our civilization is nowadays experiencing drastic decision-making times; challenging scenarios include climate change, pandemics, armed conflicts or energy crises, among others. All these complex situations bring to light the need of more resilient systems, ether for social structures, economic growth and for production environments.

Addressing the climate change front, the creation of the Intergovernmental Panel on Climate Change (IPCC) in 1988 marks a starting point for joint efforts against it, but, as the European Commission states:

> *Global efforts to fight climate change really began in 1992, when countries around the world signed an international treaty called the United Nations Framework Convention on Climate Change (UNFCCC). [1]*

Even though some actions have been adopted to decelerate the degradation of our environment, it has not been enough to repay for the damage done, mostly since the beginning of the Industrial Revolution in the 1800s. The most recent global effort to remediate the actual situation is the Paris Agreement, where 174 countries committed to keeping the rise of global average temperature below 2°C, to build resilience against climate change and to align financial flows with low greenhouse emissions and climate-resilient development.

Most of the greenhouse gas emissions derive from energy production, and as shown in Figure 1.1, around 77% of the energy consumed globally comes from fossil fuels. Furthermore, projections for 2050 show that energy demand is expected to flatten after 2030, mostly due to the efficiency gains related to electrification [2].

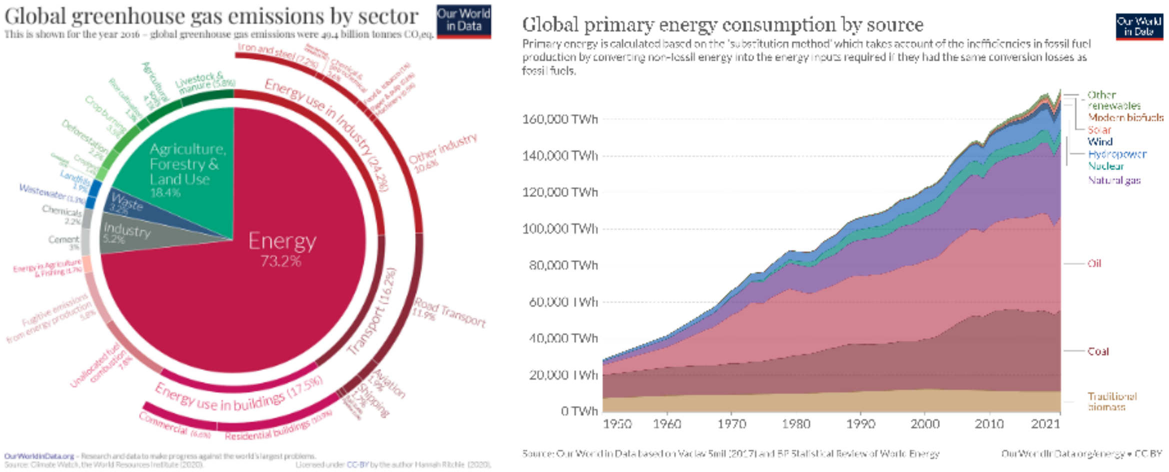


Figure 1.1 Global greenhouse gas emissions by sector & Global energy consumption by source. Adapted from [3] & [4] respectively.

Electrifying all energy demanding sectors is a hard task to carry out, and the share of renewable energies in the electricity mix should grow in order to attain a low carbon production. Here, hydrogen can play a significant role in both challenges: as energy carrier in hard-to-abate fields, such as heavy transport and industrial heat, but also as a storage system to excess energy from variable renewable energy sources (VRES).

In this transition scenario, Det Norske Veritas (DNV) forecasts that hydrogen will only supply 5% of global energy demand by 2050, this represents only a third of the of what would be needed for a net zero emissions scenario, and green hydrogen from dedicated renewables and from the grid will become dominant [2]. What is more, in 2021 hydrogen production was near 81% sourced from natural gas and coal, as Figure 1.2 shows.

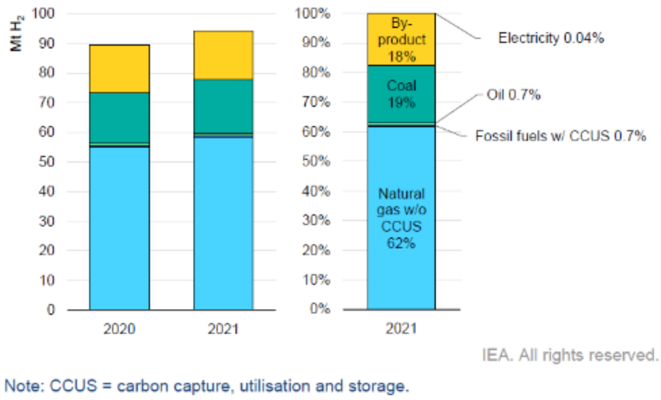


Figure 1.2 Hydrogen production mix. Adapted from [5]

With all of the aforementioned conditions, Costa Rica can take advantage of the momentum that the renewable energies sector is experiencing. Furthermore, the country produces more than 98% of its electricity from renewable sources, however, in the last 5 years, it has not been able to allocate all of its electricity surplus (about 917,4GWh/y) in the regional market, and only 48% of it is exploited. [6]

In addition to the aforementioned advantages of the country, there are some future renewable energy projects in the horizon, for instance, the offshore wind farm (OWF) Punta Descartes could bring a maximum estimated installed power of 540MW to the national grid.

With a total installed power of 3.674MW [7], Punta Descartes would increase power generation capacity in more than 14%, hence, taking into account the actual surplus of green electricity and the projected power capacity growth, hydrogen presents an attractive option for energy storage and/or carriage.

Finally, the impact of hydrogen as energy vector in Costa Rica is magnified by the fact that 64,5% of the energy consumption goes to transportation sector, which runs on fossil fuels [8]. Hence, this research study explores the techno-economical context and variables involved in the possible production of green hydrogen from the OWF Punta Descartes, and it represents the first exploration of the idea of offshore hydrogen production in Costa Rica.

1.2 Objectives

This research aims to uncover the potential economic benefits of hydrogen production at an OWF in Costa Rica, specifically from the already identified project, Punta Descartes. The identification study of Punta Descartes concluded that the project is technically and environmentally feasible but not economically feasible. Aside of being economically unviable, the project also would be limited by the national grid capacity, hence, this thesis work intends to answer the following question:

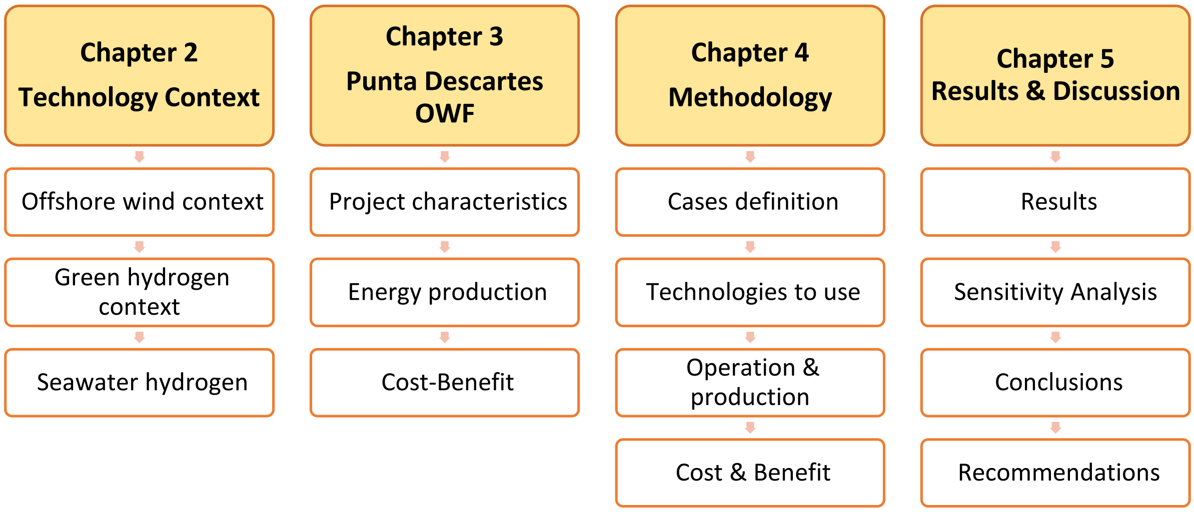
How would hydrogen production impact the feasibility of Punta Descartes offshore wind farm?

As the country already generates almost 100% of its electricity from renewable resources, and actual production capacity is curtailed at national level, hydrogen production poses an opportunity to reduce the Costa Rican energy infrastructure's carbon footprint. Alongside with the aforementioned question, some sub-questions also surface and will be answered throughout this report:

- What is the offshore wind context at the international and national levels?
- What is the green hydrogen context at the international and national levels?
- How much hydrogen would Punta Descartes OWF produce?
- What would be the optimal size of the hydrogen production equipment?
- What is the levelized cost of hydrogen production for Punta Descartes OWF?

1.3 Thesis Outline

This research project is structured in 5 chapters, the first one being this introductory chapter and the remaining ones are synthetized in the following schematics:



Chapter 2 comprehends a market level overview of the main technologies involved in the present study, namely, the offshore wind farms and market, the green hydrogen technology and hydrogen production from seawater. Chapter 3 summarizes the most relevant information from the actual identification study of Punta Descartes OWF. In Chapter 4, the methodological approach used in this thesis is described, in this section, all study cases are defined and the models used are described.

Lastly, Chapter 5 collects all the results and calculations, including a sensitivity analysis for the selected economic indicators of the project, the conclusions and further recommendations to deepen in the research questions.

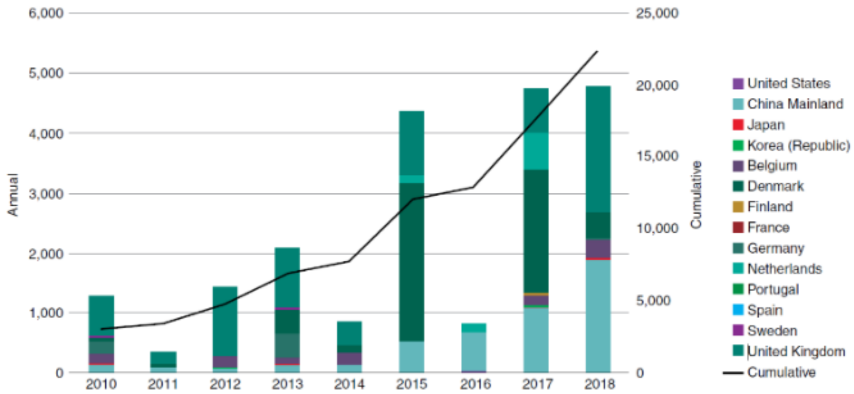
CHAPTER 2

Technology Context

This chapter presents a general overview of the technologies involved in the present work, from a market level perspective. The first section addresses the power generation system, i.e., the offshore wind farm. The second section covers the hydrogen generation technology, starting with a general description of the market and addressing the seawater hydrogen production at the end.

2.1 Offshore Wind

Since 1991 when the first 5MW of offshore wind were commissioned at Vindeby in Denmark, the offshore wind market has been in a growth path as shown in Figure 2.1. Furthermore, according to the Global Wind Energy Council (GWEC), in 2021 this market had its best year with 21,1GW commissioned, and new offshore installations represented 22,5% of all new wind installations. The total offshore capacity sat at 57GW in 2021 which represented a 7% of global wind installations. [9]



Source: Data from BNEF. 2018. 2H 2018 Offshore Wind Market Outlook. Available at: https://www.bnef.com/core/insights/19859

Figure 2.1 Annual offshore wind installations by country and cumulative capacity (MW). Adapted from [10]

Besides the general growth of the offshore wind market, offshore wind farms have been growing in installed power, from a 4,95MW of nameplate capacity of the Vindeby farm to 1,3GW from the Hornsea Two which is the largest OWF in the world up to date [11]. However, this title will soon belong to China as it plans to build a 43,3GW project in Guangdong province, with a planned start of works before 2025, as Bloomberg reports [12].

In addition, offshore wind turbines are growing larger every year, the first ones back in the 90s were in fact, onshore units, but turbines nowadays are specifically designed to withstand the adverse maritime conditions. In 2021 at the event China Wind Power, local Chinese original equipment manufacturers (OEMs) presented 40 new turbine models, with onshore units in the 5-7 MW range and offshore wind units in the 12-16MW range [9]. Regarding rotor size, once more, on October 13th 2022 China announced the production of a 252m diameter unit, beating the previous record of 236m from the Vestas V236-15.0MW model [13].

As the market expands, floating offshore wind represents an opportunity to access a much larger ocean area with high-quality wind resources in waters that are deeper (greater than 60 m) than where fixed-bottom foundations are feasible.

2.1.1 OWF Components

Figure 2.2 shows an schematic of a typical OWF project and the main components are described in [14] as follows:

- **Wind turbines:** The turbine converts kinetic energy from the wind into three-phase alternating current (AC) electrical energy. The wind turbine assembly comprehends 3 main components; the Nacelle, the Rotor and the Tower.
- **Cables:** They must have high chemical and abrasion resistance as well as tensile strength to survive the laying process and withstand wave and tidal loading for exposed sections. There are two main classes for offshore cables, the Export Cables which connect the offshore and onshore substations, and the Array Cables create loops or individual strings connecting all wind turbines to the offshore substation.
- **Turbine foundations:** The foundation provides support for the wind turbine, transferring the loads from the turbine at the tower interface level (typically around 20m above water level) to the sea bed where the loads are reacted. The foundation also provides the conduit for the electrical cables, as well as access for personnel from vessels.
- **Offshore Substation:** Offshore substations are used to reduce electrical losses before export of power to shore. This is done by increasing the voltage, and in some cases converting from AC to direct current (DC) The substation also contains equipment to manage the reactive power consumption of the electrical system including the capacitive effects of the export cables.
- **Onshore Substation:** The onshore substation transforms power to grid voltage, for example 400kV. Where a high voltage DC export cable, the substation will convert the power three phase AC. Many of the electrical components will be similar in specification to the offshore substation, but constraints on weight and space are not as critical. The substation will contain metering equipment to measure electricity exported to the grid.
- **Operation Base:** The operations base supports the operation, maintenance and service of the wind farm.

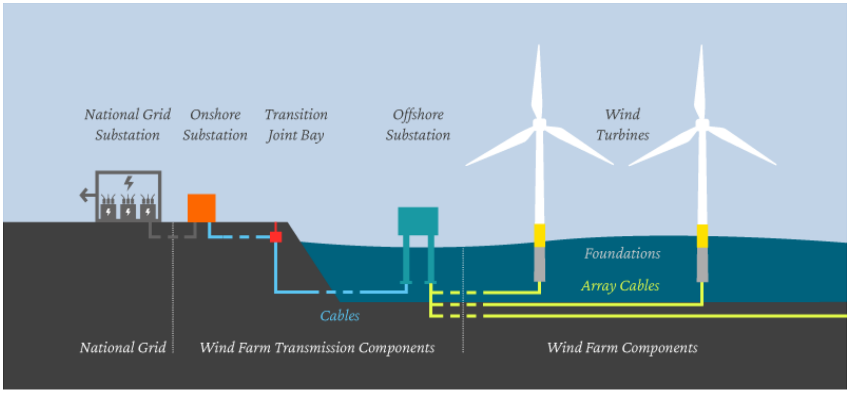


Figure 2.2 Offshore wind farm components. Adapted from [15].

2.1.2 OWF Costs and Financing

When dealing with the economics of a project, one commonly used parameter is the Levelized Cost of Electricity (LCOE), which provides a simple way to compare the cost per unit of energy. The LCOE of renewable energy varies by technology, country and project, based on the renewable energy resource, capital and operating costs, and the efficiency/performance of the technology [16].

The LCOE is the cost of electricity per unit over the lifetime of the project discounted to a net present value (NPV), and its calculation takes into account the following elements: capital expenditures (CAPEX), operating expenditures (OPEX), financial expenditures (FINEX) and the energy production [17].

Figure 2.3 shows the CAPEX and OPEX based on data and surveys from different project developers, and as it can be seen, there are considerable differences in the values across the board.

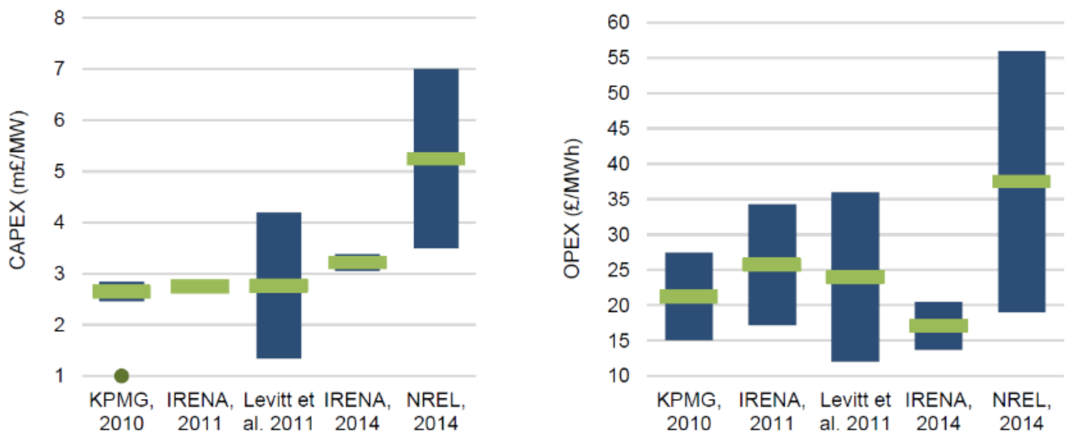


Figure 2.3 Range and average values of capital and operating costs. Adapted from [17].

The numbers shown in the figure above were compiled by the authors in 2018 and converted to British Pounds (2015's value). Nonetheless, with the improvement of technologies and the supply chains necessary for the widespread development of the industry, costs are expected to decrease in the future as shown in Figure 2.4.

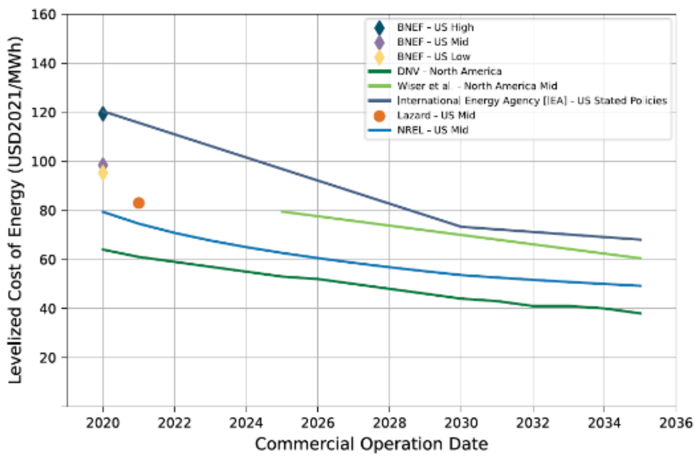


Figure 2.4 LCOE estimates for fixed-bottom offshore wind energy in the USA. Adapted from [18].

The LCOE can be impacted by several factors, for less mature technologies the evolution over time of the LCOE is completely different from well established markets as Figure 2.5 shows.

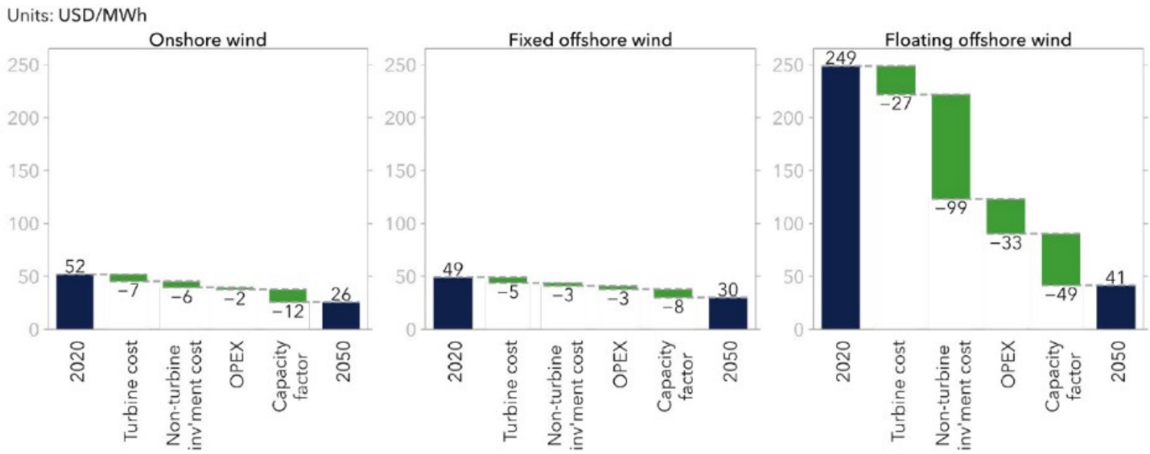


Figure 2.5 Drivers of change for the global average levelized cost of wind. Adapted from [2].

Emerging technologies such as floating offshore wind farms will see pronounced reduction in costs before 2050, mainly due to the establishment of proper supply chains and the economy of scale. Furthermore, for both onshore and fixed offshore wind projects, the main cost reduction is linked to the increase of the capacity factor, which measures how often an equipment/facility runs at nominal power. In other words, as technology evolves, projects will be better designed and operated, leading to better power output and less down time.

Aside of those main cost components, namely; CAPEX, OPEX, FINEX and energy production, it is also important to know how expenditure is distributed in the different stages of a project development. In [17], a lifecycle cost/revenue model is developed based on a deterministic analysis, obtaining the following indicative cost breakdown and sensibility analysis.

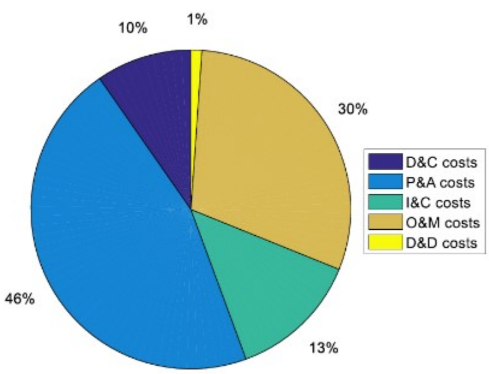


Figure 2.6 Life cycle cost breakdown. Adapted from [17].

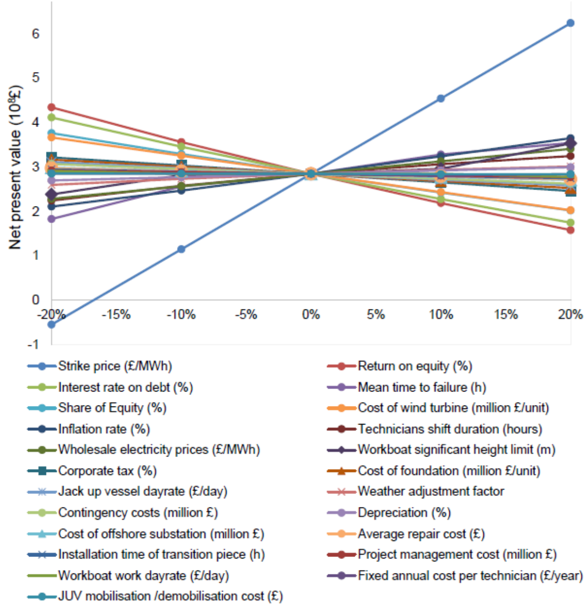


Figure 2.7 Sensitivity analysis of simulation parameters. Adapted from [17].

Regarding the sensibility analysis, one can conclude that the single most impactful parameter for the NPV is the Strike Price of the energy, i.e the selling price of the energy during the lifetime of the project. Hence, for developers and investors it is crucial to have greater certainty on the prices of the energy and consequently, policy makers need to establish clear roadmaps and energy policies. For these reasons, offshore wind tender design should prioritize the two-sided Contract for Difference (2s-CfD) which give price certainty to develop [19].

In Figure 2.6 the project phases are: Development and Consenting (D&C), Production and Acquisition (P&A), Installation and Commissioning (I&C), Operation and Maintenance (O&M) and Decommissioning and Disposal (D&D). As it can be seen, the main costs are related to the P&A phase, followed by O&M, this affirmation is confirmed by [16] and as presented in Figure 2.8, just the turbines themselves represent more than 30% of the total installed cost of a project.

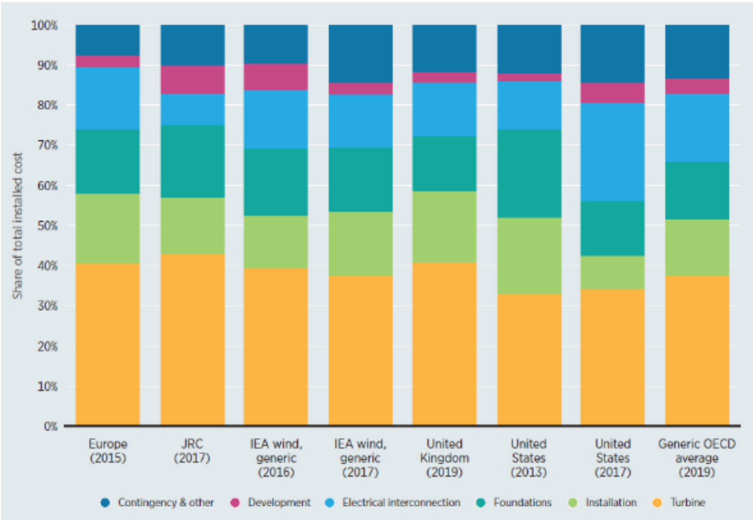


Figure 2.8 Representative offshore wind farm total installed cost breakdowns by country/region, 2013, 2016, 2017. Adapted from [16].

Aside of the cost reduction due to technology improvement and higher production rates, there are other ways of reducing costs, for instance, in [20] a study over ten projects in the North Seas was carried out, concluding that saving between 5-10% was possible when considering a hybrid approach for projects. The hybrid approach in the study refers to developing projects in a multi-country coordinated way, combining the generation and transmission elements. Furthermore, co-location of wave and wind technologies can reduce in great measure the LCOE of projects, this approach is explored in [21] for the P80 hybrid wind-wave concept, designed by the company Floating Power Plant A/S, obtaining a LCOE reduction potential of 32%.

Regarding the financing mechanisms for the development of offshore wind projects, a big portion of them is funded by debt. According to [19] in 2020 nearly 80% of project financing was resourced by debt, moreover, there are two main financing sources for the industry in Europe, debt coming from financial institutions (lower interest rates) and equity from investors (higher interest).

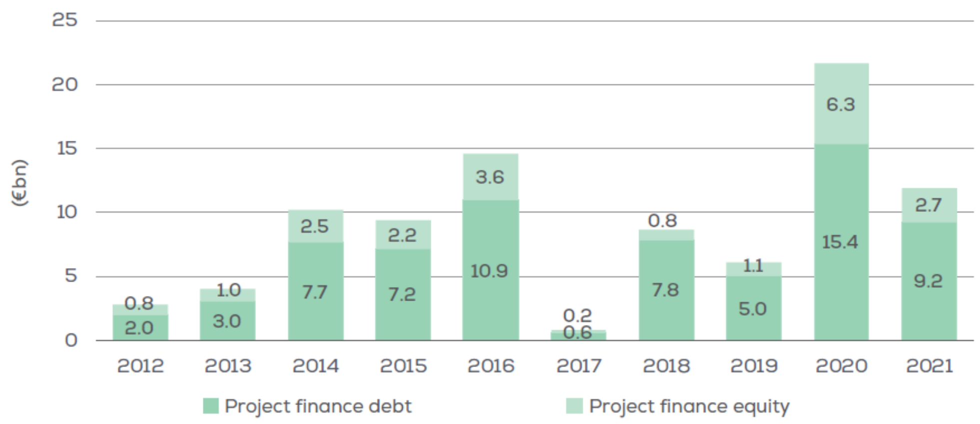


Figure 2.9 Offshore wind project financed debt and equity 2012-2021. Adapted from [22].

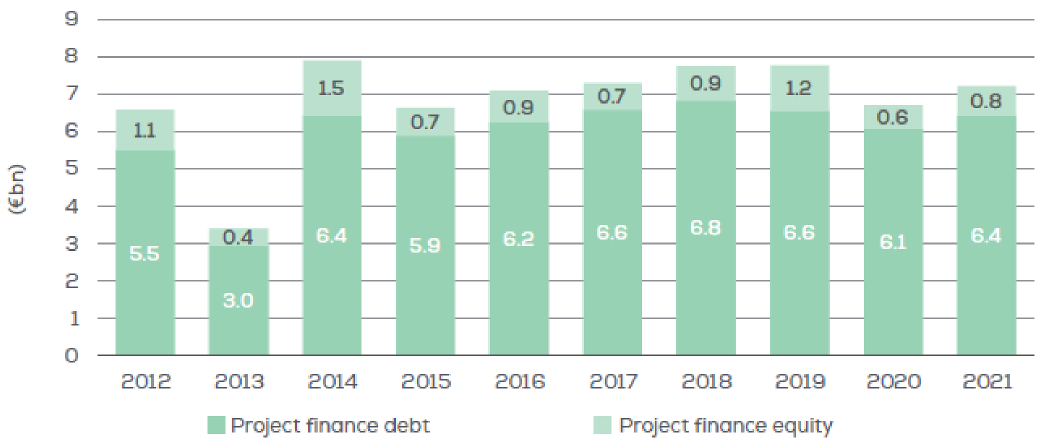


Figure 2.10 Onshore wind project financed debt and equity 2012-2021. Adapted from [22].

The figures above help to show how the maturity of a technology affects the financing schemes, in onshore wind projects the debt ratio average was 87% for the period shown, and for offshore wind projects it was 77%. Mature technologies can access more debt capital (which is cheaper than equity), due to the fact that banks understand and can establish the risks. Therefore, the higher the debt ratio, the lower FINEX [22].

Developers and investors need some degree of certainty when taking final investment decisions. In order to promote the development of large offshore wind projects, governments should opt for tender designs that prioritize the two-sided Contract for Difference (2s-CfD). As it was illustrated previously in Figure 2.7, electricity sell price is the main parameter that affects the NPV of a project, hence, CfD type of contracts give price certainty to developers [19].

2.1.3 Future perspective

The offshore wind market is expected to grow in the next decade, forecasts from BloombergNEF and 4C Offshore estimate that the market will reach 261GW and 286GW by 2031 [18]. As more and more projects are deployed globally, capital expenditures are expected to decrease due to several factors, as Figure 2.11 shows.

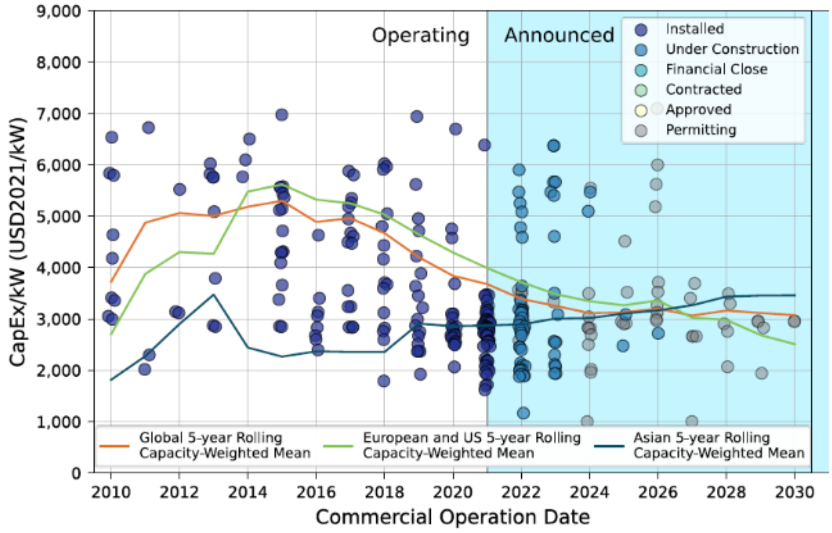


Figure 2.11 Capital expenditures for global offshore wind energy projects. Adapted from [18].

As CAPEX decreases, the FINEX also decrease due to the proportional relation that those capital expenses have. OPEX costs are also expected to decrease in the near future, as wind turbines keep growing in size and capacity, less units are needed for a given name plate capacity of a project. Fewer units imply fewer components [23] and many other innovations would also impact the costs of the projects, as shown in Figure 2.12.

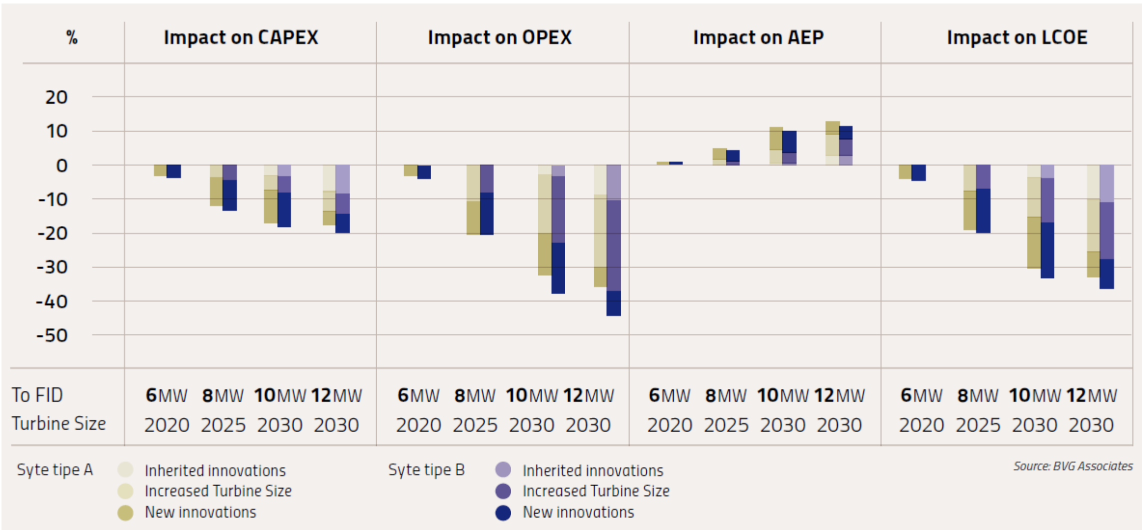


Figure 2.12 Anticipated impact of all innovations by Turbine Size and Site Type over the periods shown (no Other Effects incorporated). Adapted from [24].

As Figure 2.12 summarizes, for a project Site Type A[1], the aggregated impact of all innovations and the change to 12MW-Size Turbines over the period FID 2017-2030 is a 18% reduction in CAPEX, a 36% reduction in OPEX and a 13% increase in annual energy production.

[1] Site Type A: 40km from shore, 25m water depth, 9,0m/s wind speed@100m and 500MW farm size

2.1.4 Costa Rican Context

Even though the country has an extended history of producing electricity from renewable energy, neither the Pacific Ocean nor the Caribbean Sea have been explored as energy sources since recently. The electricity matrix relies mainly on three renewable energy resources as Figure 2.13 shows, and in 2020 it produced 97,94% of its electricity from hydro, geothermal and wind energy.

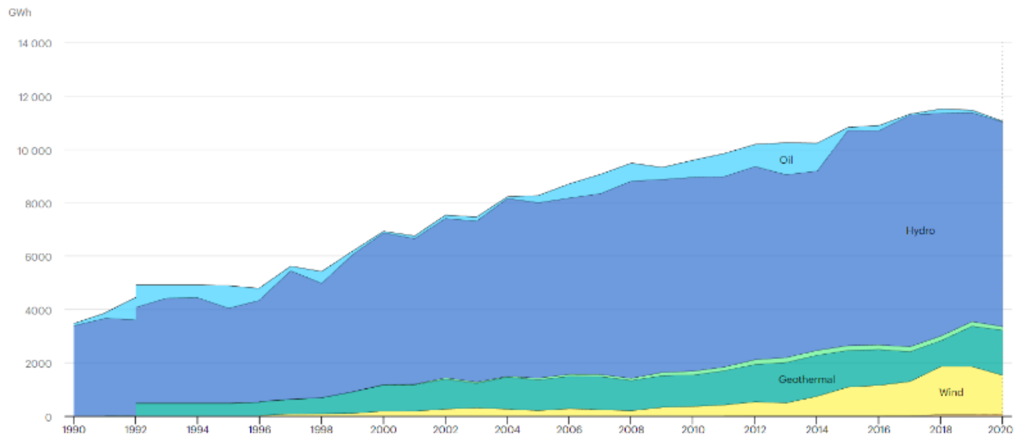


Figure 2.13 Electricity generation by source, Costa Rica 1990-2020. Adapted from [25].

The national electricity generation capacity sits at 3 482.3MW from which 11,2% is wind installations [26]. Moreover, several projections have been made and in all cases, even considering the impact of the COVID-19 pandemic, the electricity demand is expected to increase in the following years as shown in Figure 2.14.

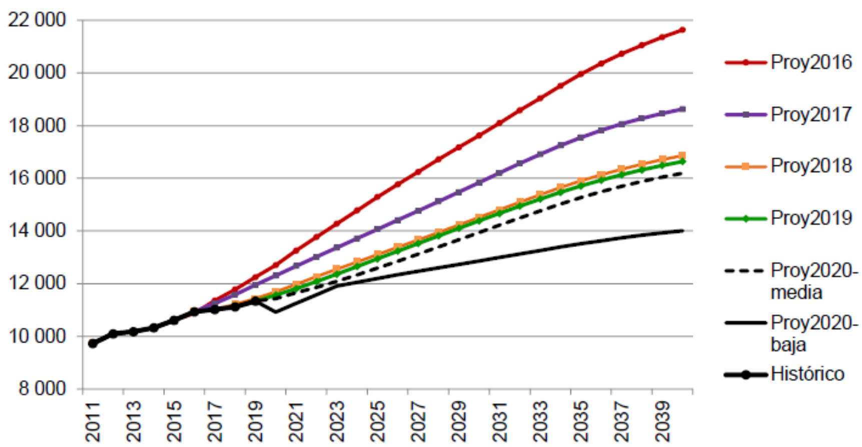


Figure 2.14 Comparison of electricity production historical projections (GWh). Adapted from [27].

This prevision of the increasing electricity demand address only traditional sectors like the industry, residential and public illumination, but those are not the only drivers for a higher demand. The National Decarbonization Plan (NDP) presents a scenario where the transport sector migrates to electrification and use of hydrogen, until the point that it becomes almost independent of fossil fuels by 2050, as shown in Figure 2.15.

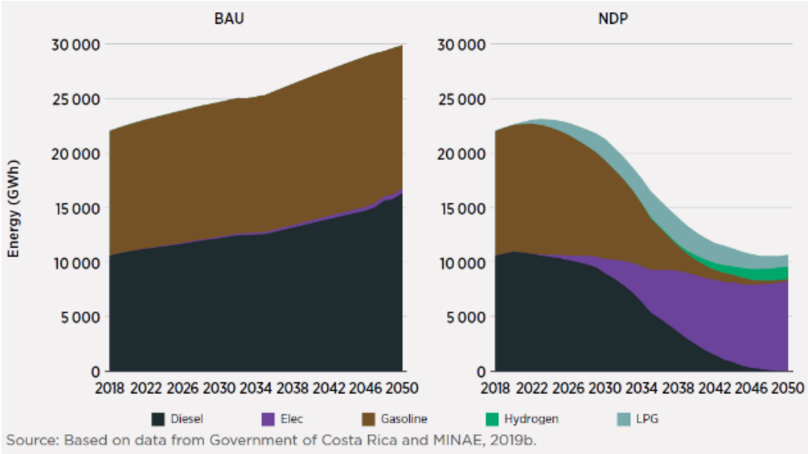


Figure 2.15 Energy mix for transport sector over 2018-2050 at national scale. Adapted from [28].

Thus, in view of the energy projection at national level, it is necessary to keep looking for technical potential to tap into. Moreover, even though there is still technical energy potential inland to be exploited, the offshore potential presents the country with several benefits, for instance, there are less social and space restrictions for offshore developments. Space limitations are of special interest in a small country where 26% of its land is protected areas [29].

With regards to the ocean energy potential of the country, a study was carried out in 2013 to estimate the potential related to waves, tides and oceanic currents. The study concluded that there are technical potentials of 2,0GW for waves, 0,5MW for tide related currents in the main gulfs and 32,2MW for oceanic currents [30]. It was also found that the tidal resource was not enough to be considered, but on the other hand, the offshore wind potential was recommended to be evaluated.

Addressing the offshore wind potential, the World Bank Group-ESMAP estimates that the country has 17GW of technical resource potential, with 1GW of fixed foundation type and 16GW of floating technology [31]. In a study coordinated by the "Instituto Costarricense de Electricidad" (ICE), some 14,40GW of technical potential and 59 058GWh/y of energy were determined. Furthermore, from those 14,40GW, some 4,78GW were located in an area with an estimated capacity factor above 50%, and across 4,64GW of floating and 0,14GW of fixed technologies [32].

The ICE then went forward and carried out an identification study to define a site for the OWF Punta Descartes in the north pacific coast. This study determined that it would be possible to develop a project with a nameplate capacity of 540MW, based on the resource assessment and special restrictions. Nonetheless, considering the limitations of the electrical grid, a 150-200MW capacity is recommended in order to avoid perturbing the stable state of the national network [33].

In line with the identification of the OWF Punta Descartes, an analysis of the supply chain necessary for the development was carried out. In this study a semi-quantitative rating was developed to rate the state of five macro activities related to the evolution of a project, some of the results are summarized in Table 2.1.

Table 2.1 Evaluation of macro activities in the supply chain. [34]

ACTIVITY	RATING
DEVELOPMENT AND MANAGEMENT	3 – Good, requires completion of essential requirements and important activities
TURBINE SUPPLY	3 – Good, requires completion of essential requirements and important activities
BALANCE OF PLANT	3 – Good, requires completion of essential requirements and important activities
INSTALLATION AND COMMISSIONING	1 – Basic, it has only a few enabling conditions and lacks important actions to promote the industry
OPERATION AND MAINTENANCE	1 – Basic, it has only a few enabling conditions and lacks important actions to promote the industry

The study showed that the country has a lot to improve in order to provide a good supply chain for the industry, none of the activities analyzed obtained the highest score of 5, which would classify the activity as "World-class, the enabling conditions are in place to move forward".

Finally, in 2021 in one of the latest activities within the sector, the Global Wind Energy Council (GWEC) carried out a workshop to define the Ocean Energy Pathway for Costa Rica. The workshop focused on knowledge-sharing and market readiness assessment, using an Offshore Wind Market Readiness Assessment (OWMRA) tool, which provided the results shown in Figure 2.16.

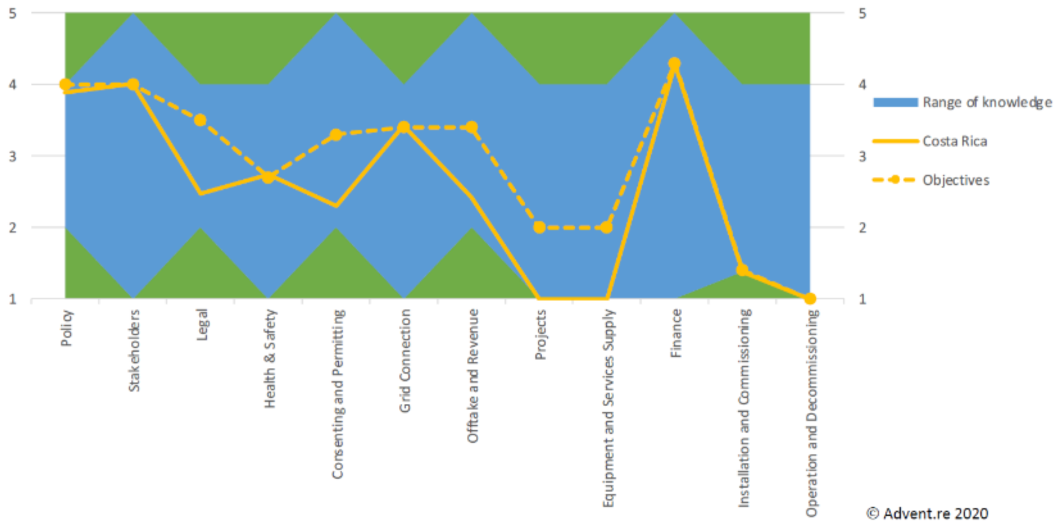


Figure 2.16 River diagram for offshore wind market readiness for Costa Rica. Adapted from [35].

Summarizing the results of the workshop, Costa Rica was found to be strong in terms of Policy, Stakeholders, Grid Connection and Finance, with some improvements to be made on elements specific to offshore wind. Conversely, in subjects like Projects, Equipment & Service Supply, Installation & Commissioning and Operations and Decommissioning, the panorama is less favorable as there are no offshore wind developments in the country.

2.2 Green Hydrogen

There are different categories of hydrogen depending on the production process used, the quality characteristics, contaminants content, etc. On the quality side, there are standards such as ISO 14687:2019 which specifies the minimum quality characteristics of hydrogen fuel as distributed for utilization in vehicular and stationary applications, or the SAE J2719 addressing Hydrogen Fuel Quality for Fuel Cell Vehicles and many others.[1]

Regarding the production process, the most graphical and common classification employs colors to differentiate types. The actual trend is to set apart hydrogen produced from renewable energy sources or that with a reduced carbon footprint. Reduced emissions can be achieved by implementing carbon capture usage and storage (CCUS) systems. Apart from the low emissions hydrogen, the rest of hydrogen production systems are far more harmful for the environment. Figure 2.17 shows a graphical summary of the color code commonly used in the industry.

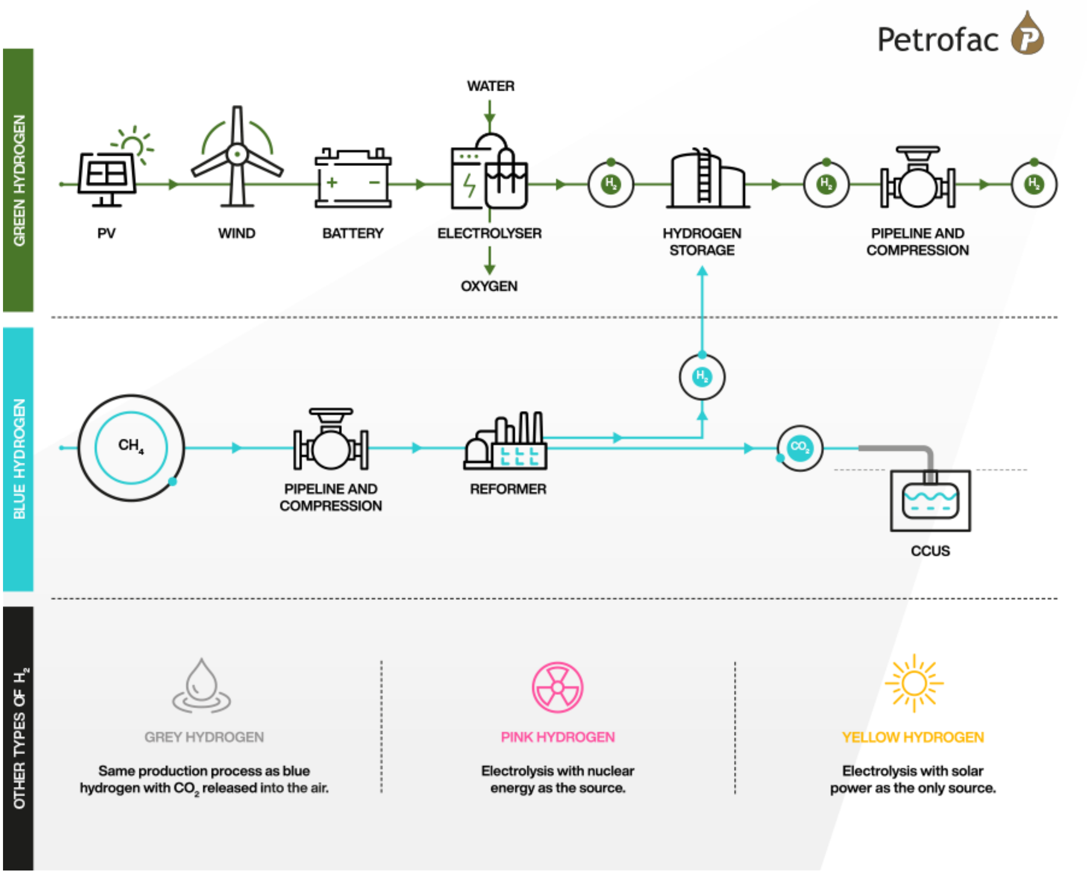


Figure 2.17 Colors of hydrogen. Adapted from [36].

There are different processes that can produce hydrogen and may fit in the color coding depicted above, most of which are presented in Table 2.2. Nevertheless, for green hydrogen production, the most commonly used process is water electrolysis.

[1] Database of standards, available at: https://h2tools.org/fuel-cell-codes-and-standards?search_api_fulltext=

Table 2.2 Various hydrogen production methods; advantages, disadvantages, efficiency and cost [37].

Method	Advantages	Disadvantages	Efficiency (%)	Cost [$/kg]
Steam Reforming	Developed technology & Existing infrastructure	Produces CO, CO_2, Unstable supply	74–85	2,27
Partial Oxidation	Established technology	Along with H_2 Production, produces heavy oils and petroleum coke	60–75	1,48
Auto thermal Reforming	Well established technology & Existing infrastructure	Produces CO_2 as a by-product, use of fossil fuels.	60–75	1,48
Bio photolysis	Consumes CO_2, produces O_2 as a by-product, works under mild conditions.	Low yields of H_2, sunlight needed, large reactor required, O_2 sensitivity, high cost of material.	10–11	2,13
Dark Fermentation	Simple method, H_2 produced without light, no limitation O_2, CO_2-neutral, involves waste recycling	Fatty acids elimination, low yields of H_2, low efficiency, necessity of huge volume of reactor	60–80	2,57
Photo Fermentation	Involves waste water recycling, uses different organic waste waters, CO_2-neutral.	Low efficiency, low H_2 production rate, sunlight required, necessity of huge volume of reactor, O_2-sensitivity	0.1	2,83
Gasification	Abundant, cheap feedstock and neutral CO_2.	Fluctuating H_2 yields because of feedstock impurities, seasonal availability and formation of tar.	30–40	1,77–2,05
Pyrolysis	Abundant, cheap feedstock and CO_2-neutral.	Tar formation, fluctuating H_2 amount because of feedstock impurities and seasonal availability	35–50	1,59–1,70
Thermolysis	Clean and sustainable, O_2-byproduct, copious feedstock	High capital costs, elements toxicity, corrosion problems.	20–45	7,98–8,40
Photolysis	O_2 as by-product, abundant feedstock, no emissions.	Low efficiency, non-effective photocatalytic material, requires sunlight.	0.06	8–10
Electrolysis	Established technology, zero emissions, existing infrastructure O_2 as by-product	Storage and Transportation problem.	60–80	10,30

Some authors are of the opinion that is important to stress out that hydrogen is not an energy resource and has to be addressed as what it actually is, an energy vector. Hydrogen is seen as a necessary game changer in the decarbonization race because it is a more suitable energy storage medium than other fuels, manly thanks to its high heat value (HHV). In numbers, the energy density of hydrogen is 140 MJ/kg (more than twice that of typical solid fuels 50 MJ/kg) [38].

In a global economy where many products can be traded across the world, renewable energy did not have a viable way of being exported until now. Using hydrogen as an energy carrier could fill the gap, enabling renewable energy to be traded in the form of molecules or commodities, such as liquefied/pressurized hydrogen, ammonia, etc. However, there are several restrictions to green hydrogen international trade, some of them are [39]:

- Potential is distributed unevenly across countries.
- Low-cost supply locations can be in remote places with limited infrastructure.
- Additional transport cost to the importing markets may reduce attractiveness.

2.2.1 General overview

There is a huge potential for green hydrogen worldwide, production at costs lower than 2 $/kg_{H2}$ is about 10.000 EJ/ year by 2050 (24 times the global final energy demand in 2020) [39]. These estimates suggest that green hydrogen may compete with fossil-derived types sooner than expected, mainly in locations with good renewable energy resources. Therefore, most of the growth in global hydrogen demand may well not be derived from SMR[1] deployments [40].

Low emissions hydrogen was less than 1 million tons (Mt) in 2021, practically all of it using CCUS. In a scenario where all planned projects are completed, by 2030 the production could reach 16-24 Mt per year, with 9-14 Mt of it being green hydrogen and 7-10 Mt of blue hydrogen. Nevertheless, meeting climate goals would require 34 Mt of low-emission hydrogen per year by 2030 [5].

In line with the previous statistics, global deployment of renewable capacity dedicated to hydrogen production is expected to grow exponentially by 2050. The potential for green hydrogen is linked to solar and wind potential, which exceeds global energy demand by far; today and in any future scenario [41].

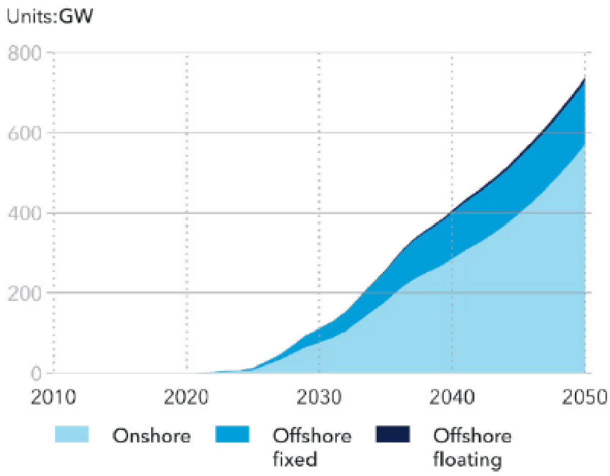


Figure 2.18 Global wind capacity dedicated to hydrogen production. Adapted from [2].

Dedicated wind capacity alone is projected to reach more than 700GW (see Figure 2.18), with a heavy portion of it being installed onshore (about 580GW), the rest being offshore fixed wind projects and a minor fraction of offshore floating wind developments.

With the current technological race, new advances in electrolyzer technologies reach the market at a staggering pace. For instance, McPhy offers an alkaline large scale platform up to 100MW, based on a modular setup of their McLyzer 800-30 electrolyzer, with a DC energy consumption of 4,5kWh/Nm^3 @ 30barg (about 50 kWh/kg_{H2}) [42].

Moreover, in Europe the largest project to date is planned to take place in Spain, the HyDeal project, which is scheduled to start in 2025. HyDeal will count with a total electrolyzers capacity of 7,4GW, powered by 9,5GW of solar power [43].

[1] Steam Methane Reforming

In the Dutch part of the North Sea, Neptune Energy and the German company RWE collaborate to develop a project with and electrolyzer capacity of 300 to 500 MW by 2030 [44]. Then, Tree Energy Solutions (TES) and German utility EWE have signed a Memorandum of Understanding to build an electrolyzer, with an initial planned capacity of 500 MW and one more unit planned to reach a total capacity of 1GW [45]. Some other significant projects are presented in Table 2.3.

Table 2.3 Green hydrogen projects pipeline [46]

Project	Capacity (GW)
HyDeal	67
Reckaz	30
Western Green Energy Hub	28
Asian Renewable Energy Hub	14
Aman	16-20
Gren Energy Oman	14
NortH2	>10
AquaVentus	10

Furthermore, some projects will investigate how to combine an efficient electrolyzers with offshore wind energy. The H2RES project for instance, will have a capacity of 2 MW of electrolyzer and 7,2 MW of offshore wind turbines, and its meant to produce up to around 1 ton of renewable hydrogen a day [47].

Yara and Ørsted have partnered to develop a 100 MW wind powered electrolyzer plant, aiming to replace fossil-based hydrogen with green hydrogen for ammonia production. This project could generate about 75.000 tons of green ammonia per year and could be operational in 2024/2025 [48].

As explained earlier, even though there are several processes to produce hydrogen in the industry, water electrolysis is seen as the chosen one for the decarbonization goals. However, with efficiencies ranging from 60% to 80% (see Table 2.2) electrolysis seems less of an option against steam methane reforming, but the latter produces CO2 emissions and electrolysis does not.

Hence, research has been carried out to improve the general efficiency of using hydrogen as an energy vector. For instance, in the round trip of a electricity-H2-electricity system (to store surplus electricity as hydrogen), promising methods include oxygen recuperation from the electrolyzer and use it as the oxidant in the fuel cell instead of compressed air. One study found the round-trip system efficiency to be 18% with oxygen recuperation and 13.5% without it [49].

Within the electrolysis field, three predominant categories are found. Based on its operating conditions, the electrolyte and the ionic agent present (OH^-, H+, $O2^-$) the main technologies are: alkaline electrolysis (ALK), proton-exchange membrane electrolysis (PEM), and solid oxide electrolysis (SOE) [50]. Table 2.4 presents a summary of the main characteristics of the dominant systems, i.e., alkaline and proton exchange membrane technologies.

Table 2.4 Electrolyzer technologies main characteristics.

	C | F [a]	PEM	ALK	REF
STACK LEVEL				
Temperature (°C)	< 2021	20-100	40-90	[50]
Cell Pressure (bar)	2022 | 2030 2020 | 2050 < 2021	<40 | <70 <30 | >70 <200	Atm. <30 | >70 <30	[43] [41] [50]
Voltage efficiency (LHV)	2020 | 2050 < 2021 2017 | 2025	50-68% | >80%210 46-60% 57 | 64%	50-68% | >70% 51-60% 65 | 68%	[41] [50] [51]
Electrical efficiency (kWh/kg_{H2})	2020 | 2050 2022	47-66 | < 42 50,07	47-66 | < 42 42,28-48,95	[41] [52]
Stack Lifetime (kh)	2020 | 2030 2022 | 2030 2020 | 2050 < 2021 2017 | 2025	50,5-67,5 | 66,1-85,0 50 | >80 50-80 | 100-120 60-100 40 | 50	85,0-94,4 | 62,3-82,5 80 | 100 60 | 100 60-120 65 | 68	[53] [43] [41] [50] [51]
Degradation (%/y)	2020 | 2030 < 2021	0,19 | 0,12 [d] 0,50-2,50	0,12 | 0,10 [d] 0,25-1,50	[43] [50]
CAPEX (Currency/kW)	2020 | 2050 2017 | 2025	$400 | <100 €420 | 210	$270 | <100 €340 | 215	[41] [51]
SYSTEM LEVEL				
Electrical efficiency 10 (kWh/kg_{H2})	2022 | 2030 2020 | 2030 2020 | 2050 2017 | 2025 < 2021	53,40 | 50,07 [b] 55 | 50 50-83 | < 45 58 | 52 60,08 [b]	52,29 | 47,84 [b] 50 | 48 50-78 | < 45 51 | 49 61,75 [b]	[43] [54] [41] [51] [50]
Cold start (to nominal load)	2020 | 2050	<20 | <5min	< 50 | <30min	[41]
CAPEX (Currency/kW)	2020 | 2030 2020 | 2030 2020 | 2050 < 2021 2017 | 2025	€1.225-867 | 1.038-604 €900 | 500 $700-1400 | <200 €1.300-2.140 €1.200 | 700	€988-712 | 750-500 €600 | 400 $500-1.000 | <200 €740-1.390 €750 | 480	[53] [43] [41] [50] [51]
OPEX (%CAPEX/y)	2020 | 2030 < 2021 2017 | 2025	2,05 | 2,10 [c] 3-5 2 | 2	2,08 | 2,00 [c] 2-3 2 | 2	[43] [50] [51]
MISCELLANEOUS				
Advantages	< 2021	Highest purity; compact design; high production rate	Low capital cost; cheap catalysts; high durability; stable operation	[50]
Disadvantages	< 2021	High cost of rare components; acidic environment; high pressure	Corrosive system; lowest purity; high energy consumption	[50]
Commercial status	2022 < 2021	Available Near commercial	Available Commercial	[43] [50]

a. C | F: Current values | Forecasted values.
b. A conversion factor of 0,08988 kg_{H2}/Nm^3 was applied [55].
c. Calculated from the available data.
d. Degradation given as %/1.000h

2.2.2 Green hydrogen costs

Addressing the LCOH, the main component is the price of the electricity used, by far. In some cases, it accounts for around 55% of the total hydrogen production costs [5]. Even though costs have been falling, in 2020 green hydrogen was still 2-3 times more expensive than blue hydrogen [41].

As regards of green hydrogen production pathways, the challenge is mainly to provide a reliable and low cost fuel [54]. If significant efforts are made to reduce electricity costs and an aggressive electrolyzer deployment is seen, those factors can make green hydrogen cheaper than any low-carbon alternative (*i.e.* < USD 1/kg), before 2040 [41].

Figure 2.19 shows the LCOH for different regions and the portions that correspond to the electricity and the electrolyzer for optimistic and pessimistic scenarios by 2050.

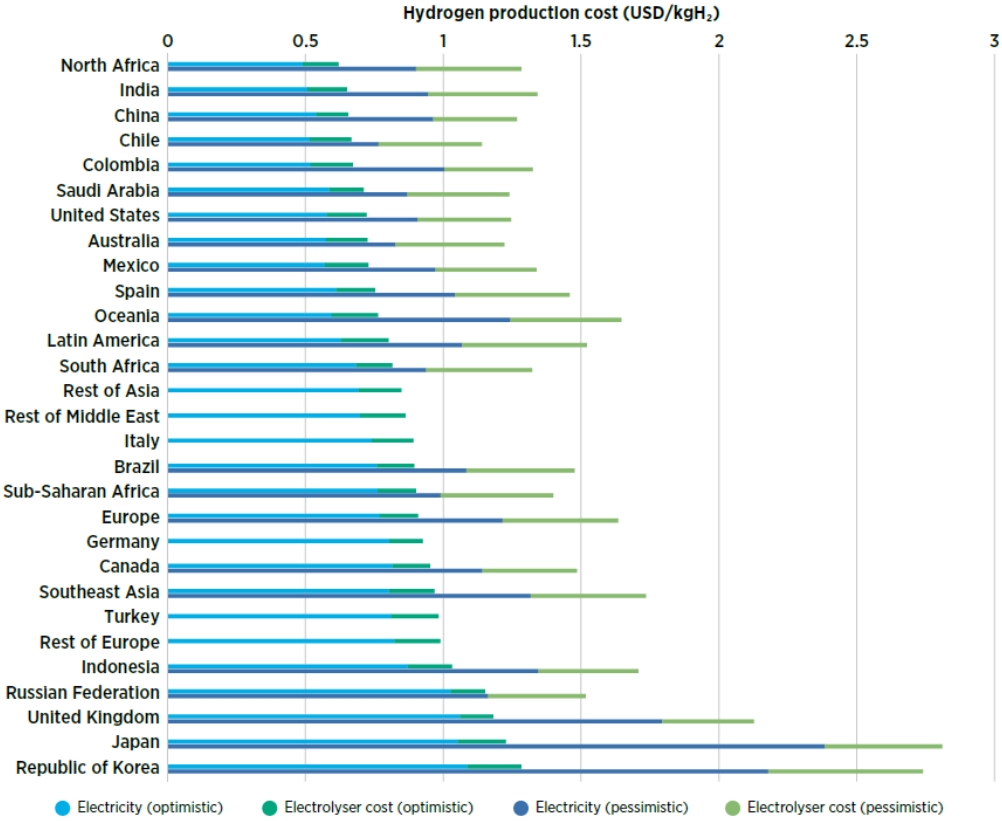


Figure 2.19 LCOH by region in 2050 for an optimistic and pessimistic scenario. Adapted from [39].

Some of the countries on the lower end of cost range are countries with good solar resource, wind or a combination of both. Africa for instance, is home to 60% of the best solar resources globally [56].

Forecasts for the mid and long term cost of green hydrogen show that it will compete with fossil fuels. Figure 2.20 shows the prices range for different technologies in the Net Zero Emissions scenario in 2050, which is in line with the values shown in Figure 2.19. In this scenario, in all low emissions categories of hydrogen, prices reach levels well below 2 USD/kg$_{H2}$.

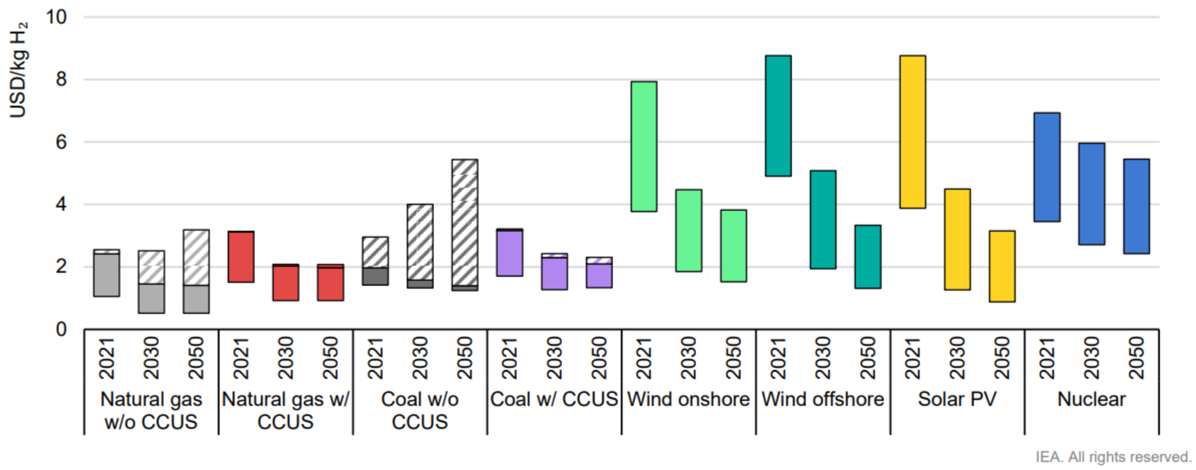


Figure 2.20 LCOH production by technology in 2021 and in the Net Zero Emissions by 2050 Scenario, 2030 and 2050. Adapted from [5].

Although electrolyzer investment costs shown in Figure 2.19 seem a minor part in the LCOH, it does play a main role when developing a project. Estimations made in 2017 for the future investment costs of ALK plants, narrowed down values to the 787-906 $EUR_{2017}/kW_{HHV\text{-}Output}$ range [57]. As for PEM electrolyzers, the future investment costs for the year 2030 stretch from 397 to 955 $EUR_{2017}/kW_{HHV\text{-}Output}$, as shown in Figure 2.21.

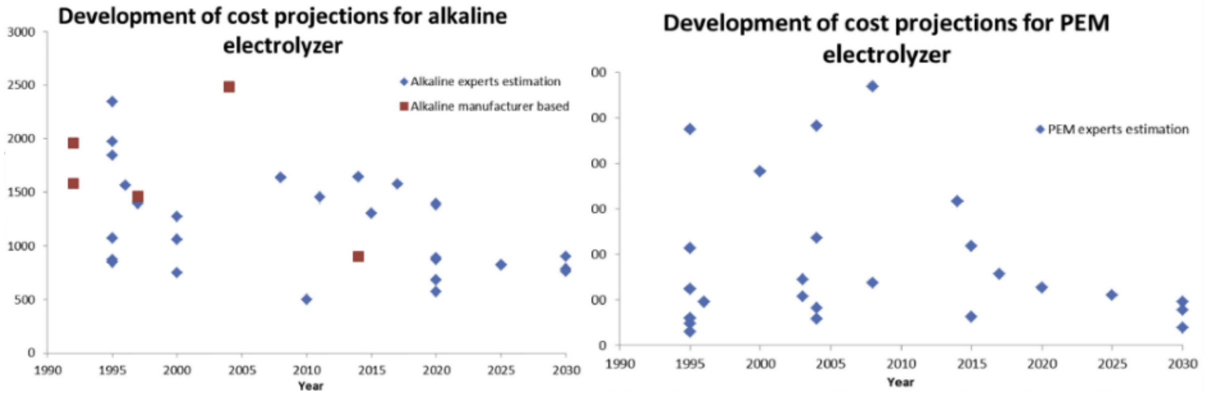


Figure 2.21 Development of expected ALK and PEM electrolysis plant cost in EUR_{2017}/kW HHV-Output. Adapted from [57].

According to IRENA [41], some examples of key strategies to reduce investment costs for electrolysis plants are:

- Increasing plant size from 1 MW to 20 MW could reduce costs by over a third.
- Increasing stack production to automated production in GW scale.
- Reduce the use of scarce materials.

Technological learning would have significant impacts on cost reduction by 2050, the strategies aforementioned and many other technological advances could bring costs down to a third in the case of PEM technology and around 50% for ALK systems. Additionally, SOE technology is projected to be competitive and even undercut ALK cells based on a cost to hydrogen output rating as shown in Figure 2.21.

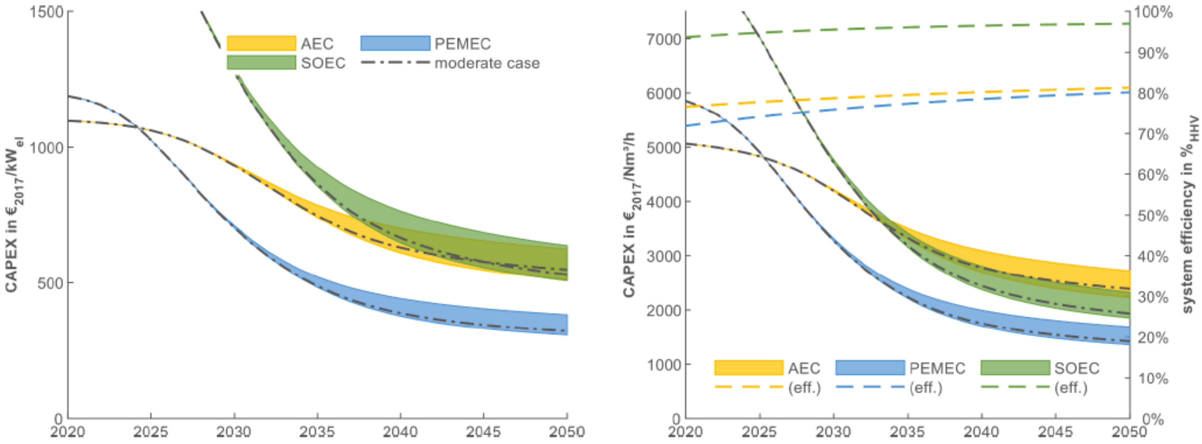


Figure 2.22 Estimated ranges for technological learning of electrolysis related to the defined deployment scenarios (left. based on electric power; right. based on hydrogen. Adapted from [58]

Not only whole new technologies such as SOE are growing in presence and importance, but also researchers are achieving improvements on a fast pace for the well-established technologies. For instance, a newly developed alkaline capillary-fed electrolysis cell demonstrated performance exceeding commercial electrolysis cells (see Figure 2.23). With a cell voltage of only 1.51 V (at 0,5 A cm^{-2} and 85 °C), reaching 98% energy efficiency, with an energy consumption of 40,4 kWh/kg_{H2} [59].

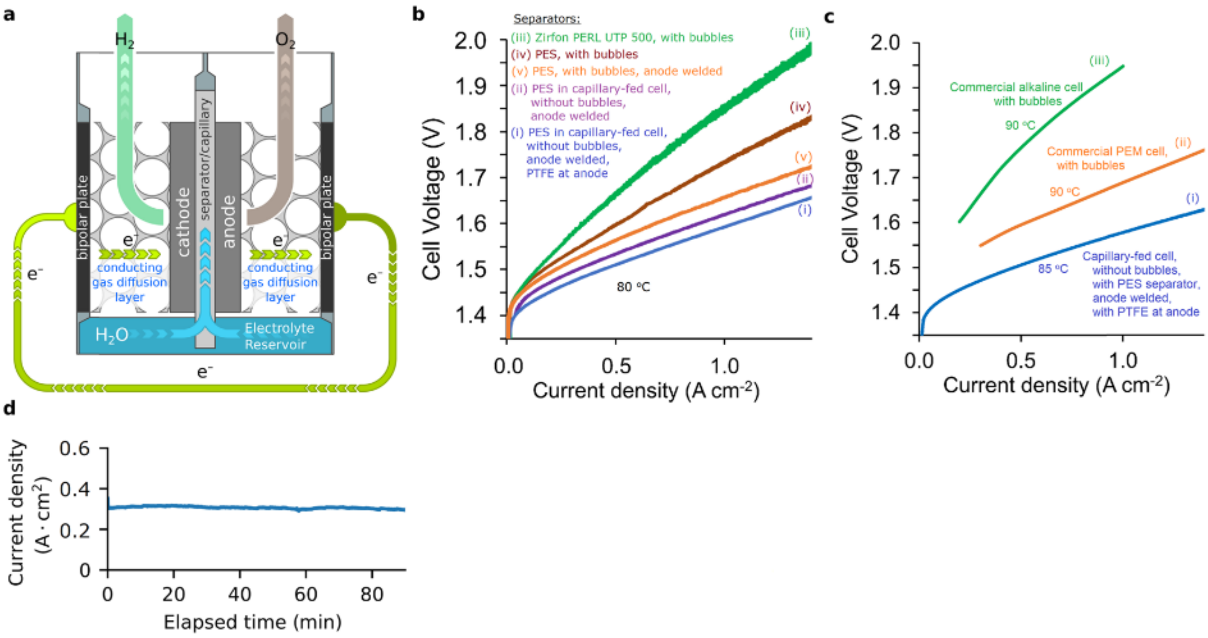


Figure 2.23 Capillary-fed electrolysis cell. Adapted from [59].

Moving towards in detail cost segregation, an electrolyzer system; say a PEM system, is composed by two main cost segments: the stack and the balance of plant. The former one represents 45% of the cost and the latter 55%. An interesting fact that can be extracted from Figure 2.24 is that rare materials represent only a 4,1% of the total cost of a PEM system (with 1,4% due to Iridium and 2,7% to Paladium).

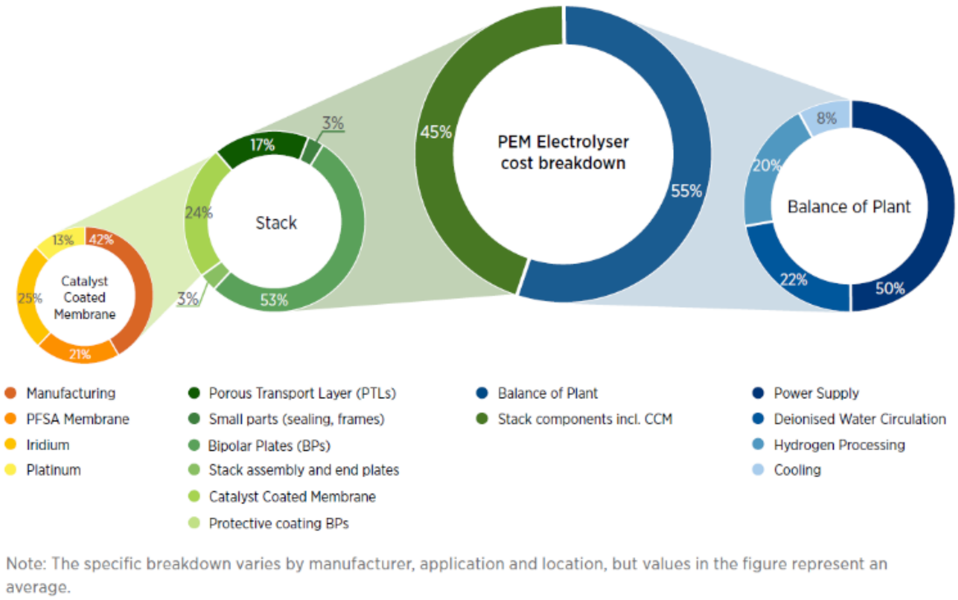


Figure 2.24 Cost breakdown for a 1 MW PEM electrolyzer, moving from full system, to stack, to CCM[1]. Adapted from [41].

Another call to attention from the cost breakdown shown above has to do with the balance of plant. The importance of optimizing all ancillary systems is as important as any improvement on the stack side. For instance, 1% cost reduction on the power supply section represents an overall 0,55% reduction, while the same 1% reduction on the CCM accounts only for an overall 0,11% reduction.

2.2.3 Costa Rican Context

In 2021 the company HINICIO elaborated a study about the Global Hydrogen Market and the possible participation of Costa Rica in it [60], some of the mayor findings are:

- By 2050 the potential hydrogen production is estimated at 5.927ktonH_2 per year, around 8.5% of global demand in 2020.
- The lowest LCOH corresponds to hydrogen produced from onshore wind energy (1,24\$/kgH_2), but it only represents 9,8% of the expected national production by 2050.
- Green hydrogen produced from the other renewable resources will cost: 1,68 \$/kgH_2 from PV, 5,1 \$/kgH_2 from geothermal, and 3,4 \$/kgH_2 in the 1,5°C scenario.
- Hydrogen production from the reported electricity surplus in 2019 could be around 5,3ktonH_2 per year, while with the excess from 2020 it would reach 12,6ktonH_2.
- In the 1,5°C scenario, demand from seven industrial sectors (Industrial Supplies, Industrial Heat, Mobility, Fuels Supplement, Energy Storage, Forklifts and Synthetic Fuels) could reach 32ktonH_2 by 2030, for which some 1.215GWh of renewable electricity and 377MW of electrolyzers would be necessary. By 2050, demand will be 611ktonH_2, requiring 12.582GWh of electricity and 7.119MW of electrolyzers.
- In the high demand scenario (limiting global warming to 1,5°C), the green hydrogen potential is 10 times higher than the national demand.[60]

[1] Catalyst Coated Membrane

As it was mentioned in Section 1.1, more than 60% of the final energy demand in Costa Rica comes from the transportation sector. In the HB Scenario, a scenario with high penetration of fuel cell electric vehicles, demand of hydrogen will triple that of the business as usual scenario (BAU Scenario) [61], as Figure 2.25 shows.

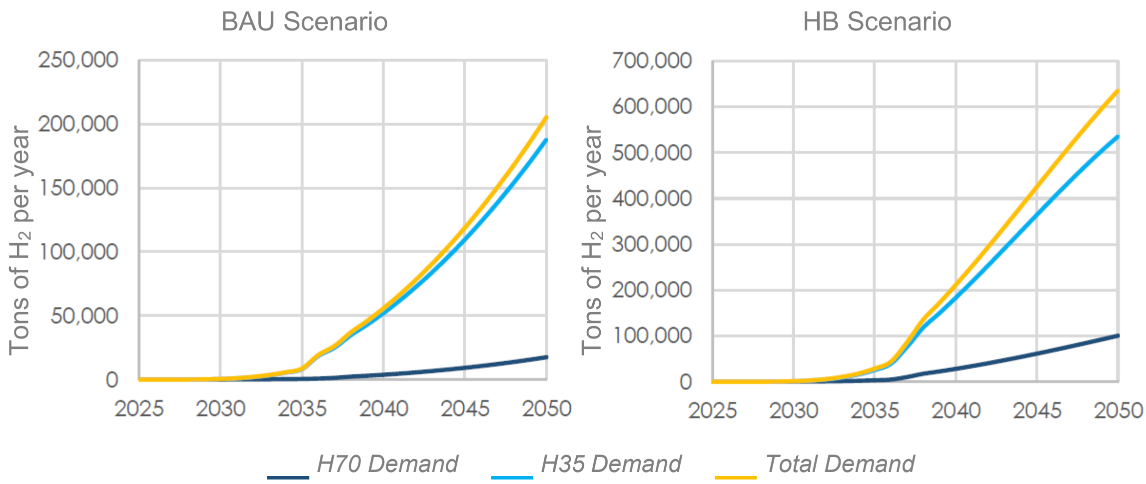


Figure 2.25 Hydrogen demand in Costa Rica in BAU and HB scenarios, adapted from. Adapted from [61].

It is noteworthy to mention that hydrogen is not a new thing in Costa Rica, the national refinery RECOPE[1] was pioneer in studying the use of H_2 in its business. They carried out a research project that evolved in a way that it led to the construction of a demonstration plant for hydrogen production.

Due to restriction in the national legislation, RECOPE ended up authorizing Ad Astra Rocket company to operate the demonstration plant, which runs on solar PV and wind energies (see Figure 2.26). By 2014, producing 1 kg of hydrogen costed between 13.000 to 14.000 colones (CRC), around 24,21-26,07 USD_{2014}/kgH_2. Afterwards, the ICE ventured with studies to evaluate the use hydrogen as a substitute of fossil fuels for electricity generation. However, the results indicated that the necessary conditions for a successful venture were not met [62].

Figure 2.26 Ad Astra Rocket Company facilities[2].

[1] From the Spanish name "Refinadora Costarricense de Petroleo"
[2] From https://www.adastrarocket.com/

Moving forward, several other milestones have been achieved. In 2013, a team of engineers and technicians from Ad Astra Rocket Company and Cummins Power Generation, successfully powered a Cummins-built electrical generator using mixtures of hydrogen and biogas [63]. Later in 2014, Ad Astra and RECOPE signed an agreement for US$400.000 to start the next cooperation phase to develop the hydrogen industry [64].

In 2018 the newly formed Hydrogen Commission published an inter-institutional action plan to promote the use of hydrogen in the transport sector. Other organizations have been founded around the hydrogen industry in Costa Rica, the ACH [1] is an example of a non for profit body. Then, in a technical cooperation with the Inter-American Development Bank (BID) the "Alianza por el hidrógeno" is created.

The first commercial use of hydrogen cars in Central America took place in the North Pacific coast of Costa Rica. The vocation rentals complex Las Catalinas partnered with Ad Astra, Purdy Motor, and Toyota to deploy a mobility service using Toyotas MIRAI [65]. Then, in a major step, Ad Astra Rocket Company and Latin America's asset management Mesoamerica, joined forces in 2022 to form ProNova Energy, a joint venture dedicated to developing green hydrogen solutions [66].

On the public policies side, documents such as the National Development Plan (PND_2015-2018), the VII National Energy Plan (PNE_2015-2030), and the National Strategy on Climate Change (ENCC[2]) have paved the way for the creation of the National Strategy for Green H_2 of Costa Rica, condensed in [67].

The political stability, the aforementioned policies in combination with other macroeconomic and geopolitical factors, have attracted the attention of big companies in the field of green hydrogen. Global Infrastructure & Industrial Project Solutions company Kadelco for instance, plans to install an industrial facility capable of producing 50ktonH_2 per year [68].

2.2.4 Seawater hydrogen production

As eyes turn to the seeking for renewable energy resources, and due to the variability of some of those resources (i.e. offshore wind, floating photovoltaics, etc.) hydrogen will play a role as one of the preferred energy carriers.

Some challenges have been identified long ago, Williams [69] explains that there are two options: total desalinization to produce essentially distilled water and to design electrolyzer systems capable of utilizing natural sea water. The broad advantages and disadvantages of both approaches are presented in Table 2.5.

[1] Acronym in Spanish for "Asociación Costarricense de Hidrógeno"
[2] Acronym in Spanish for "Estrategia Nacional de Cambio Climático"

Table 2.5 Seawater electrolysis approaches.

	Desalinization	**Direct Electrolysis**
Advantages	Use of conventional and well-developed electrolysis cells.	• Possible lower capital costs • Natural elimination of the waste brine. • May allow recovering of metals present in sea water, such as silver, gold, mercury, and copper.
Disadvantages	• Capital costs of the water purification equipment. • Environmental problems when disposing residual salts removed during desalinization.	• Probable corrosion and contamination problems • Undesirable electrochemical products such as chlorine.

Certainly, some time has passed since the aforementioned features of seawater electrolysis were stated. Nowadays, costs of reverse osmosis (RO) of seawater are estimated at around 1,00 $\$/m^3$ of water (less than 0.5% of the total cost). Additionally, energy requirements for desalination correspond to less than 0,1% of electrolyzer's energy consumption (desalination by RO requires 3-6 kWh/m^3 of water) [5]. Michelle K et al [70] collated a cost database of 300+ desalination plants and found that current large-scale desalination plants are capable of producing water in the range of $\$0,50$–$\$2,00/m^3$.

Then, new technologies have proven to be more resilient to marine conditions. In a study on high-temperature electrolysis of synthetic seawater, researchers found similar electrochemical performance when using steam produced from pure water and seawater and SOE technology. Short-term degradation rates are similar. Regarding direct sea salt contamination in an SOE's fuel electrode, contaminated cells exhibit rather similar performance to uncontaminated ones [71].

Another study analyzed the efficiency and stability of SOE and at constant current density of 200 mA/cm^2 for 420h. Results obtained include a 183 mL/min of hydrogen production, degradation rate of 4,0%, energy efficiency of 72,47%. The study concluded that after 420h of experiment, the long-term operation had no obvious effect on the cell itself [72].

Moving towards the system scale and addressing the role of hydrogen as energy storage for offshore platforms, a thorough study analyzed eleven Energy Storage Systems (EES) was carried out. By using eleven different Key Performance Indicators (KPIs) researchers found that a combination of Li-ion batteries and Compressed Air Energy Storage (CAES), hold the most promising performance to meet partial energy demands in the near future [73].

Although, in the long term, the similarity among technologies prevents any judgment, a hybrid storage system could prove helpful to meet all load requirements of an offshore platform. An example of such system is shown in Figure 2.27. In principle, this hybrid system would rely on batteries for short-term, rapid load supply and on hydrogen for seasonal variations [73].

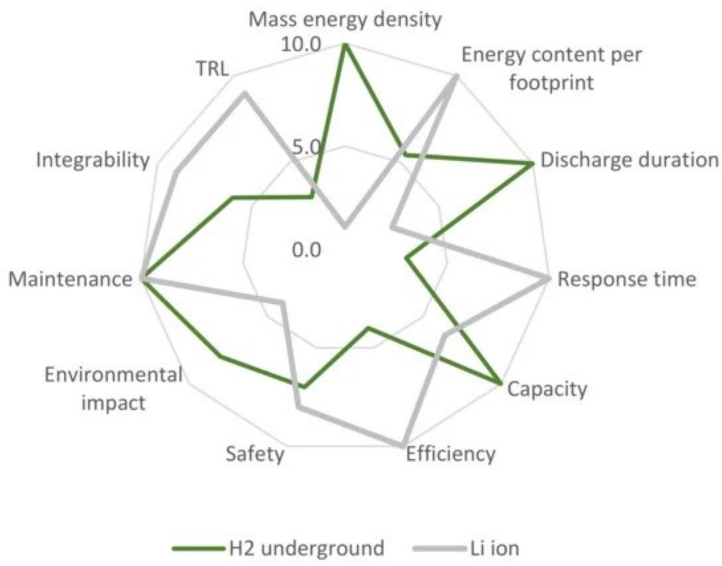


Figure 2.27 Spider chart of a hybrid battery–hydrogen system performance for different KPIs. Adapted from [73].

Water and electricity are necessary to produce hydrogen by electrolysis (besides the electrolyzer itself). Thus, water access cost has to be taken into account in any project. In the case of seawater usage, desalination costs come into scene.

Another application for seawater hydrogen is ammonia production. Ammonia is well known internationally traded good, and recommendations from the International Renewable Energy Agency (IRENA) dictate that water security should not be compromised when producing it. Hence, desalinated sea water should be used for GW-scale ammonia plants in most locations.

In a near future, more developments are expected to deal with the challenges that seawater electrolysis poses, as green hydrogen demand is and will be growing significantly in order to decarbonize the economy.

CHAPTER 3

Punta Descartes OWF

This chapter summarizes the main characteristics of the OWF Punta Descartes from the identification study carried out in [33]. The goal of the chapter is to set the base for the techno-economic analysis of hydrogen production to be developed in chapter 4.

3.1 Location

OWF Punta Descartes is located in the north pacific coast of Costa Rica, within the area defined in [32] as the highest potential area for the development of offshore wind projects. The area in the study comprehends depths ranging from <50-70m and extends from 3-10km from the coast as shown below.

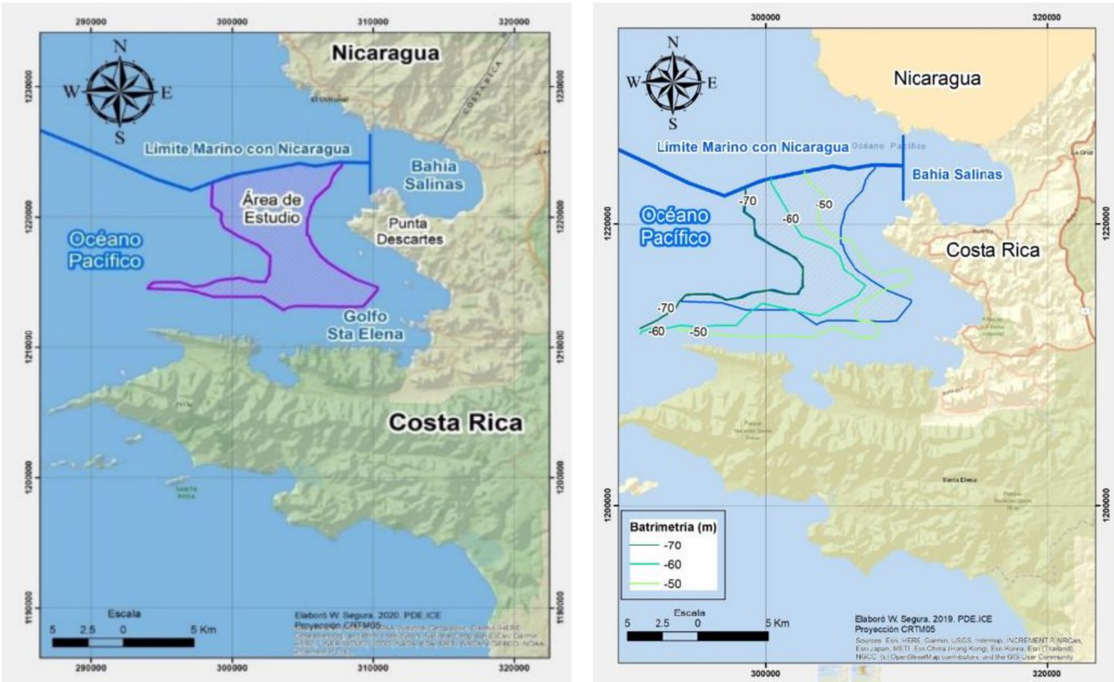


Figure 3.1 Extension and bathymetry of projects' area. Adapted from [33].

3.2 Layout and Energy Production

The OWF Punta Descartes is currently in the identification phase, for which several assumptions were made, with the nameplate capacity of the wind turbines (10MW) being in the main ones. As result, and taking into account the available bathymetric data, 54 turbines (540MW) are considered in the modelling of the wind farm, then, two layouts are proposed as shown in Figure 3.2.

Figure 3.2 Wind turbine layout options (A in yellow, B in cyan). Adapted from [33]

For layout option A, the main criterion is the alignment of the wind turbines to face the predominant wind direction, while for option B, the seabed depth is the main one. Both layout options are modelled and the respective simulations were carried out using the Wind Atlas Analysis and Application Program (WAsP) to obtain the energy production estimates. Eventually, option B was selected as the best option due to a slightly higher energy output (due to smaller wake losses) and a larger number of turbines installed in shallower waters. Then, energy production and capacity factors were estimated for different percentiles, Table 3.1 summarizes the results.

Table 3.1 Energy production for OWF Punta Descartes. [33]

Percentile	MWh/year	Equivalent hours	Capacity Factor
P50	2.986.364	5.530	63,1%
P75	2.539.039	4.702	53,7%
P90	2.136.431	3.956	45,2%
P99	1.443.516	2.673	30,5%

The results above take into account the following losses across the wind farm:

- Wake losses 2,63%.
- Electricity transformation and transport 3,00%.
- Unavailability 3,00%.
- Substation maintenance 1,00%
- Hysteresis and blade dirt 2,00%

3.3 Grid Constraints Study

As part of the identification study, the ICE's Transmission Business Department carried out the grid connection analysis, and several issues where found. The analysis was based on the simulation of the national grid for a period comprehended between 2030 and 2039, and considering two different options for the connection of OWF Punta Descartes to the grid. Moreover, the actual improvement plans for the grid where considered and subsequently, to avoid additional investments the results obtained for the maximum power dispatches shown in Table 3.2.

Table 3.2 Maximum power dispatch for Punta Descartes without additional transmission investments.[33]

Year	Season	Max Dispatch (MW)
2030	Winter	50
	Summer	100
2039	Winter	50
	Summer	100

3.4 Cost & Benefit Analysis

Regarding the cost of the project, it is estimated considering an installed capacity of 540MW, for which the cost per type of input is disclosed as follows:

Table 3.3 Disclosed costs of the project. [33]

Item	Cost (USD)	%
DESCARTES OFFSHORE WIND PROJECT	**2.169.016.281**	**100%**
• FEASIBILITY STUDY	10.991.100	0,51%
• ENVIRONMENTAL FEASIBILITY	4.579.620	0,21%
• CONTRACTING AND PROCUREMENT	4.200.000	0,19%
• EXECUTION	2.149.245.561	99,09%
o Design	19.314.529	0,89%
o Construction	2.129.931.032	98,20%
▪ Project management	187.764.612	8,66%
▪ Environmental management plan	18.639.180	0,86%
▪ Civil works	236.102.029	10,89%
• Roads	4.081.562	0,19%
• Temporary facilities	232.020.467	10,70%
o Workshops and warehouses	34.349.946	1,58%
o Berth	197.670.521	9,11%
▪ Wind turbine assembly	1.573.727.293	72,55%
• Wind turbine foundation	724.189.573	33,39%
• Wind turbine installation	849.537.720	39,17%
▪ Electrical work	57.678.120	2,66%
• Wind turbine electrical connection	54.768.240	2,53%
• Wind turbine - TS collector connection	2.909.880	0,13%
▪ Transmission	56.019.798	2,58%
• Collector substation GIS	20.797.810	0,96%
• Tl collector - La Cruz	19.737.061	0,91%
• Conventional substation La Cruz	15.484.927	0,71%

The study uses data from the Generation Expansion Plan [74], where the optimal energy dispatch is calculated using the Stochastic Dual Dynamic Programming software (SDDP). Based on this optimal energy dispatch and according to economy theory, the short-run marginal cost (SRMC) of the electricity is what a generator should be paid in a hypothetical perfect market. The SRMC was determined from the average of the hourly-season bands shown in Table 3.4 for the 2019-2034 period.

Table 3.4 SRMC of the Demand USD_{2017}/MWh (2019-2034)

	Peak	Mid	Off-peak	Average
High Season (Jan-May)	115,4	109,7	98,6	105,9
Low Season (Jun-Dec)	11,8	7,7	7,6	8,2

Based on the data from Table 3.4, the percentile P50 in Table 3.1, and the monthly average capacity factor for the inland wind farms (from 2010-2019 historical performance data from the national electric system) the annual revenue per year was calculated as shown in Table 3.5.

Table 3.5 Monthly energy production and economic benefit. [33]

Month	CF[1] INLAND WF	Adjusted CF[1] for OWF P.Descartes	Energy (GWh)	MC[2] of Demand ($/MWh)	REVENUE (M$) [1]
January	67,6%	92,0%	369,71	105,9	39,2
February	67,2%	91,5%	331,90	105,9	35,1
March	67,9%	92,4%	371,27	105,9	39,3
April	53,5%	72,7%	282,85	105,9	30,0
May	32,0%	43,5%	174,89	105,9	18,5
June	32,8%	44,7%	173,62	8,2	1,4
July	50,6%	68,8%	276,54	8,2	2,3
August	34,6%	47,1%	189,11	8,2	1,6
September	20,3%	27,7%	107,58	8,2	0,9
October	17,2%	23,3%	93,80	8,2	0,8
November	47,8%	65,0%	252,91	8,2	2,1
December	65,3%	88,8%	356,67	8,2	2,9
Average	**46,4%**	**63,1%**			
Total			**2980,84**		**174,0**
1. Capacity factor 2. Marginal cost					

The low marginal costs of the low season respond to the fact that this is the rainy season in Costa Rica, when there is abundant hydroelectric generation, thus the cost of producing an extra MWh is low. In this season the revenue for any new project would be low, on the other hand, during summer, the revenue is higher, and especially advantageous for wind based electricity production as the summer is windier.

In the cost-benefit analysis of the project, the study considered a constant revenue throughout the life of the project, same assumption applies for the OPEX, some 54,27 M$/year (**2,5%** of the CAPEX). Additionally, a 12% discount rate was considered, results shown in [33] only show the final economic indexes for the project. In order to obtain the extended cost-benefit data, some reverse-engineering was carried out and the results are shown in Table 3.6.

[1] Millions of US Dollars

Table 3.6 Punta Descartes project cash flows (in M$).[1]

Year	CAPEX	OPEX	Total Cost	Revenue	Cash Flow
2020	-15,57		-15,57	0	-15,57
2021	-2,19		-2,19	0	-2,19
2022	-216,83		-216,83	0	-216,83
2023	-132,28		-132,28	0	-132,28
2024	-53,87		-53,87	0	-53,87
2025	-60,85		-60,85	0	-60,85
2026	-247,72		-247,72	0	-247,72
2027	-1.439,71		-1.439,71	0	-1.439,71
2028		-54,27	-54,27	174	119,73
2029		-54,27	-54,27	174	119,73
2030		-54,27	-54,27	174	119,73
2031		-54,27	-54,27	174	119,73
2032		-54,27	-54,27	174	119,73
2033		-54,27	-54,27	174	119,73
2034		-54,27	-54,27	174	119,73
2035		-54,27	-54,27	174	119,73
2036		-54,27	-54,27	174	119,73
2037		-54,27	-54,27	174	119,73
2038		-54,27	-54,27	174	119,73
2039		-54,27	-54,27	174	119,73
2040		-54,27	-54,27	174	119,73
2041		-54,27	-54,27	174	119,73
2042		-54,27	-54,27	174	119,73
2043		-54,27	-54,27	174	119,73
2044		-54,27	-54,27	174	119,73
2045		-54,27	-54,27	174	119,73
2046		-54,27	-54,27	174	119,73
2047		-54,27	-54,27	174	119,73
2048		-54,27	-54,27	174	119,73
2049		-54,27	-54,27	174	119,73
2050		-54,27	-54,27	174	119,73
2051		-54,27	-54,27	174	119,73
2052		-54,27	-54,27	174	119,73

From the cash flows shown in Table 3.6. some economic indicators were calculated in the identification study (see Table 3.7), concluding that the project is not economically feasible. Furthermore, the study highlights that in view of the results, the national electrical system does not require energy production at the prices that the project would incur, this applies for the short and mid run.

[1] Millions of US Dollars

Table 3.7 Punta Descartes OWF economic indicators. [33]

DR	NPV (M$)	IRR	B/C
12%	-705,27	2,42%	0,47

Where DR is the Discount Rate, IRR the Internal Return Rate and B/C the cost-benefit ratio. A negative NPV means that all money generated in the future won't compensate the initial investment cost.

3.5 Updated Economics

The first thing addressed is the updated estimation of energy produced by the OWF Punta Descartes. The identification study done in [33] considered a capacity factor for the percentile P50 of 63,1% and, as shown in Table 3.1 this decision implies an average energy production of 2 986,36GWh/year, meaning there is a 50% chance to exceed that energy production in a year. However, based on the information in IRENA's 2022 report, there are no capacity factors above 60% in the offshore wind sector as per 2021 available data. The reported weighted average capacity factors in the industry are shown in Figure 3.3.

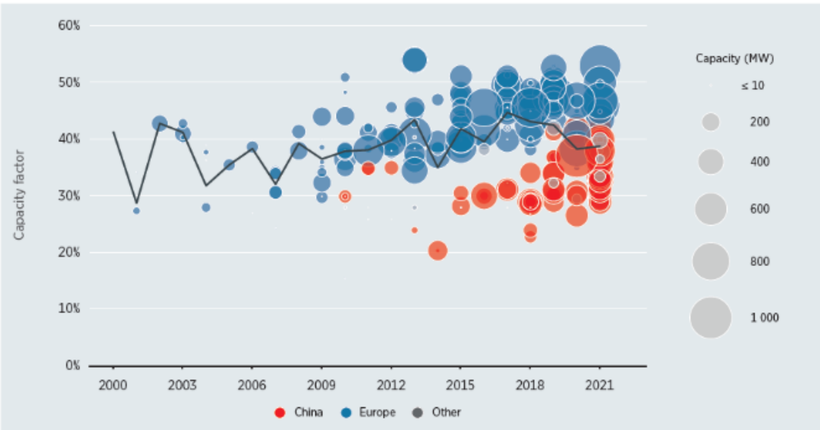


Figure 3.3 Project and weighted average capacity factors for offshore wind. Adapted from [16]

Consequently, and in order to adopt a more conservative approach, in this thesis the percentile P75 is used instead, with an average energy production of **2.539.039MWh** and capacity factor of **53,7%**. The selected capacity factor is still higher than the average factor for inland wind farms across the country (46,4%), which is common for offshore wind resources.

Another aspect that needs to be reviewed is the SRMC, mainly due to the impact that the COVID-19 pandemic had on the energy demand forecast. In the current Generation Expansion Plan the forecasted demand for the 2020-2035 decreased, consequently, the plan does not contemplate the renovation of purchase contracts for some private generators. Moreover, the sort-run marginal cost of energy dispatch decreased significantly, the current forecasted values are presented in Table 3.8.

Table 3.8 SRMC of the Demand USD_{2019}/MWh (2020-2035) [27].

	Peak	Mid	Off-peak	Average
High Season (Jan-May)	66	65	58	62,3
Low Season (Jun-Dec)	2	2	2	2,0

Then, considering the aforementioned parameter variations for the project, a new annual average revenue is calculated with the same approach as in Table 3.5, obtaining the following results.

Table 3.9 Monthly energy production and economic benefit.

Month	**CF[1] INLAND WF**	**Adjusted CF[1] for OWF P.Descartes**	**Hours**	**Energy (GWh)**	**MC[2] of Demand ($/MWh)**	**REVENUE (M$)[3]**
January	67,6%	78,2%	744	314,32	62,3	19,6
February	67,2%	77,8%	672	282,22	62,3	17,6
March	67,9%	78,6%	744	315,71	62,3	19,7
April	53,5%	61,9%	720	240,73	62,3	15,0
May	32,0%	37,0%	744	148,79	62,3	9,3
June	32,8%	38,0%	720	147,59	2,0	0,3
July	50,6%	58,6%	744	235,27	2,0	0,5
August	34,6%	40,0%	744	160,88	2,0	0,3
September	20,3%	23,5%	720	91,34	2,0	0,2
October	17,2%	19,9%	744	79,97	2,0	0,2
November	47,8%	55,3%	720	215,09	2,0	0,4
December	65,3%	75,6%	744	303,62	2,0	0,6
Average	**46,4%**	**53,7%**				
Total			**8760**	**2.539,04**		**83,6**

1. Capacity factor 2. Marginal cost 3.Millions of USD

In comparison with the revenue calculated in the identification study, the updated value represents only the 48% of it. This variation is very significant, and even more when it affects the most sensible parameter for the NPV of an offshore wind farm, the strike price, as it has been presented in Figure 2.7. Following the same economic analysis as in Table 3.6, the following economic indicators are obtained.

Table 3.10 Punta Descartes OWF updated economic indicators.

DR	**NPV (M$)**	**IRR**	**B/C**
12%	-1.025,29	-6,68%	0,22

As expected, the NPV now is still negative and even significantly lower than the original scenario. The negative IRR occurs when the aggregated value of cash flows is less than the initial investment.

As mentioned in Section 2.1.2, the LCOE facilitates a cost-wise comparison between different options, in this case it is calculated to compare the original scenario developed in Punta Descartes identification study, with the updated scenario presented in this thesis. (3.1 is used to calculate the LCOE and is taken from [75].

$$LCOE = \frac{\sum_{n=0}^{N}\left[\frac{C_n}{(1+d)^n}\right]}{\sum_{n=1}^{N}\left[\frac{Q_n}{(1+d)^n}\right]} \tag{3.1}$$

Where C_n are the costs in period n , Q_n is the energy output, d is the discount rate and N is the number of years in the analysis period.

The period of time under study is the same for both scenarios, from 2020 to 2052. The LCOE for the original identification study is **0,13 $/kwh** and for the updated scenario is **0,15 $/kwh**, those values are high when compared to the global weighted LCOE found in the industry. Figure 3.4 shows the evolution of the LCOE for the offshore wind industry, where the average value for 2020 is about **0,075 $/kwh**. In summary, Punta Descartes LCOE is near twice of that of the industry for the base year of the study.

Source: IRENA Renewable Cost Database.

Figure 3.4 Offshore wind project global weighted LCOEs and auction/PPA prices, 2000-2021. Adapted from [16].

It is worth noticing that 540MW of installed capacity was used in the cost-benefit analysis carried out in [33] and the updated version in this thesis. Nonetheless, as mentioned in Section 2.1.4 the current and future state of the national grid won't be able to accommodate the full capacity of the project without major investments. One section in the identification study addresses the stability of the national transmission grid, and the study concludes that the maximum capacity for the initial operation of the project is **150-200MW** in 2030, and up to **350MW** in 2039.

In the following sections, the feasibility of green hydrogen production is studied, in order to see how it could impact the overall economics and feasibility of Punta Descartes OWF.

CHAPTER 4

Methodology

In this chapter, the different technical and economic parameters for hydrogen production are analyzed. First, a reference case is defined, this would work as the baseline for the rest of the cases. Next, hydrogen production systems are proposed for three cases, based on the characteristics of the project and taking into account the latest technology updates. Afterward, the operation and resulting production of electricity/hydrogen/oxygen is calculated for each case. Finally, a cost & benefit study is carried out besides a sensibility analysis which explores the impact of some parameters on the NPV of the coupled OWF-Hydrogen project proposal.

The reference year for the whole analysis is defined as 2030, which is the expected start year of any offshore wind project at commercial scale in Costa Rica [76]. Additionally, the study in this thesis is limited to the stage of hydrogen and oxygen production, hence, no storage, distribution or final uses of the gases produced are included within the scope.

4.1 Cases Definition

In this thesis one reference case and three cases for hydrogen production are proposed as follows:

- Reference Case: Dedicated electricity production.
- Case 1. Dedicated hydrogen production without grid assistance.
- Case 2. Grid assisted hydrogen-electricity production with PEM technology.
- Case 3. Grid assisted hydrogen-electricity production with ALK technology.

There are common characteristics of the hydrogen production system that apply for all cases. To start with, due to the short distance from the wind turbines to the shore all power circuits connect directly to the onshore substation, and there is no need for any offshore substation. The characteristics of the power circuits are shown in Table 4.1.

Table 4.1 Proposed electric power circuits.[33]

Circuit	Length (m)	Capacity (MVA)	Voltage (kV)	Current (A)
1	3.695	150	69	1.255
2	3.950	210	69	1.757
3	5.975	180	69	1.506

The fact that there is no need for an offshore platform benefits the overall cost of the project. In 2019 the cost of an offshore substation was about 120M£ for a 1GW wind farm according to [14], near 82,3M$ (3,8% of the total cost) considering a 1,27 £/$ exchange rate and a proportional adjustment for the 540MW of the project. Thus, the hydrogen production facility would be located onshore at the same location of the substation.

Then, the main inputs of the system are electricity and water. For the electrolysis process the purity of the water is very important, hence, fresh water is preferred over sea water so the pre-treatment equipment is less complex and cheaper. Nevertheless, the location defined for the port and substation does not count on a reliable and source of fresh water. The onshore substation and subsequently the electrolyzer would be located on Mostrencal Beach, in the district of La Cruz, where drinking water service is often suspended due to reparations and scarcity in the dry season.

Some small creeks are found in the whereabouts of the future substation location as shown in Figure 4.1, however there is no data about their water flow and the region is known for going dry in many occasions, which even causes eco-stress to local vegetation [77].

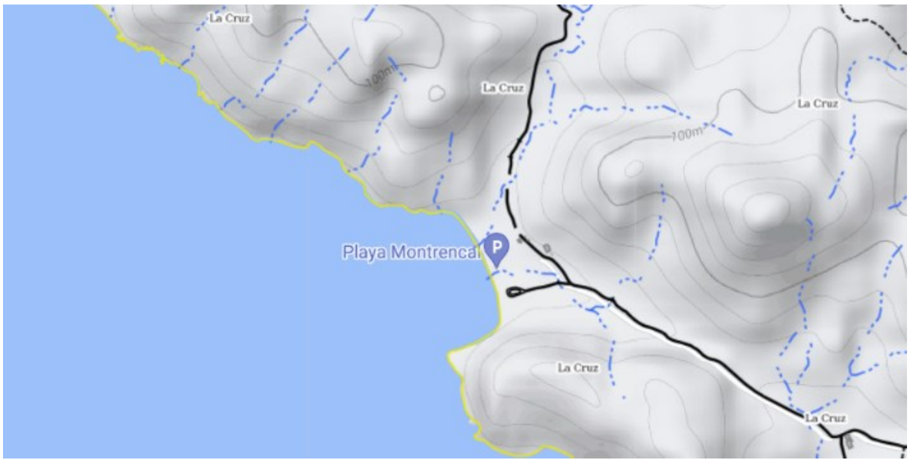


Figure 4.1 Water bodies in the vicinity of the facilities.

Therefore, the electrolysis process has to be fed with seawater and considerations must be taken in order to procure the best systems and adequate technology. Nevertheless, sea water desalination have been found to have limited penalties on cost or efficiency, in the order of 0,01$/kg H_2 [41], this value is added to the calculated LCOH and LCOO (levelized cost of oxygen) in the cost & benefit study.

Another general assumption for all cases is the benefit from oxygen sell. O2 production is a byproduct of the electrolysis, this process offers high qualities at “low” production costs, and it has been highlighted as a key enabler for the rollout of H2 projects [78]. Oxygen use from the electrolysis process is already being explored in some projects, the flagship project Port of Amsterdam is looking at a 100 MW electrolyzer that would produce 15,000 tons/y of green hydrogen and create oxygen for the steel site as well [40].

In order to analyze the commercially available large scale technologies, the analysis is limited solely to ALK and PEM technologies. It is assumed that electrolysis plants would have reached capacities up to 540MW by 2030. Additionally, as the analysis in this thesis is limited to the production of the gasses, consequently, no compression or transport costs are included in the cost-benefit section. Section 2.2 presented an overview of the main characteristics of ALK and PEM technologies, with state of the art data and future projections/forecasts from several sources and as a summary, Table 4.2 presents the applicable parameters for the subsequent analysis.

Table 4.2 Summary of applicable parameters for electrolysis technologies.

PARAMETER	YEAR	PEM	ALK
STACK LEVEL			
Electrical efficiency (kWh/kg$_{H2}$)	2050	< 42	< 42
Stack Lifetime (kh)	2030 2050	50 - 85,0 100-120	62,3 - 100 100
Degradation (%/y)	2030	0,12	0,10
CAPEX (Currency/kW)	2025 2050	€210 < $100	€215 < $100
SYSTEM LEVEL			
Electrical efficiency (kWh/kg$_{H2}$)	2030 2050	50 < 45	47,84 - 48 < 45
Cold start (to nominal load)	2020 | 2050	<20 | <5min	< 50 | <30min
CAPEX (Currency/kW)	2030 2050	€1.038 - 500 < $200	€750 - 400 < $200
OPEX (%CAPEX/y)	2030	2,10 – 2,00	2,08 - 2,00

The following sub-sections of this work elaborate on the techno-economics behind the selected technologies, the costs for each proposed case and the corresponding estimation of energy production.

4.2 Systems and Technologies

4.2.1 Reference Case: Dedicated electricity production.

This case is based on the identification study in [33], the OWF capacity is assumed to be 540MW with the same costs as in the study. The main difference with the identification study is the grid dispatch restriction. As explained in Section 3.3, in the forecasted capacities of the national grid, the OWF project would be able to dispatch a maximum of 100MW during summer season and 50MW in winter season (rainy season).

Hence, for the analysis in this thesis, a grid connection capacity of **100MW** is assumed. This assumption affects greatly the electricity output of the project and consequently, the cost & benefit results would be far worse than the ones presented in Sections 3.4 and 3.5.

The rest of the tech-related factors stay the same, i.e., 54 wind turbines of the selected SeaTitan™ 10 MW model [79]. The foundations are the same steel Jacket type and the wind farm layout the same option B as in Figure 3.2. Electrical equipment and transmission lines stay as in the identification study.

For the rest of the cases, the baseline regarding the OWF and grid connection when applicable, are the same as in this reference case.

4.2.2 Case 1: Dedicated hydrogen production without grid assistance.

In this first case, the electrolyzer will be exposed to every variation of the wind resource, making response time one (if not the most) important criteria for the technology selection. Regarding this flexibility, PEM technology appears as the best available option, as Table 4.2 shows.

Furthermore, there are several studies on sea water electrolysis, in which different technologies are addressed. In the multicriteria study in [80] (8 different criteria), PEM resulted to be to answer to the question of “What is the best electrolysis technology for producing hydrogen from seawater and marine renewable energies in a sustainable manner?”. Moreover, regarding the CAPEX and based on the projections in Figure 2.22, PEM would also be very competitive in the long run thanks to technological learning.

Besides reductions in the CAPEX, lifetime of the stack is also expected to improve significantly, in some estimates it even surpasses ALK stacks lifetime, thus, PEM technology is selected as the preferred technology in this case.

Regarding the size of the electrolyzer, capacity varies significantly across countries as Figure 4.2 shows. Nevertheless, optimal electrolyzer capacity for variable renewable energy sources (VRES) is found anywhere between 30% and 60% of the power generation capacity. This proportion would depend on the share of PV versus wind, capacity factors of PV and wind, battery installed capacity, and seasonality of resources, among other factors [39].

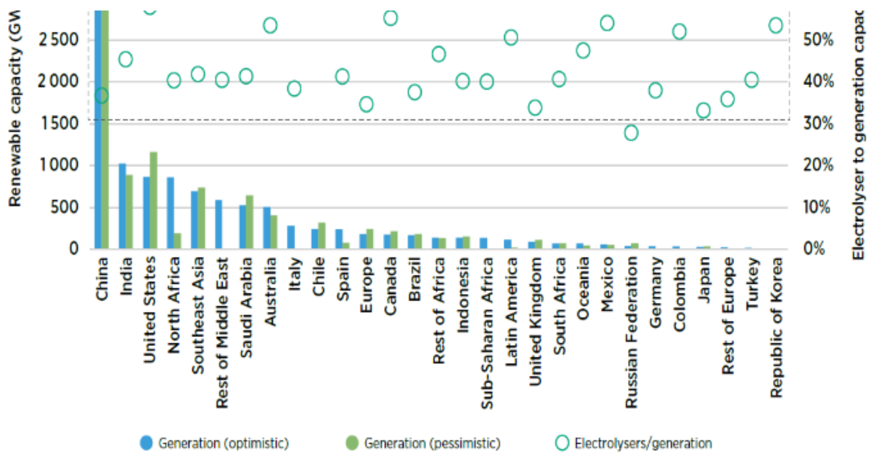


Figure 4.2 Installed renewable generation capacity for hydrogen production and associated electrolyzer capacity by region in 2050 for optimistic and pessimistic scenarios. Adapted from [39].

Therefore, based on Figure 4.2, a **50%** is define as the ratio between the offshore wind resource and electrolyzer capacity. Thus, a hypothetical electrolyzer capacity of **270MW** is assumed as the reference parameter for case 1.

4.2.3 Case 2: Grid-assisted PEM hydrogen-electricity production.

For this case, several restrictions apply, being the first one the maximum dispatch power defined in the transmission analysis included in [33]. As described in Table 3.2, the maximum power that the national grid would be able to handle is projected to be 100MW, leaving 440MW available for hydrogen and oxygen production.

In order to take advantage of the grid connection, this case explores the impact of having the electrolyzer working at nominal capacity as much as possible. As mentioned in Chapter 1, there is about **917,4GWh/y** of green electricity surplus in the Costa Rican to be exploited, from which only 48% had been historically allocated in the regional market. Hence, it is assumed that this electricity surplus is available for hydrogen production.

Regarding the size of the system and to compare a similar baseline with the Case 1, the capacity of the electrolyzer is also set at **270MW.**

4.2.4 Case 3: Grid-assisted ALK hydrogen-electricity production.

This case is mostly oriented towards comparing PEM and ALK under the same restrictions, thus, the specific characteristics of each technology will result in different hydrogen production values and different cost structures. For instance, when intending to operate the equipment at nominal capacity; higher the efficiency, longer stack life, and the lower CAPEX/OPEX need to be considered.

Additionally, the second best option in the study in [80] was the Alkaline Electrolysis (ALK), which performed well on all economic criteria, while scoring lower on the environmental/social criteria. In this thesis, the approach is more oriented towards improving the feasibility of Punta Descartes OWF, thus, ALK is selected for this second case.

Once again, in order to compare a similar baseline with the Case 1 and Case 2, the capacity of the electrolyzer is also set at **270MW.**

4.3 Operation & Production

4.3.1 Wind Resource.

The first step of the production chain is to address the energy resource. In [33], data from a nearby onshore meteorological station was used, this was the best available data as there are no onsite measurements. The 13 months' data was then processed with the Measure-Correlate-Predict (MCP) method to have a correction of local measurements, discarding wrong values and predicting missing ones. Afterwards, long-run data for a 40y period at 60m was obtained using reanalysis data from MERRA 2 database, for this end, Windographer software and the MTS algorithm were used. The final data series obtained are summarized in the Weibull diagram shown in Figure 4.3.

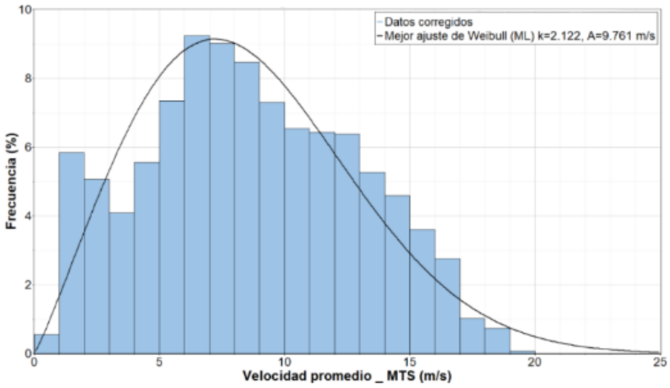


Figure 4.3 Histogram and Weibull distribution of the data series with the long-run correction from MERRA 2 data using the TSM[1] algorithm. Adapted from [33].

The resulting wind data has an associated uncertainty, this is due to several factors, including the representability that the onshore meteorological station could have over the actual offshore location of the project. Hence, the total associated uncertainty of wind speed values was estimated as 10,9% [33].

For this thesis, as no publicly available data was found for the wind resource, synthetic hourly values for one year are generated, using data reported in the identification study and the software HOMER. The monthly mean wind speeds are presented below.

Month	V (m/s)
Jan	11,9
Feb	12,9
Mar	11,5
Apr	10,2
May	7,3
Jun	6,6
Jul	8,3
Aug	7,0
Set	5,5
Oct	5,6
Nov	7,8
Dec	9,9

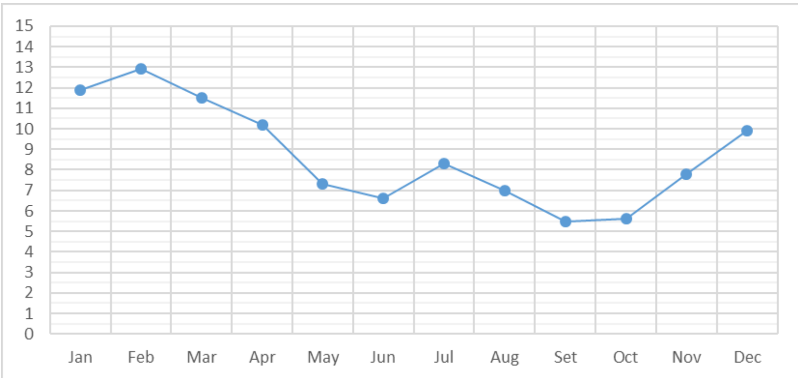


Figure 4.4 Monthly mean wind speeds for Punta Descartes OWF [2].

In order to use these monthly values in HOMER, other parameters need to be defined:

- Weibull shape factor k: **2,122**. Same as in Figure 4.3
- Autocorrelation factor: **0,95**. Areas surrounded by more uniform topography tend to have high (0.90 - 0.97) autocorrelation factors [81].
- Hour of peak wind speed $\emptyset$: **10am**. Read from the mean diurnal profile taken from [33].
- Diurnal pattern strength factor δ: **0,12**. It reflects how strongly the wind speed tends to depend on the time of day. This factor is obtained from the equation for the synthetic average diurnal profile in HOMER as follows:

$$U_i = \bar{U}\left\{1 + \delta cos\left[\left(\frac{2\pi}{24}\right) * (i - \emptyset)\right]\right\} \quad (4.1)$$

[1] Time Series Matrix
[2] Extracted from the corresponding graph in [33].

Where: U_i is the mean wind speed in hour i (m/s), $\bar{U}$ is the overall mean wind speed (m/s), δ is the diurnal pattern strength (0 to 1 number), $\emptyset$ is the hour of peak wind speed (1 to 24).

The mean diurnal profile extracted from the identification study and the obtained cosinusoidal curve for the synthetic data points is shown in Figure 4.5.

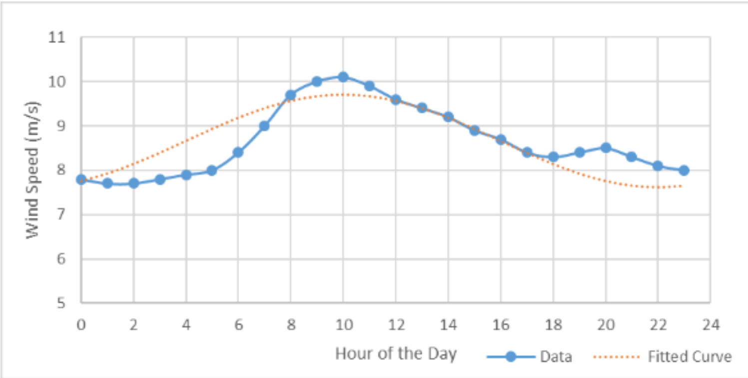


Figure 4.5 Average diurnal profile for measured wind speed and synthetic data.

Once all the parameters are defined, HOMER generates 8760 values for all the hours of the year, this data is summarized in Figure 4.6.

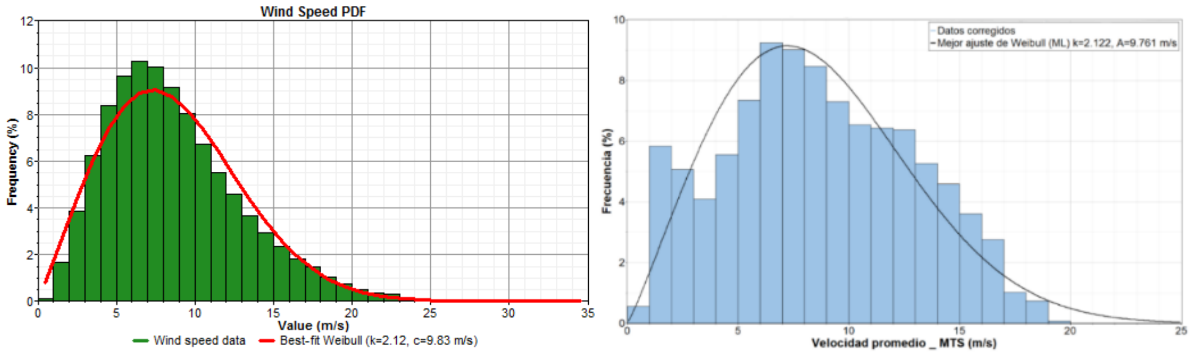


Figure 4.6 Histogram and Weibull distribution of the synthetic and original data series.

Comparing both data series, the synthetic data has a similar mean wind speed of 9,83m/s vs 9,76m/s in the original set. There are some differences in the distribution of frequencies, for instance, in the original set, wind speeds between 1m/s and 2m/s occur with a frequency near to 6% of the time, but in the synthetic data set, those speeds occur only 3% of the time. Nevertheless, as all cases use the same data set, the impact of differences between the original and synthetic data sets does not affect the final economic analysis of the different technologies.

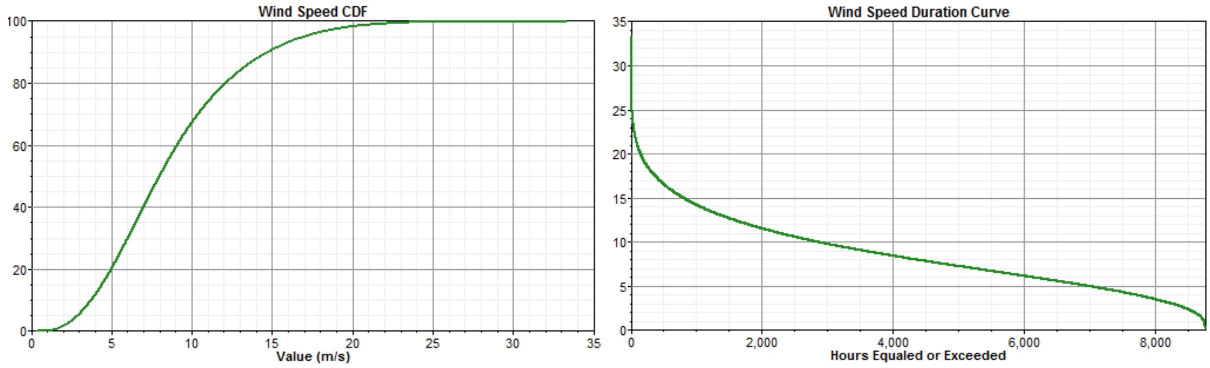


Figure 4.7 Wind speed cumulative frequency (%) and duration (h) curves.

For a final comparison of the obtained synthetic data, as shown in Figure 4.7, there are about 7500h of wind speeds exceeding 4m/s (wind turbine cut in speed), this represents 85,6% of the time vs 88,5% in the original set. Henceforth, the data obtained from HOMER is considered a little bit more conservative than the original one.

4.3.2 Energy conversion

With the wind resource data generated, the next step is to determine the energy produced by the OWF for every hour of the year and to do so, the power curve of the SeaTitan wind turbine is used. The working parameters of the turbine are shown in

Table 4.3 Wind turbine operating data

Operating Data	Value
Cut-in wind speed (m/s)	4
Rated wind speed (m/s)	11,5
Cut-out wind speed (m/s)	30
Grid frequency (Hz)	50-60
Hub height (m)	125

For the energy output calculation, the power output curve is extracted from manufacturers graph by using the operating limits and a curve approximation as shown in Figure 4.8.

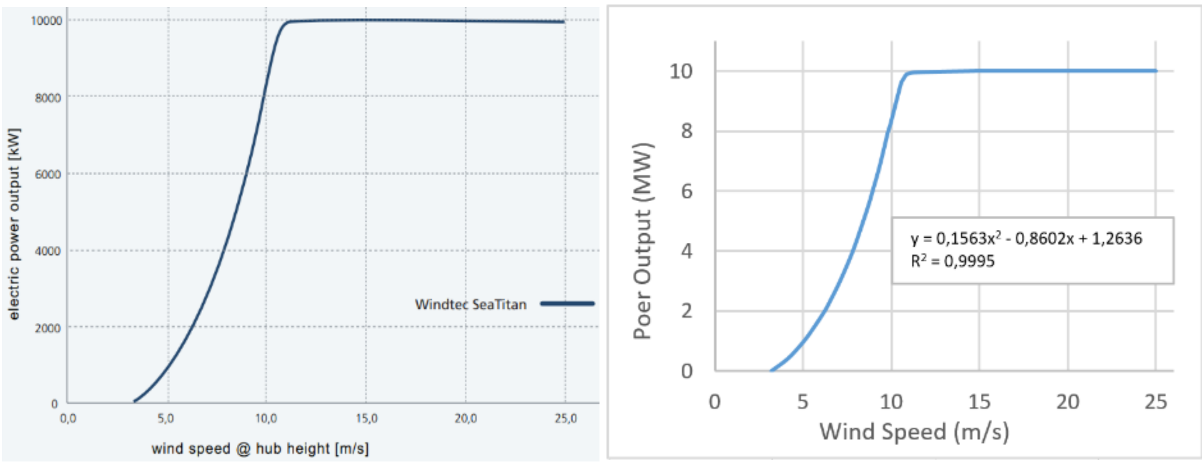


Figure 4.8 SeaTitan™ 10 MW original power curve [79] and generated power curve.

Finally, as there is a difference in height between the meteorological station to the actual hub height, a logarithmic profile correction factor is considered, this factor is applied to the power output value obtained from the power curve.

$$\frac{v(z_{hub})}{v(z_{anem})} = \frac{ln(z_{hub}/z_0)}{ln(z_{anem}/z_0)} \tag{4.2}$$

Where z_{hub} is the hub height of the wind turbine (m), z_{anem} is the anemometer height (m), z_0 is the surface roughness (m), $v(z_{hub})$ is the wind speed at hub height (m/s) and $v(z_{anem})$ is the wind speed at anemometer height.

As the anemometer of the meteorological station is located on the shoreline and at a height of 71,59m above sea level (base of the station tower at 11,59m plus 60m of tower height), and for simplicity, it is assumed that roughness has a value of 0,0005m corresponding to a "Blown sea" value from

Table 4.4 Terrain roughness factors [82].

Terrain Description	z_0 (m)
Very Smooth, ice or mud	0,00001
Calm open sea	0,0002
Blown sea	0,0005
Snow surface	0,003
Lawn grass	0,008
Rough pasture	0,010
Fallow field	0,03
Crops	0,05
Few trees	0,10
Many trees, few buildings	0,25
Forest and woodlands	0,5
Suburbs	1,5
City center, tall buildings	3,0

Finally, the annual energy output of the wind farm is obtained, with a value of **2.520.244MWh** and a capacity factor of **53,28%**. On the other hand, the original energy production for percentile P75 presented in Section 3.5 is 2.539.039MWh and capacity factor of 53,7%, consequently, with less than 1% of difference between the original and the synthetic data, the obtained hourly wind speeds and the corresponding energy production values are considered as valid for the rest of the analysis.

It is important to highlight that, as the energy obtained with the synthetic data matches the P75 energy output from [33], which already considered wake losses and another 9% of other losses, hence, no additional energy losses are considered for the synthetic energy production obtained.

4.3.3 Reference Case: Dedicated electricity production.

In the reference case, the maximum export power is caped to 100MW. From a development point of view, this limitation would force developers to install less turbines and recalculate the whole project feasibility. Nonetheless, the objective of this research is to determine the economic impact of hydrogen production with the limited connection capacity, the aforementioned max export power is considered.

Hence, in this case, any power output above the grid connection limit is considered as excess energy and it is therefore curtailed. The subsequent cases explore the impact that different electrolysis systems could have on the techno-economics of the project, in comparison to this base case.

4.3.4 Case 1: Dedicated hydrogen production without grid assistance.

For this configuration, energy produced by the OWF is supplied to the 270MW PEM electrolysis facility. The efficiency of the PEM system is assumed to be a constant rate of 50 kWh/kg_{H2} and to have no minimum load requirements, and consequently it would produce hydrogen proportionally to its power input from 0% to 100% of its capacity.

4.3.5 Case 2: Grid-assisted PEM hydrogen-electricity production.

This is the first case in which the hydrogen production depends not only on the energy supplied by the wind farm, but also on the prices of electricity and hydrogen evaluated on an hourly basis. In order to evaluate the best operation strategy, a simple operation model is developed using Excel software. This model finds the most profitable output per hour, meaning, it would choose between producing hydrogen or exporting electricity to the grid.

Additional restrictions also apply, for instance, when exporting or up-taking electricity to and from the grid, a maximum power transfer of 100MW applies. Another restriction that is considered in this case is the PEM electrolyzer capacity of 270MW. In order to have a more graphical image of the model, the following schematics present the main blocks considered.

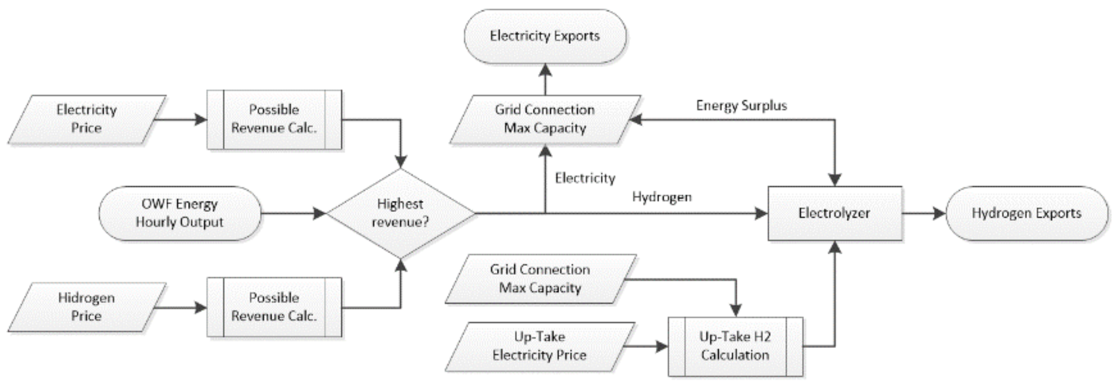


Figure 4.9 Production model schematics.

In order to explain the production model in a more detailed manner, four examples are presented:

1. Electricity is more profitable → OWF energy higher than grid max: in this scenario, electricity is exported up to 100MWh, then the surplus is fed into the electrolyzer and limited by its capacity. Any remaining energy is considered as curtailed.
2. Electricity is more profitable → OWF energy lower than grid max: here, all energy from the OWF is exported as electricity and there is no hydrogen production.

3. Hydrogen is more profitable → OWF energy higher than electrolysis capacity: electricity from the OFW is used to produce hydrogen, once the electrolyzer reaches its maximum capacity, excess electricity is exported to the grid. Then, if the grid connection maximum is reached, the remaining energy is curtailed.
4. Hydrogen is more profitable → OWF energy lower than electrolysis capacity: in this scenario, all energy from the OWF is used to produce hydrogen. If the production of hydrogen with imported electricity from the grid is profitable, then up-take electricity is used to reach electrolyzer's max capacity but considering the grid connection capacity as well.

4.3.6 Case 3: Grid-assisted ALK hydrogen-electricity production.

This case is almost identical to Case 2, with the difference of the technology used for the electrolysis. Alkaline electrolyzers are considered, this implies a lower energy consumption of 48 kWh/kg_{H2} vs the 50 kWh/kg_{H2} as shown in Table 2.4. Moreover, alkaline electrolyzers have a minimum partial load at which they can operate, in this case a 10% minimum partial load is assumed based on [83].

4.3.7 Additional assumptions

For the results obtained with the proposed model, some assumptions were made and those are explained in this section.

One of the main suppositions is that no electrical grid improvements other than the ones projected in [27] are expected in 2030. Thus, as presented in Table 3.2, a maximum power dispatch of 100MW is assumed in the model.

It is also assumed that electricity exports do not obey the national power demand curve, this implies that energy produced by the OWF is favored over other power generation plants, mainly hydropower plants as those are easy to ramp up and down.

Another assumption is related to the technical operation of the electrolyzers, it is assumed that both electrolyzers can switch their power output in an hourly base. If for instance, at hour "X" the electricity input is 200MW and at hour "X+1" the input is 250MW, there are no energy losses due to system's ramp up time. Maintenance is planned during no production hours, this is, when there is little to non-exploitable wind resource, which according to the synthetic data obtained, adds up to **1042** hours.

For the hydrogen production estimates and for simplicity of the production model, no degradation of electrolyzer's cells over time is considered. Two main causes of performance degradation have been observed over time. The first one is directly related to the purity of the feed water and is reversible, and the second one is irreversible and due to the degradation of the MEAs[1] [84]. Degradation can account up to 12% loss of efficiency over the life spam of the stack [43].

[1] Membrane Electrodes Assemblies

4.4 Cost & Benefit Analysis

4.4.1 OWF costs

The costs related to the development and construction of the OWF were disclosed in Section 3.4, the costs corresponded to market prices for 2021. Nevertheless, as shown in Figure 2.12, some costs reductions due to technological advances are expected, hence, CAPEX of the OWF in 2021 is reduced 15% towards 2030. Hence, the CAPEX of the OWF goes from 2.169M$_{2020}$ to 1.844M$_{2030}$.

Cases that consider a connection to the grid would contemplate the full investment of 1.844M$, whereas case 2 only considers 1.814M$ of CAPEX for the OWF. This difference is a result of the savings incurred by not having to connect the onshore substation to the grid and the respective transmission line and equipment needed, accounting for 1,62% of the total cost of OWF as it was showed in Table 3.3.

The specific costs avoided in Case 1 are highlighted in red in Table 4.5

Table 4.5 Avoided costs in Case 1.

• Transmission	56.019.798	2,58%
○ Collector substation GIS	20.797.810	0,96%
○ Tl collector - La Cruz	19.737.061	0,91%
○ Conventional substation La Cruz	15.484.927	0,71%

It is worth noticing that the cost of the onshore station “Collector substation GIS” refers to a substation for the full nameplate capacity of 540MW for the OWF. Although the cost of the onshore collector substation, and the transmission infrastructure should be less for a 100MW limited grid connection, in this thesis the full original cost is considered.

Regarding the OPEX of the wind farm, it is assumed to be 2,5% of the CAPEX per year, coincidently with the ratio used in the identification study in [33]. Another cost that is considered in this thesis is that derived from the decommissioning (DECEX) of the OWF at the end of its life, which is set to **3,0%** of project’s CAPEX.

Backing up this DECEX assumption, a model was developed in [85], which was parameterized with data from four proposed U.S. offshore wind farms. The decommissioning costs were found to range from 115,000 to 135,000 $/MW (approximately 3% to 4% of project’s CAPEX). Besides, this decommissioning cost results take into account the residual value of the materials recovered from the OWF, as it can be inferred from Table 4.6.

Table 4.6 Expected decommissioning costs at proposed U.S wind farms, adapted from [85].

Windfarm	Capacity (MW)	Turbines	Removal (M$)[1]	Disposal (M$)	Scrap Revenue (M$)	Total (M$)
Coastal Point, TX[1]	150	60	24,5	0,9	1,9	23,4
Bluewater, DE	450	150	68,3	1,7	10,3	59,7
Garden State, NJ[1]	350	96	47,7	1,8	4,2	45,3
1. Projects to use tripod / jacket foundation.						

[1] Millions of US Dollars

No other costs for the OWF are included in the cost & benefit analysis developed in this thesis.

4.4.2 Electrolyzers costs

The first main assumption made on the cost of the electrolysis systems is related to the CAPEX, for which it is considered that it covers the electrolyzer system (the stack), the necessary balance of plant equipment (drier, cooling, de-oxo and water de-ionization equipment), civil works (terrain, building and foundations) and electricity grid connection.

Based on the information in Table 4.2, CAPEX of 500€/kW and 400€/kW is assumed for the PEM and ALK systems respectively. Because all other values in the model are in USD, the CAPEX values are converted to USD_{2030} using 1,13 as the average rate (1 EUR = 1,13USD), calculated from the long-term forecast in [86]. Besides the capital expenditure, the OPEX is considered as 2% of the CAPEX for both technologies.

Furthermore, based on the capacity factors obtained with the production model and life spans of 85000h and 100000h for PEM and ALK stacks respectively, it was found that it would be necessary to replace the stacks in all cases. In more detail, stacks are expected to last 14,75 years for Case 1, 11,93 for Case 2 and 14,71 for Case 3. Consequently, stack replacement cost is considered in the Cost & Benefit analysis, ranging from 210€/kW for PEM system to 215€/kW for ALK stacks.

Lastly, a decommissioning cost is also considered at the end of life of the project. For simplicity, the DECEX is assumed to hold the same proportion as for the OWF, i.e. 3,0% of the CAPEX.

4.4.3 Electricity costs

Regarding the electricity uptake price, on the 20^{th} of December 2022 a new electricity tariff was made available and tailored for green hydrogen production. Under the label T-UD (direct user tariff), this tariff was created in order to facilitate the use of the curtailed electricity in the national grid in the new economy of green hydrogen. Prices are shown in Table 4.7.

Table 4.7 Direct user tariff in USD_{2022}/MWh [87]

Peak	Mid	Off-peak
50	50	40

Consequently, it is assumed that any energy drowned from the grid to produce hydrogen would be paid at 50 $/MWh. Moreover, due to the fact that hydrogen storage systems are not within the scope of this thesis, it is not possible to buy electricity when it is cheaper and store it as hydrogen.

4.4.4 Revenue

In this Cost & Benefit analysis, capital income comes from three different sources: electricity, hydrogen and oxygen sales. The main assumption for the revenue is that the entire production of the combined OWF-Electrolyzer system is positioned in the market, i.e. there are no market restrictions or curtailment for electricity, hydrogen or oxygen.

Electricity Sales

In the Cost & Benefit analysis presented in Section 3.4, it was explained that the short-run marginal cost (SRMC) of the electricity is what a generator should be paid in a hypothetical perfect market. Nevertheless, in view of the variability found of this parameter in Costa Rica (summarized in Table 4.8), and the effort that governments should put to provide long term price stability in the offshore wind market, a different approach is explored to define electricity prices.

Table 4.8 Short-run Marginal Cost of the demand in Costa Rica.

USD_{2017}/MWh (2019-2034)	**Peak**	**Mid**	**Off-peak**	**Average**	**Reference**
High Season (Jan-May)	115,4	109,7	98,6	105,9	[74]
Low Season (Jun-Dec)	11,8	7,7	7,6	8,2	[74]
USD_{2019}/MWh (2020-2035)					
High Season (Jan-May)	66	65	58	62,3	[27]
Low Season (Jun-Dec)	2	2	2	2,0	[27]

Sale price of electricity is assumed equal to the average rates shown in Table 4.9, which shows the Costa Rican electricity exports to the regional electricity market.

Table 4.9 Costa Rican electricity exports to the Regional Market in 2021 [26].

Costa Rican Electricity Exports to the Regional Market 2021							
	South Contract		**North Contract**		**Total**		
Month	**MWh**	**USD**	**MWh**	**USD**	**MWh**	**USD**	**AVG Rate USD/MWh**
Jan			46.159,40	2.046.741,16	46.159,40	2.046.741,16	44,34
Feb			16.154,42	830.797,33	16.154,42	830.797,33	51,43
Mar			4.695,00	232.500,00	4.695,00	232.500,00	49,52
Apr	252,00	11.004,00	13.086,00	640.342,20	13.338,00	651.346,20	46,30
May			20.001,00	976.888,68	20.001,00	976.888,68	48,84
Jun			39.428,34	2.156.254,66	39.428,34	2.156.254,66	54,69
Jul			51.292,02	2.769.809,04	51.292,02	2.769.809,04	54,00
Aug			64.498,14	3.482.899,51	64.498,14	3.482.899,51	54,00
Set			56.961,65	3.075.928,61	56.961,65	3.075.928,61	54,00
Oct			47.731,62	2.577.507,64	47.731,62	2.577.507,64	54,00
Nov			49.983,56	2.699.112,51	49.983,56	2.699.112,51	54,00
Dec	274,88	18.210,00	52.412,18	2.898.401,52	52.687,06	2.916.611,52	60,77

Consequently, there are 3 scenarios where energy is exported as electricity:

1. When electricity sale is more profitable than hydrogen sale.
2. When hydrogen sale is more profitable and the electrolyzer max capacity is exceeded.
3. When hydrogen sale is more profitable but OWF power output is less than ALK electrolyzer minimum partial load.

Hydrogen Sales

While electricity prices are evaluated in a monthly base, hydrogen price is assumed invariable across the period of time under study; i.e. 8760h of the generated synthetic wind speed data. A simplistic approach is followed to determine the volume of sales, a price rate of 3,0USD is selected based on Figure 2.20 for the whole year in study, and it is applied to the hydrogen production obtained from the operation model.

Oppositely to electricity sales, energy is converted to hydrogen in the next scenarios:

1. When hydrogen sale is more profitable than electricity sale and OFW power output is within operational loads for the electrolyzers.
2. When electricity sale is more profitable and the grid connection max capacity is exceeded.

Oxygen Sales

As explained in Section 4.3, oxygen is considered a byproduct of hydrogen production, thus, its revenue is considered only in the Cost & Benefit analysis and not as an input in the operation model. In other words, the operation model would determine the hydrogen production for each case disregarding possible oxygen income.

Once hydrogen production is calculated, it is assumed that for every 9L of water there are 1kg of hydrogen and 8kg of oxygen [88] to obtain oxygen production. In a study from 1994 of an oxygen enriched combustion system for the United States glass industry, it was found that using a VPSA[1] system, oxygen could be produced at costs of $30 to $35/ton as Figure 4.10 shows. Hence, translating those prices to the base year of this thesis study (2030) with an inflation rate of 2%, oxygen price is assumed in the range of $0,06 – $0,07/kg.

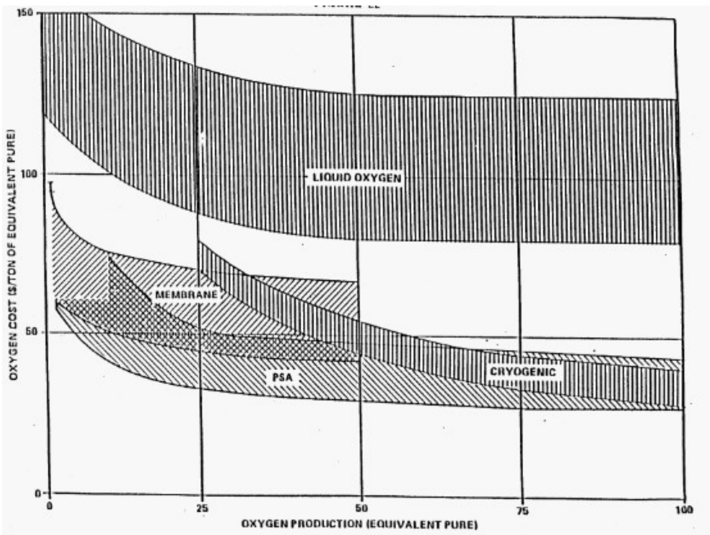


Figure 4.10 Oxygen cost vs production 100% utilization. Adapted from [89].

[1] Vacuum Pressure Swing Adsorption

It is worth to notice that the aforementioned range of prices are for an onsite production with the appropriate VPSA equipment. Oxygen as a commodity in the international market was in the range of \$0,12 – \$0,18/Nm^3 in November 2017 [90], using a conversion factor of 1,4291kg/Nm^3 [91] the previous range can be expressed as \$0,08 - \$0,13/kg. Translating again those values to 2030 inflated prices, the range is \$0,10 – \$0,17/kg, consequently, an intermediate price of **\$0,10/kg** is used in this thesis, which is between onsite production and market price.

The price defined before, is considered for the oxygen production on site, this means, that no storage, transportation or other costs are then considered.

4.4.5 Discounted cash flow

With all costs and revenues defined, a discounted cash flow analysis is performed for a project life of 25 years. The first parameter to be defined is the **Discount Rate**. There are several discount rates that an investor or business can choose when evaluating a project or investment, for instance:

- Opportunity cost-based discount rate.
- Weighted average cost of capital (WACC)
- Historical average returns of a similar projects
- Risk-free rate

When investing in assets like treasury bonds, the Risk-free rate is often used as the discount rate. On the other hand, if a business is assessing the viability of a project, the WACC could be used as a discount rate [92]. The WACC represents how much does raising capital cost to a business, and is a measure used to assess whether or not to invest in a new project [22].

In Costa Rica the telecommunications regulatory body establishes the WACC for telecommunication projects at 11,17% post-taxes and **12,13%** pre-taxes [93], being the former used in this study. Using a higher discount rates imply a reduced present value of the future cash flows, and the impact this parameter has on the economics of a project is unneglectable. For instance, with a 5.5% WACC for an average Northern European OWF, an additional 1% in the WACC increases the LCOE between 5% to 10% [94].

In this Cost & Benefit study, inflation is considered and it affects all goods sales (electricity, hydrogen and oxygen), operational costs and decommissioning costs. It is included in the calculation when determining the Real Discount Rate as follows:

$$RDR = \frac{WACC - InR}{1 + InR} \tag{4.3}$$

Where RDR is the Real Discount Rate and InR is the inflation rate.

Inflation is a measure of economy-wide price increases from year to year; it is generally represented by the Consumer Price Index (CPI) or Producer Price Index (PPI). Nevertheless, inflation varies among sectors or commodities; specific values can be found for wind turbine prices (Bloomberg Wind Turbine Price Index), overall power-plant costs (IHS Power Capital Costs Index), and electricity prices [95].

While the European Central Bank (ECB) expected this to decline towards its target of 2% over the course of 2022, the outlook for inflation and the overall European economy depends on how the situation develops in Ukraine [22]. However, the Organization for Economic Cooperation and Development (OECD) shows a very worst scenario and forecasts inflation rates above 5% at the end of 2023. Hence, in an optimistic approach, an inflation rate of **4%** is assumed for the analysis and the corresponding RDR is **7,82%.**

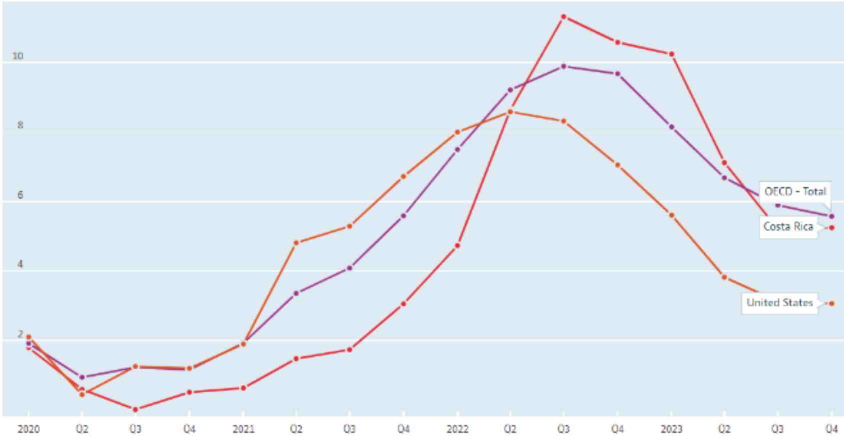


Figure 4.11 Inflation forecast for Total, Annual growth rate (%), Q1 2020 – Q4 2023. Adapted from [96].

The study also considers the depreciation of the wind turbines, which according to the Costa Rican Legal Information System is calculated as 5% annually or 20 years to full depreciation [97]. Lastly, a corporate income tax is also included in the discounted cash flow analysis, which according to PricewaterhouseCoopers is 30% in Costa Rica [98].

In summary, the following values for the economic parameters are used in the analysis:

Table 4.10 Discounted cash flow study parameters.

Economic parameters	
WACC	12,13%
Inflation Rate	4,00%
Real Discount Rate	7,82%
Depreciation per year	5,00%
Corporate Tax	30,00%

CHAPTER 5

Results and Discussion

Before diving into the specific results for each case under study, a quick safety check was run to check if the minimum partial load of the ALK electrolyzer could have a significant impact on results. The aim of the exercise was to determine if the NPV of the project using an ALK system would fall considerably if the electrolyzer minimum partial load was 20% instead of 10%. The results are shown in Figure 5.1.

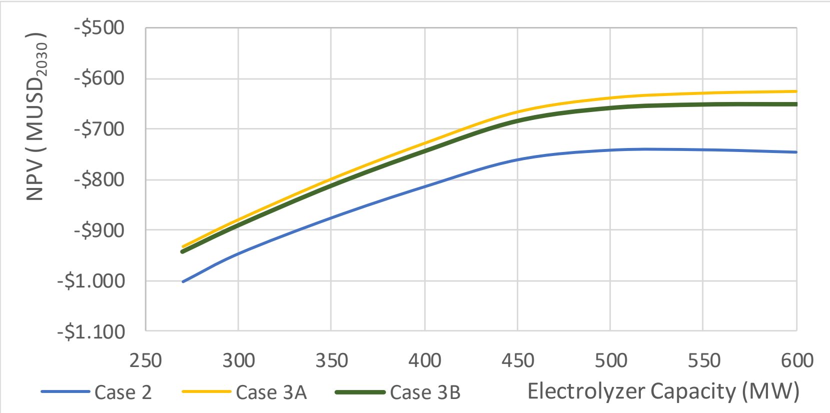


Figure 5.1 NPV of ALK electrolyzer system at 10% and 20% minimum partial load.

Although there is a negative impact on the NPV of the ALK system with higher minimum partial load, it is not significant enough to make it less attractive than the PEM system (Case 2). Furthermore, a higher minimum load means that there would be more hours of the year where the ALK system cannot run, but due to the fact that in the cases under examination there is the option of exporting electricity, the overall economics are not greatly affected.

Another verification was carried out to see if in an off-grid scenario (similar to Case 1) the minimum partial load of the ALK system could play a decisive role, but results showed that based on the synthetic wind speed data used, the ALK system still generates 3% more income than the PEM system.

5.1 Reference Case

Results in this case show that from the possible energy production of the OWF, only **699.141MWh** can be effectively poured into the national grid (27,74% of P75 annual average energy) with 309,12$/MWh of LCOE. In other words, in this case, a **72,26%** of the estimated energy production is not exploited, this is entirely due to the 100MW limitation of the national grid connection.

If Punta Descartes is to be developed with its full nameplate capacity, significant additional investment is necessary to have get the national grid up to handle farm’s power output. Hence, this reference case is a portrait of what a developer could find in 2030; on a business as usual scenario.

The dispatched electricity is priced as in Table 4.9 and generates a gross income of $35.034.750. This gross income is then assumed for the lifetime of the project and the respective discounted cash flow study is performed, the NPV and B/C[1] obtained are **- 1.971M$** and **0,16** respectively. As no positive cash flows are obtained in this case, no valid IRR could be calculated.

If the maximum dispatch power restriction is eliminated, this reference case would have similar conditions to the original Cost & Benefit study done in [33]. Main difference between the original identification study and this thesis are:

- This thesis considers a mean annual production of 2.520.244MWh (capacity factor of 53,28%), similar to P75 in the identification study (2.539.039MWh, capacity factor of 53,7%). Instead, the original Cost & Benefit study considered a P50 production of 2.986.364MWh (capacity factor of 63,1%). Consequently, the energy production in this thesis is about 15% lower than in [33].
- The Cost & Benefit study in the identification study does not consider either inflation, depreciation or corporate taxes, and the discount rate used is 12% instead of the 7,82% RDR used in this research.
- CAPEX in this thesis is assumed to occur completely in year 0 (2030), when reductions of 15% are expected to be in place as shown in Figure 2.12.
- Decommissioning expenditure of capita (DECEX) is not included in the original study.
- Electricity strike prices in [33] are based on the forecasted 2019-2034 short-run marginal cost (SRMC) of demand in Costa Rica, 105,9$/MWh and 8,2$/MWh (57,05$/MWh annual average) for high and low season respectively. Then, the updated forecasted 2020-2034 SRMC in [27] is 62,3$/MWh and 2,0$/MWh (32,15$/MWh annual average), accounting for the impact of COVID-19. In view of this variability, the present study takes a power purchase agreement approach based on the monthly export prices of electricity from Costa Rica to the regional market (52,16$/MWh annual average).

In the hypothetical case of a full capacity grid connection, the model estimates a NPV of - 1.058,48M$, and IRR of -0,59% and a B/C of 0,56. Table 5.1 shows a comparison of the Cost & Benefit studies covered in this thesis.

Table 5.1 Comparison of Cost & Benefit studies against the reference case.

DR	NPV (M$)	IRR	B/C	Study
12,00%	-705,27	2,42%	0,47	Cost & Benefit in [33]
12,00%	-1.025,29	-6,68%	0,22	Updated Cost & Benefit with info from [27]
7,82% [1]	-1.058,48	-0,59%	0,56	Hypothetical Cost & Benefit analysis (540MW grid connection)
7,82% [1]	-1.969,50	NR [2]	0,16	Final Cost & Benefit analysis (100MW grid connection)
1. Real Discount Rate 2. No result, no positive cash flows to calculate IRR				

[1] Benefit over Cost ratio.

The objective of the previous exercise is to visualize the impact of the assumptions taken in the reference case. Henceforth, the rest of the cases are compared to the Reference Case with the limitation of 100MW connection to the grid, as defined in Section 4.1.

5.2 Case 1

In the first case, the OWF annual production of 2.520.244MWh is used to produce only hydrogen with the PEM system. The resulting annual production is 38.122.924 kg_{H2} which represents an 65,79% capacity factor for the electrolyzer system and an income of $93.368.773 per year. Oxygen production is about 248.983.396 kg_{O2} with an income of $24.898.340.

Although there is a high production of hydrogen, not all the energy produced at the wind farm is being used, there are 964.098MWh that are not exploited due to electrolyzer capacity limit. This unexploited energy represents a 38,25% of the estimated production.

Then, the LCOH and LCOO for this case are 7,48$/kg and 0,93$/kg respectively. For the economic indicators, the NPV is -1.253,52M$, the IRR -1,9% and the B/C is 0,42. In comparison with the reference case, case 1 brings to the project 718M$ more for the NPV.

5.3 Case 2

Based on the operation logic explained in previous sections, the 2.520.244MWh from the OWF produce 399.823MWh of electricity dispatch, 38.463.282 kg_{H2} and 248.983.396 kg_{O2}. Respectively, the income from each output are $19.940.256, $115.389.846 and $30.770.626 for a total annual income of $135.258.040.

The hydrogen production in this case means 81,31% of capacity factor for the electrolyzer system. The curtailed energy in this case is lower than the previous cases, totaling 586.172MWh, or 23,25% of the OWF energy production. The LCOE, LCOH and LCOO are 539,87$/MWh, 6,63$/kg and 0,83$/kg respectively. While electricity is more expensive to produce when compared to Case 1 (due to less exports), hydrogen and oxygen are produced at lower costs.

From the total hydrogen production, 7.778.307 kg_{H2} are produced using electricity imported from the grid. This hydrogen can still be considered green hydrogen, this is due to the fact that near 98% of Costa Rican electricity is generated from renewable energy as explained in Section 2.1.4.

On the economics, the NPV of the project in this case is -993,51M$, the IRR 0,8% and the B/C is 0,47. When compared to the reference case, there are 975,98M$ more in the NPV.

5.4 Case 3

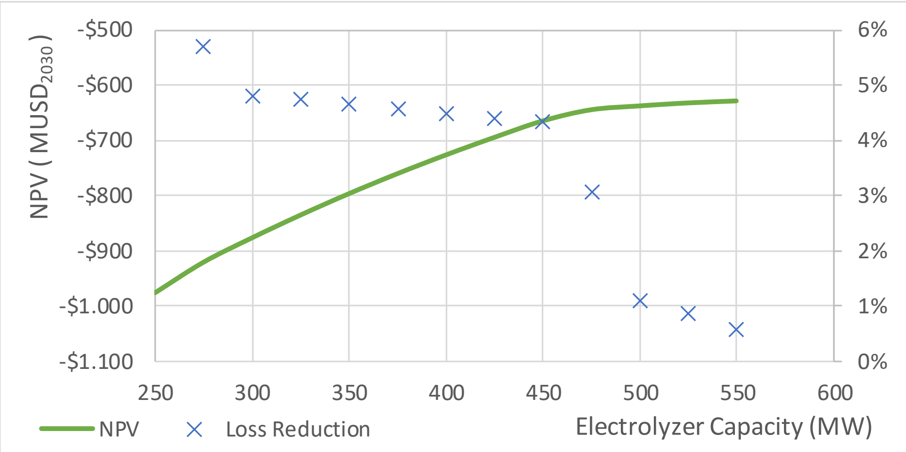
With the same production model of case 2, the alkaline system exports 383.118MWh of electricity, 38.238.670kg_{H2} and 305.909.356kg_{O2}, with the ALK electrolyzer operating with a 77,60% capacity factor. The LCOE is 563,41$/MWh which is the highest of all cases, then the LCOH is 6,44$/kg being the cheapest of all alongside with the cheapest LCOO of 0,80$/kg.

The curtailed energy in this case resulted to be the same as in case 2, a total of 586.172MWh (23,25%) of the estimated energy production. Additionally, from the total hydrogen production, 5.927.135 kg_{H2} are produced using electricity imported from the grid.

On the sales side, hydrogen generates $114.716.009, electricity $18.877.146 and oxygen $30.770.626 for a total of $164.363.780 in total sales. The NPV of Case 3 is -925,45M$, some 1044,05M$ more than the reference case, then the IRR is 1,2% and the B/C 0,48, both the best of all cases.

5.5 Electrolyzer Size

In Figure 5.1 it was shown how increasing the size of the electrolysis systems impacts positively the NPV of the project. Based on that observation, a similar exercise is carried out to determine a convenient size of the electrolyzer facilities and Figure 5.2 shows the results.



Size	NPV	Growth Rate
250	($977)	
275	($921)	5,7%
300	($877)	4,8%
325	($835)	4,7%
350	($796)	4,7%
375	($760)	4,6%
400	($726)	4,5%
425	($694)	4,4%
450	($664)	4,3%
475	($643)	3,1%
500	($636)	1,1%
525	($631)	0,9%
550	($627)	0,6%

Figure 5.2 ALK electrolyzer capacity vs NPV.

Its observed how increasing the capacity of the electrolyzer improves the NPV. More specifically, moving from 250MW to 275MW increases the NPV 5,7%, then, escalating power from 275MW to 450MW generates about 4,6% increments of NPV on each 25MW step. Conversely, stepping from 450MW and above; only brings increments lower than 3% in NPV.

On the capital expenditure side, increasing the electrolyzer size from 270MW (baseline size for all cases with electrolyzers) to 540MW (OWF's nameplate power) would only represent a 6,2% higher CAPEX for the whole project. Hence, under the conditions studied, more parameters need to be considered to determine the electrolyzer size. For instance, a developer could choose to install an ALK system with the capacity of the OWF to have the best NPV possible, but then it would have a prohibiting environmental impact.

5.6 Summary

The following table summarizes the main techno-economic results obtained from the operation model and the Cost & Benefit analysis.

Table 5.2 Techno-economic results summary.

	Elec. (GWh)	H2 (ton)	O2 (ton)	Excess (GWh)	LCOE ($/MWh)	LCOH ($/kg)	LCOO ($/kg)	NPV (M$) [1]	IRR	B/C
R.Case	699	NA	NA	1.821	309	NA	NA	-1.972	NR	0,16
Case 1	NA	31.123	248.983	964	NA	7,48	0,93	-1.254	-1,9%	0,42
Case 2	400	38.463	307.706	586	3.272	6,65	0,83	-1.002	0,7%	0,47
Case 3	383	38.239	305.909	586	NR	6,45	0,81	-931	1,2%	0,48

In view of the results obtained, the case that has a greater positive impact on the NPV and IRR of the project is the third one. Hence, based on the research done, the production model and the Cost & Benefit analysis, the ALK system is selected as the best option to improve the feasibility of Punta Descartes.

It is worth noticing that differences are not too significant between PEM and ALK technologies, for instance, if the efficiency of the PEM system was assumed to be 48kWh/kg instead of 50kWh/kg (4% improvement), its NPV would be - 940,40M$, the IRR 1,3% and the B/C 0,49 which would mean it is the best option. Therefore, even though ALK is chosen as the best option, PEM technology in 2030 would be perfectly competitive from a techno-economic analysis stand point.

A different approach would be necessary to determine the best technology in a scenario where the project could be developed, several criteria should be considered aside of the techno-economics. Some examples of other factors to consider are: Social, environmental, resistance to impurities in water, swiftness of response to variations, cell degradation endurance, reliability of electrolyzer supply chain, environmental life cycle assessments, scarcity of materials, manufacturer/provider assistance, among others.

Although all the studied cases improve considerable the economic metrics of the reference case, still the project falls short on its feasibility. With a grid restriction of 100MW, electrolysis plant of 270MW, and the rest of assumptions in place, hydrogen sell price needs to be above 6,17$/kg to have a positive net present value of the project.

5.7 Sensitivity Analysis

The sensitivity analysis is carried out to see the impact that variations in different parameters have on the NPV and IRR metrics of Case 3, as ALK technology is selected as the most beneficial for Punta Descartes OWF. The following parametric values are considered in this sensitivity analysis.

[1] Millions of US Dollar

Table 5.3 Parametric table for the sensitivity analysis

	Parameter Variation						
	-15%	**-10%**	**-5%**	**0%**	**5%**	**10%**	**15%**
Grid dispatch capacity (MW)	85	90	95	100	105	110	115
Electrolyzer capacity (MW)	229,50	243,00	256,50	270,00	283,50	297,00	310,50
Electrolyzer consumption (kWh/kg)	40,80	43,20	45,60	48,00	50,40	52,80	55,20
Minimum partial load - ALK	8,50%	9,00%	9,50%	10,00%	10,50%	11,00%	11,50%
WACC	10,31%	10,92%	11,52%	12,13%	12,74%	13,34%	13,95%
Inflation Rate	3,40%	3,60%	3,80%	4,00%	4,20%	4,40%	4,60%
Corporate Tax	25,50%	27,00%	28,50%	30,00%	31,50%	33,00%	34,50%
CAPEX OWF (M$$_{2030}$/MW)	2,90	3,07	3,24	3,41	3,58	3,76	3,93
CAPEX System (EUR$_{2030}$/kW)	340	360	380	400	420	440	460
CAPEX Stack (EUR$_{2030}$/kW)	182,75	193,50	204,25	215,00	225,75	236,50	247,25
OPEX OWF (% of CAPEX)	2,13%	2,25%	2,38%	2,50%	2,63%	2,75%	2,88%
OPEX ALK (% of CAPEX)	1,70%	1,80%	1,90%	2,00%	2,10%	2,20%	2,30%
DECEX (% of CAPEX)	2,55%	2,70%	2,85%	3,00%	3,15%	3,30%	3,45%
Electricity Price Factor [1]	0,85	0,90	0,95	1,00	1,05	1,10	1,15
H2 Sell Price ($/kg)	2,55	2,70	2,85	3,00	3,15	3,30	3,45
O2 Sell Price ($/kg)	0,085	0,090	0,095	0,100	0,105	0,110	0,115

1. This factor is applied to the monthly electricity prices considered in the model.

The analysis was carried by changing the value each parameter while keeping the others unmodified. Results show that four parameters have a marked greater impact on the NPV, namely; the CAPEX of the project (in M$/MW), the energy consumption of the electrolysis system (in kWh/kg), the weighted average cost of capital (WACC) and the sell price of hydrogen, in that order. Figure 5.3 shows the results obtained for the NPV of the project.

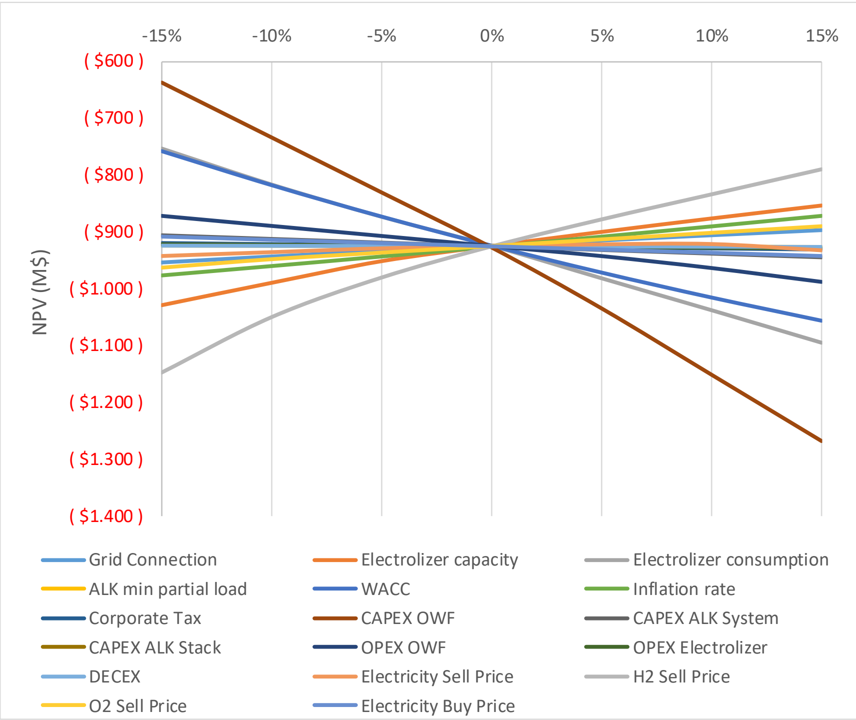


Figure 5.3 Sensitivity of the NPV indicator.

Reductions of CAPEX can be achieved in different ways, and one of the most important is increasing turbine sizes [24]. Although the cost of the turbine itself increases with size, on the other hand, larger turbines imply less units for a given power in a defined area. Moreover, less units also imply reductions in the balance-of-system and reduced operations and maintenance costs [99], besides an increased annual energy production.

Similarly, for the IRR the mayor variations are linked to adjustments in the CAPEX of the OWF, the efficiency of the electrolyzer and the sell price of the hydrogen, as Figure 5.4 shows.

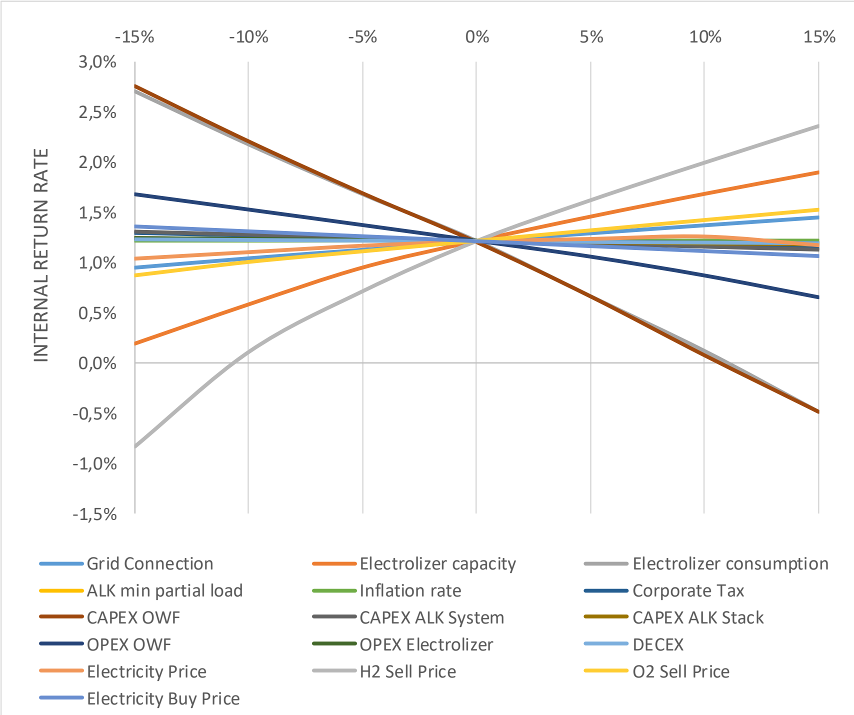


Figure 5.4 Sensitivity of the IRR indicator.

5.8 Conclusions

Three cases where defined and compared against a reference case to see if the production of hydrogen brings any benefits to the project. The reference case had the OWF producing and exporting only electricity to the grid through a 100MW limited connection. The first case presented a dedicated hydrogen production using PEM technology. The second case included a grid-assisted hydrogen production again with PEM technology. The third and last case was similar to the second but implementing ALK technology, being the latter the option that offered major benefits.

The techno-economic analysis carried out aimed at uncovering the possible benefits of hydrogen production for Punta Descartes OWF. Based on the methodology used and the conditions/assumptions considered, the results showed that:

- ALK electrolysis system is by a narrow margin, the best option for hydrogen production from the offshore wind resource at Punta Descartes locations.
- For the chosen ALK system and under the defined conditions, electricity exports could reach 383.118MWh, which represents about, 83% of the North Contract exports in 2021. Then, the green hydrogen and oxygen productions are 38.238.670kg_{H2} (covering the projected national demand by 2030) and 305.909.356kg_{O2} respectively.
- Due to the gird assisted model, the ALK electrolyzer capacity factor is estimated at 77,60%.
- The LCOE is 563,41$/MWh, then the LCOH is 6,44$/kg and the LCOO of 0,80$/kg.
- The curtailed energy resulted to be 586.172MWh, 23,25% of the estimated energy production of the OWF.
- From the total hydrogen production, 5.927.135kg_{H2} are produced using electricity imported from the grid.
- On the sales side, hydrogen generates $114.716.009, electricity $18.877.146 and oxygen $30.770.626 adding up to $164.363.780 in total sales per year.
- The NPV - 925,45M$, some 1.044,05M$ more than the reference case. The IRR is 1,2% and the B/C 0,48.
- Punta Descartes offshore wind farm is not economically feasible even with the implementation of green hydrogen production facilities.

Although all the studied cases improve considerable the economic metrics of the reference case, still the project falls short on its feasibility. With a grid connection restricted to 100MW, electrolysis plant of 270MW, and the rest of assumptions in place, hydrogen sell price needs to be above 6,17$/kg to have a positive net present value of the project.

Based on the documentary review, it is clear that the offshore wind industry and market has been steadily growing. Installed capacity of projects has evolved from 5MW to 43,3GW, with single turbine powers outputs hitting up to 12-16MW. Larger turbines are also reaching the market more frequently, with rotor diameters reaching 252m. Moreover, some sources estimate the global installed capacity at 261GW and project 286GW by 2031.

In the Costa Rican context, studies on the offshore wind subject have estimated the technical resource potential in the range of 14,4GW-17GW. One project location has been identified, the offshore wind farm Punta Descartes could eventually add 540MW more to the national green power generation matrix. Nevertheless, considering the limitations of the electrical grid, only some 150-200MW could be connected in the initial stages of the project.

Regarding the enabling condition for the offshore market, studies have been carried out to find the deeds and gaps for the implementation of the ocean energy supply chain. Furthermore, it was found that roadmap for ocean energy has already been created and collected in the report “The Ocean Energy Pathway for Costa Rica”.

Regarding the hydrogen context, in 2021 hydrogen production was 1 million tons (Mt), practically all of it using CCUS. By 2030 the production could reach 16-24 Mt per year, with 9-14 Mt of green hydrogen, which translates into more than 10x growth in a decade. As far as installed electrolysis capacity, HyDeal is the largest planned project up to date and will count with 7,4GW of electrolyzers.

Some projections see green hydrogen being cheaper than any low-carbon alternative (*i.e.* < USD 1/kg), before 2040[41][41]. Regarding the evolution of electrolyzers, recent technologies claim to reach up to 98% energy efficiency at cell level, with energy consumption of 40,4 kWh/kg_{H2} and the trend is to have new technological advances coming on a fast pace.

In the Costa Rican context, studies have forecasted green hydrogen production with LCOH in the range of 1,24$/kg$H_2$ to 5,1 $/kg$H_2$. In high hydrogen demand scenario, demand from seven industrial sectors could reach **32ktonH_2** by 2030. There is a handful of organizations that have been working on the enabling conditions for the green hydrogen market. One of the achievements in this line is the definition of the National Strategy for Green H_2 of Costa Rica, opening the pathway for international investment.

The analysis of the techno-economical study carried out previously for Punta Descartes OWF, and the subsequent updated version in this thesis, revealed the importance of having clear and long-term policies regarding electricity sell prices. This is due to the fact that, the strike sell price of the electricity appeared to be most significant factor projects feasibility, as explained in Section 2.1.2.

Finding the optimal electrolyzer size for Punta Descartes OWF requires a deeper analysis with more parameters than the techno-economic ones used in this thesis. Increasing the electrolyzer size from 270MW to 540MW (OWF’s nameplate power) would represent only a 6,2% higher CAPEX for the whole project. Thus, other criteria additional to the NPV or the IRR should be used to determine the optimal electrolyzer size.

The analysis shows that four parameters have a marked greater impact on the NPV, namely; the CAPEX of the project (in M$/MW), the energy consumption of the electrolysis system (in kWh/kg), the weighted average cost of capital (WACC) and the sell price of hydrogen ($/kg$H_2$), in that order.

5.9 Recommendations

- There are several approximations and assumptions regarding the wind resource data, i.e., data in the original identification study is from a nearby onshore meteorological station, and data used in this thesis was generated using HOMER software based on the available Weibull distribution. The previous conditions favor the spreading of uncertainty and thus, it is highly recommended to run onsite and more accurate measuring campaigns to determine the wind resource.
- Since the offshore wind industry is evolving and new wind turbine models reach the market on a fast pace, it is recommended to review the costs estimation of the OWF and the project power output simulation. Nowadays, wind turbines of up to 16MW are available, thus, turbines of at least 12MW should be used in further feasibility studies.
- Costa Rican policy makers have to work on setting and improving enabling conditions for both the offshore and green hydrogen industries, as the country has a strong position to become a regional leader in the renewable energy sector. Clear rules and long term stability for electricity prices are crucial to attract project developers to the country.
- Even though Punta Descartes project is not economically feasible under the conditions and assumptions considered, committees for technology surveillance should be established. The racing pace of technology advances, could make both offshore wind and green hydrogen an attractive option to decarbonize Costa Rican transportation sector and provide the country with energy autonomy.
- More studies should be carried out to determine the feasibility of green hydrogen production from onshore wind. This recommendation is based on the fact that offshore resource is still unviable from the economic standpoint, and Costa Rica counts with a mature wind industry.

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ANNEX I

This annex presents some captures of the MS Excel Model developed, showing some of the formulas used to obtain the results.