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Luana de Souza Gaspar

Optimal risk-averse design of green hydrogen projects in Brazil: a stochastic optimization approach

Dissertação de Mestrado

Dissertation presented to the Programa de Pós–graduação em Engenharia Elétrica, do Departamento de Engenharia Elétrica da PUC-Rio in partial fulfillment of the requirements for the degree of Mestre em Engenharia Elétrica.

Advisor: Prof. Alexandre Street de Aguiar

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Abstract

Gaspar, Luana de Souza; Aguiar, Alexandre Street de (Advisor). **Optimal risk-averse design of green hydrogen projects in Brazil: a stochastic optimization approach**. Rio de Janeiro, 2024. 38p. Dissertação de Mestrado – Departamento de Engenharia Elétrica, Pontifícia Universidade Católica do Rio de Janeiro.

Despite the relevant role of green hydrogen in the pathway to net zero, its market is still developing, mainly due to its high production cost compared with gray hydrogen. An optimal portfolio selection, considering the grid as a backup, is needed to achieve a cheaper and more stable electricity supply and, thus, reduce costs in the short term. Other aspects can help reduce costs, such as demand flexibility, reduction of perceived risks, and the implementation of hydrogen storage. An optimization model was developed and implemented in Julia programming language to test and analyze the impact of these aspects on hydrogen production costs and project design. Using the model, it was possible to conclude that the usage of the grid as a backup has the most relevant impact on the levelised cost of hydrogen (LCOH), reducing it from 6.4 USD/kg in the reference case to 4 USD/kg. However, the possibility of using the grid while still complying with the European regulation for RFNBO will be at risk if the share of electricity produced using fossil fuel increases in the Brazilian power matrix. Without the possibility of using the grid, Brazilian hydrogen projects will need to adopt other flexibility and risk aversion methods to reduce the LCOH and still maintain a possible position in the international hydrogen market.

Keywords

Green Hydrogen; Power supply optimization; Hybrid power plants; Hydrogen storage; Demand profile.

Resumo

Gaspar, Luana de Souza; Aguiar, Alexandre Street de. **Desenho avesso ao risco ótimo para projetos de hidrogênio verde no Brasil: uma abordagem de otimização estocástica**. Rio de Janeiro, 2024. 38p. Dissertação de Mestrado – Departamento de Engenharia Elétrica, Pontifícia Universidade Católica do Rio de Janeiro.

Apesar do papel relevante do hidrogênio verde no caminho para a neutralidade climática, seu mercado ainda é incipiente, especialmente devido ao seu alto custo de produção em comparação ao hidrogênio cinza. Para reduzir custos no curto prazo, é necessária uma seleção ótima de portfólio, considerando a rede como um backup, para atingir um fornecimento de eletricidade mais barato e estável. Outros aspectos podem ajudar a reduzir custos, como flexibilidade de demanda, redução de riscos percebidos e implementação de armazenamento de hidrogênio. Para testar e analisar o impacto desses aspectos nos custos de produção de hidrogênio e no design do projeto, um modelo de otimização foi desenvolvido e implementado na linguagem de programação Julia. Usando o modelo, foi possível concluir que o uso da rede como backup tem o impacto mais relevante no custo nivelado de hidrogênio (LCOH), reduzindo-o de 6,4 USD/kg no caso de referência para 4 USD/kg. No entanto, a possibilidade de usar a rede e ainda cumprir a regulamentação europeia para RFNBO estará em risco se a participação de energia gerada com combustíveis fósseis aumentar no sistema elétrico brasileiro. Sem a possibilidade de usar a rede, os projetos brasileiros de hidrogênio precisarão adotar outros métodos de flexibilidade e aversão ao risco para reduzir o LCOH e ainda manter uma possível posição no mercado internacional de hidrogênio.

Palavras-chave

Hidrogênio Verde; Otimização do fornecimento de energia; Usinas híbridas; Armazenamento de hidrogênio; Perfil da Demanda.

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1
Introduction

Global temperatures in 2023 reached the highest level on record, which began in 1850, with an average of 1.48 ° C above preindustrial levels [1]. As seen in Figure 1.1, this is not an isolated event but a part of an ongoing global warming trend, which, as stated in [2], has unequivocally been caused by human activities, principally through emissions of greenhouse gases (GHG). A rapid and profound reduction in GHG emissions is necessary to limit global warming to, better, 1.5 ºC or, at maximum, 2ºC above preindustrial levels [2], which were the targets agreed upon in the Paris Agreement [3]. To achieve a low carbon future, transitioning from fossil fuels without carbon capture and storage (CCS) to very low- or zero-carbon energy sources will be necessary [2].

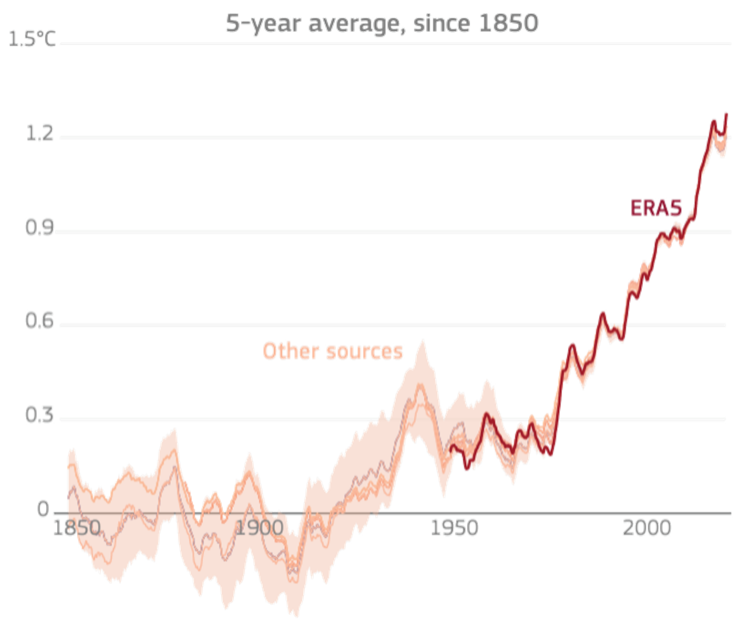

Figure 1.1: Global surface temperature: increase above preindustrial level (1850 - 1900) [1]

Hydrogen is included in several decarbonization roadmaps, such as in [4] and [5], as a relevant solution to reduce the dependency on fossil fuels, especially in sectors that are difficult to electrify, such as heavy industry and long-haul transport [6]. In both [4] and [5], hydrogen produced from water electrolysis with renewable electricity, known as green hydrogen, is considered the most critical hydrogen production process in the energy transition pathway. According to [4], to achieve net zero emissions by 2050, the global demand for hydrogen would increase from today's 95 million tons per year to 430 million tons by 2050, with 76% of the total being green hydrogen.

Despite its great importance to climate change mitigation, green hydrogen production only represented 0.1% of total production in 2022 [7]. Production cost reduction, along with investments in appropriate infrastructure, technological advancements, and effective public policies, are among the main steps needed to develop the global green hydrogen market [5]. Currently, the estimated levelized cost of producing green hydrogen (LCOH) varies from 4 to 12 USD per kilogram (USD/kg), up to 6 times more expensive than hydrogen produced from fossil fuels, also known as gray hydrogen [7]. Reducing these costs is the main challenge for green hydrogen in fulfilling its role in the energy transition. [8]

However, achieving competitiveness is complex since electrolysis is highly energy- and capital-intensive. Renewable electricity is the most significant single-cost component for on-site production of green hydrogen [9]. It has fallen sharply in recent years, with a reduction in the levelized cost of electricity (LCOE) of 89% for solar photovoltaics (PV) and 69% for onshore wind from 2010 to 2022 [10]. Further reductions are necessary for green hydrogen competitiveness [7]. The second most significant component is the investment cost of the electrolyzers [9], which mainly use alkaline or polymer exchange membrane (PEM) technologies [7]. Despite being mature technologies, further technology advancements are still expected in the long term, which could, along with economies of scale, reduce the cost of electrolysis facilities [9].

In the short term, alternative strategies are needed to achieve the economic feasibility of green hydrogen production projects. An optimal power supply strategy is essential to reduce the LCOH since it influences not only the electricity cost but also the electrolysis facility's operating hours, which allows a higher hydrogen production for the same investment in the electrolyzer. Higher utilization of the electrolyzer can be achieved, for example, with a power supply mix composed of large-scale hybrid wind and solar PV plants in regions with high capacity factors [9], or using the grid as a backup [7].

The competitiveness of green hydrogen also depends on certification requirements. For hydrogen to be considered green, renewable, or low carbon, it must follow a set of sustainability criteria defined either by voluntary certification systems or by regulation [11]. Those criteria are essential to guarantee the low carbon intensity of the hydrogen produced through the electrolysis process, as its emissions depend on the source of the electricity used. For example, considering the global average emission intensity of power, the hydrogen produced from water electrolysis would have an emission intensity similar to that produced through the coal gasification process [7]. One option to guarantee low carbon emissions is to install the electrolyzer in a region where the grid is already highly renewable. In this case, the electrolyzer could operate constantly and, thus, reduce the LCOH while maintaining a low carbon intensity.

In 2023, the European Union (EU) formally adopted a delegated act outlining detailed rules on the EU definition of renewable hydrogen [12]. For hydrogen to be considered as a Renewable Fuel of Non-Biological Origin (RFNBO), it must be produced with electricity either purchased from renewable generation assets or sourced from the grid if it has more than 90% of renewable generation [13]. The main criteria will be described in the next chapter. These rules will apply to domestic and international producers exporting renewable hydrogen to the EU [12].

Brazil has healthy prospects for producing, consuming, and exporting green hydrogen [14]. The Brazilian power grid is already highly renewable, with 93% of renewable generation in 2023 [15], and has a great potential to develop new renewable generation projects, with almost 30 GW of projects expected to come online until 2028 [16]. By the end of 2023, 35 companies had already announced the intention to develop hydrogen production projects in the Port of Pecém [17], located in the country's Northeast, focusing primarily on exports. These projects must comply with European regulations if they wish to export to the EU.

Projects in Brazil will need to develop strategies to produce cost-competitive green hydrogen while complying with European regulations. In this context, this study analyzes the levelized cost of hydrogen (LCOH) for projects in Brazil, considering certification requirements, project design, and restrictions related to hydrogen demand. A computational model was developed to perform these calculations for different case studies considering a theoretical project in Brazil, as will be explained later in this dissertation.

1.1 Objective and contributions summary

This dissertation measures the impact of different restrictions and project designs on the LCOH. An optimization model was developed to define the optimal characteristics of the hydrogen project, including renewable generation capacity composed of solar and wind resources, electrolyzer and storage capacity, and the amount of energy purchased from the grid as a backup. This dissertation includes four case studies to evaluate the impact on the LCOH of the connection to the grid to import electricity, the adoption of hydrogen storage, and the demand profile. The reference case considers a constant hydrogen demand to simulate a direct connection between the electrolyzer and an industrial facility that will consume hydrogen as a feedstock. An alternative case considers a flexible demand to simulate, for example, the existence of another feedstock that could complement green hydrogen, such as gray hydrogen, in existent ammonia production plants.

In this context, this dissertation's contributions are mainly a new economic analysis model with risk aversion metrics for hydrogen project developers to quantify and optimize the configuration of their projects, including the installed capacity of a hybrid power plant, electrolyzer, hydrogen storage, and compressor, considering restrictions related to certification and demand profile.

The structure of this dissertation is as follows. Section III will explore the criteria for RFNBO defined in European Union regulation and the risk for Brazilian projects of not complying with these rules. Section IV introduces the optimization model and how it differs from published models. Section V presents a comparative analysis of the results of each case study and a sensitivity analysis using realistic data from the Brazilian power system. Finally, Section VI summarizes the main conclusions of this work and highlights possible future extensions.

2
Challenges for Brazilian Projects in Meeting European RFNBO Regulations

In June 2023, the European Commission adopted a delegated act that complements the Renewable Energy Directive (EU) 2018/2001 and establishes the criteria for the characterization of renewable fuels of non-biological origin (RFNBO). For hydrogen to be considered RFNBO, it must follow the defined criteria. In this dissertation, the focus will be on the requirements defined for two energy supply strategies: dedicated off-grid renewable power generation plants and direct connection to the grid. [13]

One of the energy supply options for renewable hydrogen plants is a direct connection between the electrolyzer and renewable electricity installations. In this case, the project can export excess energy to the grid but not import energy to produce more hydrogen. The electricity consumed must come exclusively from non-biogenic renewable sources, including solar, wind, and hydroelectric, and the installation generating renewable energy must have come into operation no earlier than 36 months before the hydrogen production facility. [13]

Hydrogen producers can take electricity from the grid if the hydrogen plant is located in a bidding zone where the share of renewable electricity in the previous year exceeded 90%. In this case, the electrolyzer could operate almost constantly, with an operation hours limit defined by multiplying the number of hours in a year by the share of renewable generation in the bidding zone. The 90% threshold was established to guarantee at least a 70% reduction in the emissions intensity compared to the defined fossil-based reference, which is 94 kg CO_2/MJ [13].

Only a few countries already meet or are close to meeting this 90% threshold. According to [18], only 25 countries have a grid with more than 85% renewable share. As part of the list of countries with a high renewable share, Brazil has a competitive advantage in the international hydrogen market. In 2023, renewable energy represented 93% of Brazil's total electricity production [15]. Also, the Northeast, one of the four submarkets of the Brazilian power sector, reached a renewable share of over 99% [15] in the same year. The high renewable share allows hydrogen production projects in Brazil to use energy from the grid while also complying with European regulations, and thus increase the operation hours, reducing the LCOH.

However, in the long term, there are multiple risks to maintaining the high renewable share in the power matrix. One risk aspect is related to policies implemented or under discussion in Brazil, which set the country on track to increase energy sector emissions. Among these policies are the implementation of 8 GW of inflexible gas-fired thermal power plants under Law 14.182/2021 and the extension of coal-fired power plant contracts until 2040 under Law 14.299/2022. These policy measures, together with others under discussion, could increase the participation of fossil fuels in the Brazilian grid, thus jeopardizing Brazil's climate ambitions [14].

Besides the policy risk, climate change will also be a risk to the renewable share of the Brazilian power system. The grid is still heavily dependent on hydropower plants, having represented almost 70% of centralized generation in 2023 [15]. With the negative impacts of climate change expected on inflows [19], this energy source will contribute a smaller amount of energy to the system. Thus, fossil-based sources could replace part of the lost generation. To illustrate this issue: In 2021, which was the driest year in the last 91 years [20], the renewable share was 80%, a steep reduction compared to 2023 levels [15].

Both aspects risk the continuation of a high renewable share in the Brazilian power matrix. If the 90% threshold is not met, hydrogen production projects installed in the country would not be able to use the grid as a backup if they wish to meet European certification criteria. Consequently, Brazil will lose its competitive advantage over other exporters and will have a smaller participation in the hydrogen developing market. This risk can be mitigated by adopting a more holistic approach to power system expansion, incorporating the market potential for renewable fuels into system planning.

One of the goals of this dissertation was to assess the impact of this risk on the LCOH of Brazilian projects. Aside from this evaluation, other flexibility aspects that could impact LCOH are analyzed, such as hydrogen storage and demand profile. An optimization model was created to explore these aspects, as explained in the following section.

3
Mathematical Model

3.1
Nomenclature

Sets and Indices

T Set of hours defining the optimization horizon ($t \in T$ denotes a given hour in the study horizon).

Ω Set of scenarios ($\omega \in \Omega$ to denote a given scenario).

G Set of power generation assets ($i \in G$ to denote a given asset).

Random variables

$\pi^e_{t,\omega}$ Electricity spot price (USD/MWh).

$\mathbf{F}_{t,\omega,i}$ Capacity factors of each power generation asset.

Constants and parameters

P^H Hydrogen selling price (kUSD/kg).

R^H Hydrogen yield of the electrolysis plant (kg H2/MWh).

P^W Water price (kUSD/m^3).

R^W Water consumption rate (m^3/kg H2).

C^g_i Sum of annualized CAPEX and OPEX of each generation asset - i (USD/kW/year).

C^H Sum of annualized CAPEX and OPEX of the electrolyzer (USD/k-W/year).

C^{Hs} Sum of annualized CAPEX and OPEX of the hydrogen storage (kUS-D/kg/year).

C^{Hc} Sum of annualized CAPEX and OPEX of the hydrogen compressor (kUSD/kg/h/year).

C^I Network-access contract tariff to import energy from the grid - consumer (USD/kW.year).

C^E Network-access contract tariff to export energy to the grid - generator (USD/kW.year).

Q^H Maximum hourly hydrogen demand (kg/h).

S^H Maximum hydrogen storage capacity (kg).

R^{Hc} Electricity consumption of the hydrogen compressor (MWh/kg).

ϕ^e Penalty fee for lack of physical guarantee (USD/kWh).

α Auxiliary variable between 0 and 1 to define the hydrogen price.

δ Auxiliary variable applicable to the hydrogen deficit penalty.

Decision Variables

x_i^g Installed capacity of each generation asset - i (MW).

x^H Installed capacity of the electrolyzer (MW).

x^{Hc} Installed capacity of the hydrogen compressor (kg/h).

x^{Hs} Installed capacity of the hydrogen storage (kg).

q^I Network-access contract quantity for a consumer - importer of energy (MW).

q^E Network-access contract quantity for a generator - exporter of energy (MW).

$q^{\Delta_{EI}}$ Network-access contract quantity for a self-producer with the generation higher than load - net exporter of energy (MW).

q^H Fixed hourly hydrogen demand (kg/h).

$e_{t,\omega}^H$ Excess hydrogen produced, in addition to the fixed demand (kg/h).

$d_{t,\omega}^H$ Hydrogen deficit quantity (kg/h).

d_ω^e Energy deficit due to lack of physical guarantee (MWh).

$p_{t,\omega}^H$ Energy consumption of the electrolysis plant (MWh).

$p_{t,\omega}^N$ Energy exchanged with the network (MWh).

$p_{t,\omega}^c$ Energy curtailed (MWh).

$p_{t,\omega}^g$ Net generation (after curtailment) (MWh).

$p_{t,\omega}^{Hc}$ Energy consumption of the hydrogen compressor (MWh).

$f_{t,\omega}^{Hin}$ Hydrogen flow into the storage (kg/h).

$f_{t,\omega}^{Hout}$ Hydrogen flow out of the storage (kg/h).

$s_{t,\omega}^H$ Hydrogen stored at a given time (kg).

3.2
Model definition and Context

Mathematical models for optimizing hydrogen production projects have been developed in several studies, such as in [21], [22], [23], [24], [25], [26], [27] and [28]. A review of hydrogen production modeling, done by [29], recognizes a growing number of publications related to hydrogen, especially related to its production processes and supply chain. According to [29], the models developed for hydrogen process design are solved directly or by decomposition methods and use a single-stage investment approach. Also, the models often don't consider uncertainty and involve non-linear constraints, resulting in non-linear programs or simulation-based problems. Another relevant conclusion is that the most represented regions in case studies used in these models are Asia, North America, and Europe. The approach taken in this study is to use a linear programming model, solved via Benders decomposition, which considers uncertain electricity market prices and renewable generation, and to apply it in a case study in Brazil.

Studies have been carried out using a similar approach. In [24], an analytical framework was developed to optimize the size of a wind power plant to supply a hydrogen production facility, considering the variability in electricity prices and renewable power generation and a fixed price of the hydrogen contract. In [25], the commercial software Homer was used to determine the optimal capacity of a combined hydroelectric-photovoltaic power station located in Oman to maximize hydrogen production. In [26], the capacity of a hybrid wind and solar plant is optimized to minimize hydrogen production cost, using hourly meteorological data from China and considering a constant supply of hydrogen to a green methanol production facility. In [27], a model was developed to test the effect on hydrogen production cost and project design of a more flexible power supply requirement for hydrogen to be considered as renewable under European certification criteria. It uses a case study in Germany, which assumes a hybrid solar and wind power plant and uses the grid as a backup.

The model proposed in this dissertation also optimizes the hydrogen demand quantity variable, similar to the fixed demand defined in [26] with a fixed price defined in [24]. The impact of the certification requirement on the power supply is analyzed, as in [27]. Still, a stochastic model is applied to the uncertainty considered, unlike the perfect foresight assumption taken in [27]. In addition, the optimal usage of the grid as a backup is defined, unlike [25], and the hydrogen storage is also optimized.

The optimization model developed within the framework of this study has the objective of maximizing the net revenue of a hydrogen project, which includes a hybrid power generation plant composed of wind and solar power, an electrolysis facility, hydrogen storage, and the connection to the grid, as shown in Figure 3.1. The model defines the optimal installed capacity of the wind and solar power plants, the hydrogen storage and compressor, and the optimal network access contracts quantities to exchange energy with the grid. The installed capacity of the assets is modeled as a continuous variable, meaning it does not account for whether the equipment is produced in a modular manner.

The costs of this project include the investment and operational costs of the renewable power plants, the hydrogen storage and compressor and the electrolyzer, the cost of the network access contract, the cost of buying energy from the grid, the water costs, and the deficit penalties of not meeting the fixed hydrogen demand or of importing more power than allowed by the country's regulation.

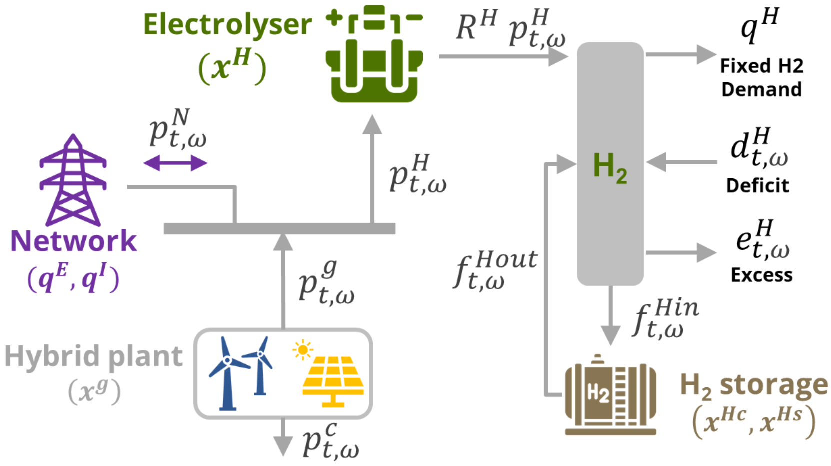

Figure 3.1: Illustrative design of the modeled project

Regarding project revenue, the primary source of income is the hydrogen sold. A hydrogen supply contract is considered with a fixed demand quantity and a fixed price. The hydrogen produced in excess of the contracted quantity can be sold at a price that can be at most the price defined in the contract and is defined by the term $P^H(1-\alpha)$, with a parameter α that will be explained next. On the other hand, if the quantity of hydrogen produced is insufficient to meet the fixed demand, a deficit penalty must be paid, which is modeled by the term $P^H(1+\delta\alpha)$.

The price terms were modeled as changeable variables to allow the representation of different business models. If α equals zero, the excess and the deficit will have the same price as the fixed demand. This case simulates a completely flexible hydrogen production, which could occur, for example, in the insertion of hydrogen into natural gas pipelines or in the existence of another feedstock that could complement green hydrogen when it is unavailable. On the other hand, if α is equal to one, there is no selling price for the excess hydrogen produced, and the project owner would need to pay a defined deficit penalty. This design is equivalent to having a constant hydrogen demand, for example, in a case where the hydrogen facility is directly connected to a steel plant using the direct reduction of iron (DRI) process with hydrogen as the only reducing agent. In this case, a hydrogen shortage would force the plant to stop operating, and the operation would not absorb the hydrogen excess.

The net revenue, calculated as the total revenues minus the costs, is represented by equation (3-1). The revenue depends on the hydrogen produced and the surplus energy exported to the grid p^N_t. Both these variables depend on the energy generated with the hybrid plant, which varies according to the wind and solar power generation scenarios included in the model. The investment decision, the network-access contract, and the hydrogen supply contract remain unchanged across the renewable generation scenarios, but the plant operation varies. In addition to renewable generation, scenarios for the prices to sell and buy energy from the grid in the spot market are also considered.

$$
\begin{aligned}
R_\omega = -\Bigg(\left(\sum_{i=1}^{G} C_i^g x_i^g \right) + C^H x^H + C^I q^I + C^E q^{\Delta_{EI}} \\
+ C^{Hs} x^{Hs} + C^{Hc} x^{Hc} \Bigg) + \sum_{t=1}^{T} \left(P^H q^H \right) \\
+ \sum_{t=1}^{T} \Big[P^H \left((1-\alpha) e_{t,\omega}^H - (1+\delta\alpha) d_{t,\omega}^H \right) \\
- P^W R^W R^H p_{t,\omega}^H - \pi_{t,\omega}^e p_{t,\omega}^N \Big] - \phi^e d_\omega^e \quad \text{(3-1)}
\end{aligned}
$$

The optimization model defines the project that maximizes net revenue, considering a set of assumptions. The model calculates the optimal installed capacity of the hybrid power plant, the electrolyzer, the hydrogen storage and compressor, the network access contracts to import and export energy to the grid, and the fixed hydrogen demand quantity. The model also operates the system hourly, indicating the electricity and hydrogen flows.

3.3
Constraints

3.3.1
Renewable generation

As explained, scenarios of renewable power generation were considered due to the variability of these resources. The actual energy generated by the hybrid plant depends not only on the generation profiles $(F_{t,\omega,g})$ but also on the installed capacity defined by the model (x_i^g) and the amount curtailed at each hour, which the model also defines. The constraint created is in Equation (3-2).

$$
p_{t,\omega}^g = \sum_{i=1}^{G} (F_{t,\omega,i}\ x_i^g) - p_{t,\omega}^c, \qquad \forall\ t, \omega \qquad \text{(3-2)}
$$

3.3.2
Hydrogen Demand

The project must meet a fixed hydrogen hourly demand q_H, which the model defines. This demand must be smaller than the maximum demand chosen. The object of modeling the demand as a decision variable is to allow the decision of not building the hydrogen project if the project doesn't reach economic feasibility. The constraint created is in Equation (3-3).

$$
0 \leq q^H \leq Q^H \qquad \text{(3-3)}
$$

3.3.2.1
Energy balances

In the model, there are two energy balances, one for electricity and the other for hydrogen. Related to electricity, the input is the net power generated by the hybrid plant ($p^g_{t,\omega}$) and the output is the energy used by the electrolyzer ($p^H_{t,\omega}$), which is limited to its installed capacity, and the hydrogen compressor ($p^{Hc}_{t,\omega}$), which is defined by the hydrogen inflow ($f^{Hin}_{t,\omega}$). The variable ($p^N_{t,\omega}$) denotes the energy exchanges with the grid, with a positive sign to import energy and a negative sign to export energy.

$$p^g_{t,\omega} - p^H_{t,\omega} - p^{Hc}_{t,\omega} + p^N_{t,\omega} = 0, \qquad \forall\ t,\omega \tag{3-4}$$

$$p^H_{t,\omega} \leq x^H, \qquad \forall\ t,\omega \tag{3-5}$$

$$p^{Hc}_{t,\omega} = R^{Hc} f^{Hin}_{t,\omega}, \qquad \forall\ t,\omega \tag{3-6}$$

Regarding the hydrogen, the input is the amount of hydrogen produced by the electrolyzer ($R^H p^H_{t,\omega}$) plus the hydrogen extracted from the storage facility ($f^{Hout}_{t,\omega}$). At the same time, the outputs are the fixed demand (q^H), the excess hydrogen produced ($e^H_{t,\omega}$), and the hydrogen inserted into the storage facility ($f^{Hin}_{t,\omega}$). If the hydrogen produced is less than the fixed demand, the deficit variable is activated ($d^H_{t,\omega}$).

In addition, an energy balance is considered for hydrogen storage. The amount of hydrogen stored at time t equals the hydrogen stored at time (t-1) plus the hydrogen inserted minus the hydrogen removed. The quantity of hydrogen stored is limited to the size of the tank installed, while the hydrogen flows are limited to the installed capacity of the compressor.

$$R^H p^H_{t,\omega} + f^{Hout}_{t,\omega} + d^H_{t,\omega} = f^{Hin}_{t,\omega} + e^H_{t,\omega} + q^H, \qquad \forall\ t,\omega \tag{3-7}$$

$$s^H_{t,\omega} = s^H_{t-1,\omega} + f^{Hin}_{t,\omega} - f^{Hout}_{t,\omega}, \qquad \forall\ t,\omega \tag{3-8}$$

$$s^H_{t,\omega} \leq x^{Hs}, \qquad \forall\ t,\omega \tag{3-9}$$

$$f^{Hin}_{t,\omega} \leq x^{Hc}, \qquad \forall\ t,\omega \tag{3-10}$$

$$f^{Hout}_{t,\omega} \leq x^{Hc}, \qquad \forall\ t,\omega \tag{3-11}$$

3.3.2.2
Grid Usage

An additional cost to the hydrogen project is related to using the transmission assets when connecting to the grid. In Brazil, which was the country chosen for the case studies, for power generation plants to have access to the transmission system, a contract must be made with the National System Operator (ONS) defining the amount of usage of the transmission system (MUST, in Portuguese). The MUST is the maximum value between the amount contracted and verified by an electrical power meter in a given connection point. The charge to use the transmission system equals the multiplication between the MUST and a given location's transmission tariff (TUST, in Portuguese). [30]

For a consumer, there is a MUST for peak and off-peak hours. The peak and off-peak times depend on the concession area of the plant's location. Thus, the charge to use the transmission system is the sum of the MUST off-peak multiplied by the transmission tariff off-peak and the MUST peak multiplied by the TUST peak. [30] To simplify, in this dissertation it was assumed that the TUST off-peak and TUST peak would be equal, so there is no incentive to define a MUST off-peak different from the MUST peak, and the formulation would then consider only one variable for the MUST of the consumer.

The hydrogen project considered in this study, being both a consumer and a generator, would be subject to both transmission charges. However, in case of a single project that is both a consumer and a generator, to calculate the transmission charge as a generator, the TUST is only applied to the additional transmission usage compared to the MUST of consumption.

The MUST is a decision variable and limits the amount of energy imported and exported. The constraints created are shown next.

$$-q^E \leq p^N_{t,\omega} \leq q^I, \quad \forall\ t,\omega \tag{3-12}$$

$$q^{\Delta_{EI}} \geq q^E - q^I \tag{3-13}$$

$$q^{\Delta_{EI}}, q^I, q^E \geq 0 \tag{3-14}$$

$$\tag{3-15}$$

Finally, an additional constraint was included to limit the consumer MUST. The MUST is limited by the size of the electrolyzer to avoid energy price arbitrage and to increase the performance of the model. The constraint, applied to the first stage problem, is the following:

$$q^I \leq x^H \tag{3-16}$$

3.3.3 Firm Energy Deficit

In the Brazilian Power Sector regulation, every new load must be 100% covered by contracts. The load coverage is verified by the Electric Energy Trading Chamber (Câmara de Comercialização de Energia Elétrica - CCEE) every month, using a 12-month moving average: the load's 12-month moving average is compared to the 12-month moving average volumes produced by built power generation plants or bought through PPAs. Thus, the penalty is an additional cost to the hydrogen project, calculated by the penalty fee multiplied by the difference between the amount consumed from the grid in the 12 months and the amount exported to the grid; if higher than zero [31].

$$d^e_\omega \geq \sum_{t=1}^{T} p^N_{t,\omega}, \quad \forall\ \omega \tag{3-17}$$

$$d^e_\omega \geq 0, \quad \forall\ \omega \tag{3-18}$$

3.4
Formulation of the Optimization Model

The model is as follows:

$$\max_{\mathbf{x},\mathbf{q}\geq 0} -\left(\left(\sum_{i=1}^{G} C_i^g x_i^g\right) + C^H x^H + C^I q^I + C^E q^{\Delta_{EI}} + C^{Hs} x^{Hs} + C^{Hc} x^{Hc}\right) + \sum_{1}^{T} \left(P^H q^H\right) + E_\omega[Q(\mathbf{x},\mathbf{q};\omega)] \quad \text{(3-19)}$$

st.

$$x^H \leq R^H Q^H$$
$$q^I \leq x^H$$
$$q^{\Delta_{EI}} \geq q^E - q^I$$
$$q^H \leq Q^H$$
$$x^{Hc} \leq Q^H$$
$$x^{Hs} \leq S^H$$

Where

$$Q(\cdot;\omega) = \max_{e^H, s^H, \mathbf{f}, \mathbf{d}, \mathbf{p}} \sum_{t=1}^{T} \Big[-\pi_{t,\omega}^e p_{t,\omega}^N + P^H(1-\alpha) e_{t,\omega}^H - P^H(1+\delta\alpha) d_{t,\omega}^H - P^W R^W R^H p_{t,\omega}^H \Big] - \phi^e d_\omega^e \quad \text{(3-20)}$$

st.

$$
\begin{aligned}
& p^g_{t,\omega} = \sum_{i=1}^{G} (F_{t,\omega,i}\ x^g_i) - p^c_{t,\omega}, && \forall\ t,\omega \\
& p^g_{t,\omega} - p^H_{t,\omega} - p^{Hc}_{t,\omega} + p^N_{t,\omega} = 0, && \forall\ t,\omega \\
& p^H_{t,\omega} \leq x^H, && \forall\ t,\omega \\
& p^{Hc}_{t,\omega} = R^{Hc} f^{Hin}_{t,\omega}, && \forall\ t,\omega \\
& R^H p^H_{t,\omega} + f^{Hout}_{t,\omega} + d^H_{t,\omega} = f^{Hin}_{t,\omega} + e^H_{t,\omega} + q^H, && \forall\ t,\omega \\
& s^H_{t,\omega} = s^H_{t-1,\omega} + f^{Hin}_{t,\omega} - f^{Hout}_{t,\omega}, && \forall\ t,\omega \\
& s^H_{t,\omega} \leq x^{Hs}, && \forall\ t,\omega \\
& f^{Hin}_{t,\omega} \leq x^{Hc}, && \forall\ t,\omega \\
& f^{Hout}_{t,\omega} \leq x^{Hc}, && \forall\ t,\omega \\
& -q^E \leq p^N_{t,\omega} \leq q^I, && \forall\ t,\omega \\
& d^e_\omega \geq \sum_{t=1}^{T} p^N_{t,\omega}, && \forall\ \omega \\
& e^H_{t,\omega}, \mathbf{d}_\omega, \mathbf{p}_{t,\omega}, \mathbf{f}_{t,\omega} \geq 0, && \forall\ t,\omega
\end{aligned}
$$

The model is implemented in Julia language (JuMP [32]) and solved by HiGHs [33], using the SDDP.jl package [34] for the Benders Decomposition.

3.5 Risk Analysis

Using the SDDP.jl package, a risk measure was also implemented in this model to account for risk-averse investors. The risk measure implemented is a convex combination between the Conditional Value at Risk (CVaR) and the expected value of the net revenue. CVaR, as stated in [35], can be defined as the conditioned expectation of the revenue left-side worst distribution scenarios. In this case, the CVaR will be the average revenue of the scenarios below a given β quantile. Revenue will vary mainly based on the power generation and spot prices. CVaR is added to the objective function, as described in (3-21). The variable λ can vary from 0 to 1, to give a greater importance to the expected value of the objective function or the risk measure, respectively.

$$\lambda * CVaR(\beta)[R_\omega] + (1-\lambda) * E[R_\omega] \tag{3-21}$$

4
Results

4.1
Case Studies

Four case studies were used to calculate the levelized cost of hydrogen in Brazil for different configurations of the project design. The main differences between the cases are the use of energy from the grid as a backup, the deployment of hydrogen storage, and the adoption of a flexible demand. The case studies have the following characteristics:

– **Reference Case**: The electrolyzer is directly connected to the installed hybrid power plant and the grid can only be used to export electricity produced in excess. This case was considered a Reference Case since it is a configuration accepted in the European Union without additional risks or criteria. The hydrogen produced meets only the fixed demand with no possibility of selling the hydrogen produced in excess and with a penalty fee of three times the price settled in contract ($\alpha = 1$ and $\delta = 2$). Finally, a risk averse investor was considered, with $\lambda = 0.9$.

– **Case Study 2**: Adds only the possibility of importing electricity from the grid to the reference case. This design could be accepted in the European certification in case of a bidding zone with a renewable share in electricity generation higher than 90%.

– **Case Study 3**: Adds the possibility of storing hydrogen to the reference case. This case would also be accepted without restrictions in the European Union but would increase the total investment cost of the hydrogen project.

– **Case Study 4**: Changes the profile of the demand of the reference case to be a flexible demand, where excess hydrogen is sold at the same price as the contract price and deficit cost are also equal to the contract price ($\alpha = 0$).

This dissertation includes also sensitivity analyses based on the reference case in addition to these four main cases. The objective of the analyses was to verify the impact of defined variables on the design of the hydrogen project. The variables chosen were the hydrogen price defined in the contract and the investor's level of risk aversion.

For the case studies, a set of assumptions was structured. Table 4.1 shows the economic and technical assumptions considered for the electrolyser, the wind and solar power plants, the hydrogen compressor and the hydrogen storage tank. Most assumptions were taken from international references, except the water cost, which was taken from a local reference for the selected location of the project, as will be explained next. In addition, a maximum hydrogen demand of 1000 kg H_2/h was assumed to limit the size of the optimization problem. Also, it was assumed an internal rate of return of 12%

Parameter	Value	Unit	Reference
Wind power - CAPEX	1400	USD/kW	[36]
Wind power - annual OPEX	2	% of CAPEX	[36]
Wind power - Lifespan	20	years	[36]
Solar power - CAPEX	1000	USD/kW	[36]
Solar power - annual OPEX	1	% of CAPEX	[36]
Solar power - Lifespan	30	years	[36]
Electrolyzer - CAPEX	943	USD/kW	[36]
Electrolyzer - annual OPEX	1.5	% of CAPEX	[36]
Electrolyzer - Lifespan	25	years	[36]
Electrolyzer - Conversion rate	57	kWh/kg H_2	[36]
Water Cost	2.97	USD/m^3	[37]
Water Requirement	17.5	m^3/ton H_2	[38]
H_2 Compressor - CAPEX	5.34	kUSD/kg/h	[39]
H_2 Compressor - Demand	1.49	kWh/kg	[39]
H_2 Compressor - Lifetime	15	years	[39]
H_2 Compressor - annual OPEX	4	% of CAPEX	[39]
H_2 Storage Tank - CAPEX	950	USD/kg	[40]
H_2 Storage Tank - annual OPEX	0	% of CAPEX	[40]
H_2 Storage Tank - Lifetime	25	years	[41]

Table 4.1: Assumptions for the case studies

and a transmission tariff of 31 USD/kW to export and 21 USD/kW to import, based on average values for Brazil.

A set of assumptions was considered to simplify the analysis. Firstly, electrolyser degradation was not taken into account, resulting in a constant efficiency over its operational lifetime. Secondly, no unavailability rate was considered for the electrolyser, allowing it to operate 100% of the time. Finally, no price was considered for the oxygen produced.

Within the assumptions, scenarios for the random variables are also included. 100 renewable generation scenarios were created for a specific location in the state of Rio Grande do Norte, in the northeast of Brazil, using the Time Series Lab software [42], developed by the Brazilian company PSR [43]. The location was chosen to achieve high capacity factors both for wind and solar power. The selected area's average wind and solar power capacity factors are shown in Figure 4.1 and Figure 4.2, respectively.

Electricity spot market prices were also generated. In Brazil, the spot price is defined as the marginal operating cost of the system, which is a by-product of the dispatch schedule, determined by the National System Operator to minimize the expected value of the total operating expenses of the system [44]. In this dissertation, 100 scenarios of electricity spot prices were produced using the computational tools SDDP [45] and OPTGEN [46], also developed by PSR, which calculate the optimal operation of the power system and the optimal expansion plan of the system, respectively.

The case studies and the sensitivity analysis results are in the following subsections. A detailed description of the Reference Case will be given in the following subsection, while for the other case studies only the results for the

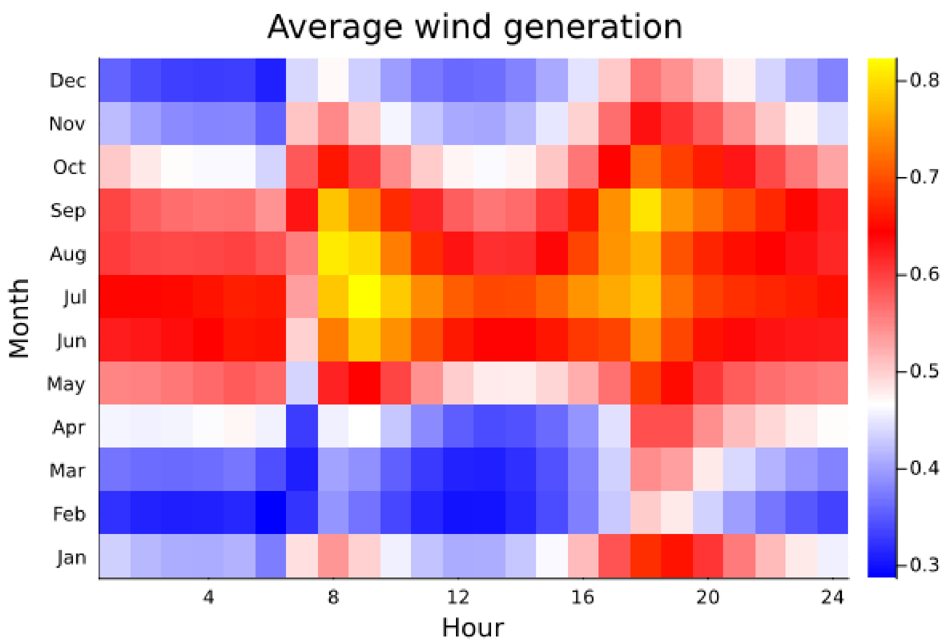

Figure 4.1: Average Capacity Factor of the Wind Power Plant Selected

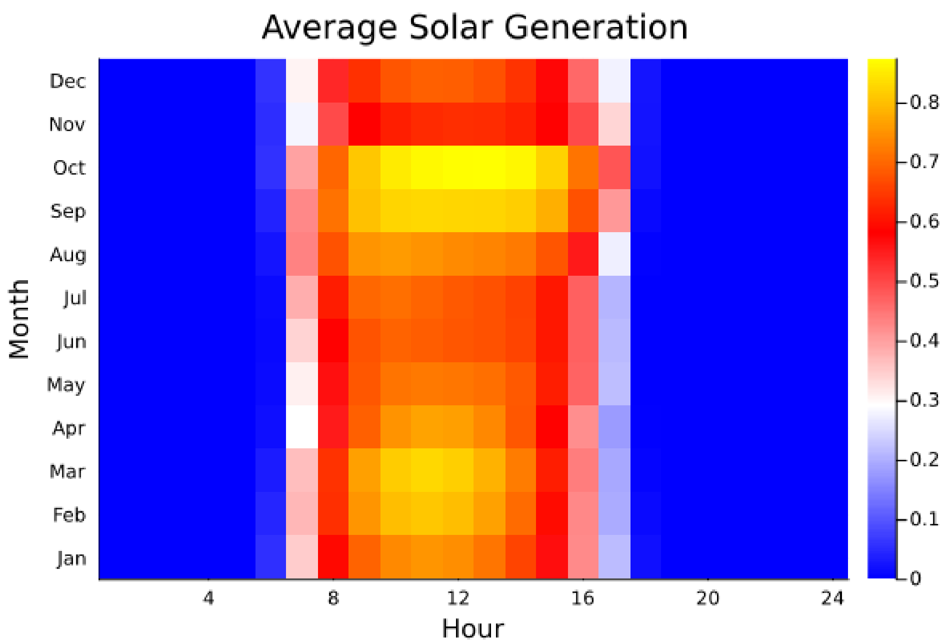

Figure 4.2: Average Capacity Factor of the Solar Power Plant Selected

most important variables will be shown, including hydrogen deficit, utilization factor of the electrolyser, LCOH, installed capacity of the hybrid power plants and net revenue.

4.1.1 Results of the Reference Case

The reference case considers an off-grid hybrid power generation plant directly connected to the electrolyzer, using the grid only to export excess electricity produced. In this case, there is a constant demand for hydrogen at a fixed price, a penalty for deficit, and an inability to take advantage of hydrogen produced in excess. The case simulates an industrial plant that must operate constantly and needs a constant supply of its inputs, such as a steel production plant.

This configuration leads to an LCOH of 6.4 USD/kg. The model chooses to install a hybrid power plant, composed of 138 MW of wind and 40 MW of solar energy, to supply a 57 MW electrolyzer that will produce enough hydrogen to meet a fixed demand of 1000 kg / h. A network-access contract for a generator of 44 MW is also adopted to export excess energy produced.

Unlike the investments made, the plant operation depends on the scenarios considered for the capacity factor of renewables and short-term energy prices. The scenarios influence all variables in the energy balances, including power generation, energy exported, electrolyzer consumption, and curtailment, among other variables. The variation of these variables throughout the year with the scenarios is shown in Figure 4.3.

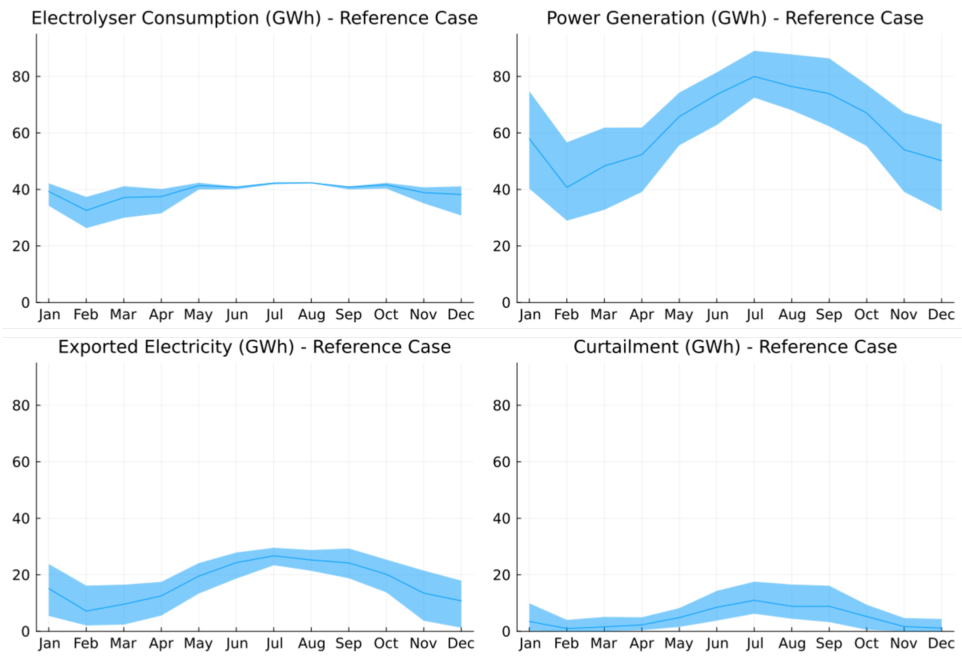

Figure 4.3: Energy Balance Variable throughout the year (GWh)

Variability in project operation also impacts net revenue. The main variables affected are the hydrogen deficit, the revenue from excess energy sold, and the water costs. The impact of water costs and excess energy sales is smaller than that of hydrogen deficit, as shown in Figure 4.4. The hydrogen deficit significantly impacts the net revenue since the deficit penalty is three times the price of the hydrogen sale. Even at this price, the deficit penalty is explored to reduce the installed capacity of the hybrid plant necessary to meet a fixed demand for hydrogen.

4.2 Comparative Analysis between case studies

The other case studies chosen were built based on the reference case, but increase the flexibility of the project. In Case Study 2 the electrolyzer

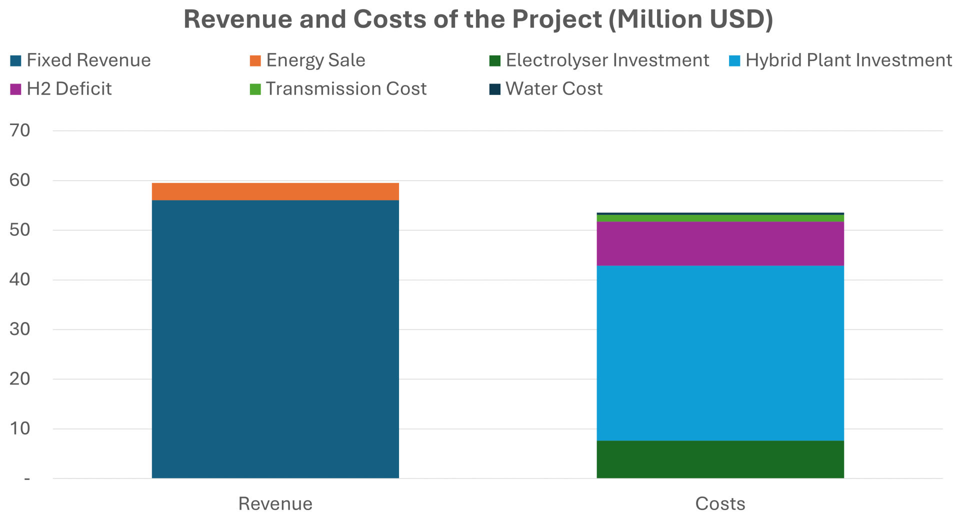

Figure 4.4: Revenue and Costs Composition of the Reference Case (Million USD)

can consume energy from the grid as a backup. This arrangement allows the electrolyzer to operate almost constantly, achieving a utilization factor of 99.9%, while the reference case's utilization factor was close to 94.7%. In Case Study 3 the additional flexibility is achieved with a hydrogen storage facility, which allows the reduction of 46% in deficit costs. Finally, in Case Study 4, a flexible demand is considered, which allows the electrolyzer operation to be closer to the profile of the renewable power plants.

These new arrangements change the configuration of the power generation plants installed. In the Reference Case, a 179 MW hybrid power plant was installed, composed of 77% wind power and 23% solar power. In contrast, Case Study 2 involved the installation of only a 116 MW wind power plant. The grid effectively complemented the wind power generation, eliminating the need for an additional solar power plant. In Case Study 3, a 147 MW hybrid plant was installed, composed by 66% wind power and 34% solar power. Hydrogen storage complemented the instant hydrogen production, enabling the installation of a smaller plant. Finally, in Case Study 4, an 84 MW hybrid plant, composed of almost 98% wind power, was installed. Flexible demand allows for a steeper generation capacity reduction due to the lower deficit costs.

The additional flexibility also impacts the net revenue of each project in the scenarios modeled. The Cumulative Probability Distribution of the unitary net revenue of each Case Study is in Figure 4.5. As can be seen, the Reference Case and Case Study 3 follow a similar net revenue profile, while Case Studies 2 and 4 result in a more stable revenue. In Case Study 2, grid imports reduce the project's exposure to renewable generation variability. In contrast, in Case Study 4, the reduced deficit penalty minimizes the impact of renewable generation variability on total project cost.

The changes in net revenue values and patterns determine the LCOH obtained. While the LCOH of the Reference Case is USD 6.4/kg, Case Studies 2, 3, and 4 reduce the LCOH to USD 4/kg, USD 6.1 /kg, and USD 4.3 /kg, respectively. In Case Study 2, the energy imported from the grid allows the constant production of hydrogen for reduced costs due to the low spot prices

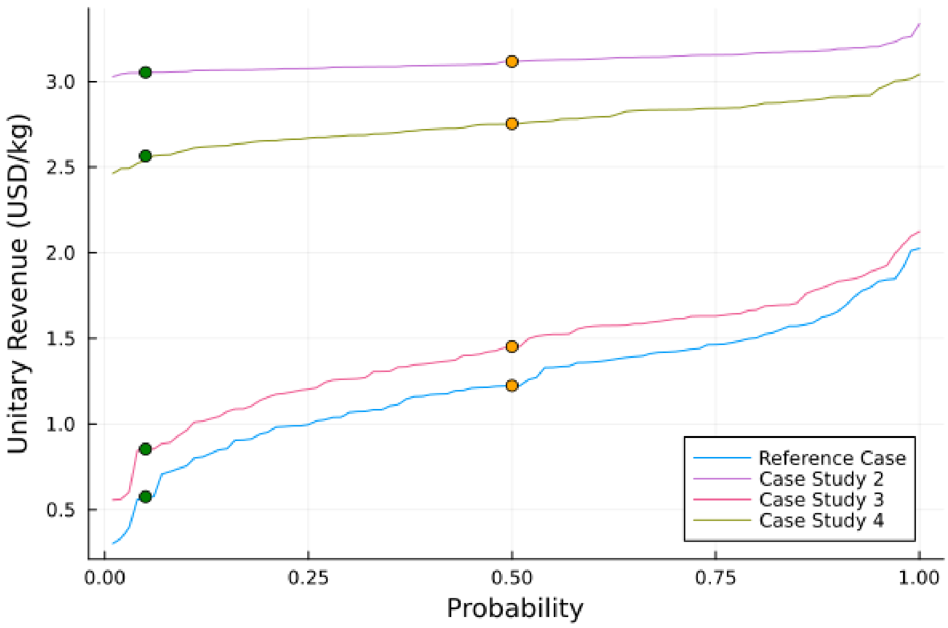

Figure 4.5: Unitary net revenue of each Case Study

projected for the future of the Brazilian market, reducing deficit costs by 99%. On the other hand, in Case Study 3, investments are needed in hydrogen storage and compressor capacity to provide the intended flexibility and the hydrogen supply contract is reduced to allow the electrolyzer to produce hydrogen in excess that can be stored. In Case Study 4, the reduction of costs with investments greatly impacts the LCOH. Still, the reduction of 27% in hydrogen production compared to Case Study 2 impacts the primary source of revenue, which makes the LCOH of Case Study 4 higher than the one from Case Study 2.

For comparison, a recent BloombergNEF analysis [47] points out that green hydrogen produced in Brazil would cost above USD 4/kg. Green hydrogen is still more expensive than the hydrogen produced through the steam reform of natural gas, also known as gray hydrogen. In Brazil, using an average natural gas price of 13.6 USD/MMBTU, as considered in the projection made by [48], the gray hydrogen production cost would be close to 2.5 USD/kg, considering assumptions from [49].

Considering the lowest cost of green hydrogen obtained, the price gap between green and gray remains at a minimum of 60%. A carbon price of around 125 USD/ton CO_2 would be necessary to achieve break-even. In 2024, the average global price of carbon, considering carbon market and carbon tax mechanisms, was close to 32 USD / ton CO_2 and only four countries achieved a carbon price higher than 125 USD/ton CO_2 [50]. In conclusion, even if Brazil had a carbon market, green hydrogen most likely would not be competitive compared to gray hydrogen, considering today's prices.

4.3
Sensitivity Analysis

Based on the reference case, two sensitivity analyses were made. The first considers the impact of the hydrogen price on the project design, and the second evaluates the impact of the investor's risk aversion.

The hydrogen price has a relevant impact on the project's feasibility since it determines the main source of revenue. If the price is too small, the project could become infeasible and, thus, it would not be implemented. On the other hand, if prices are higher, the project could install a higher capacity of the hybrid plant to reduce deficit costs and increase revenue with the excess electricity sold. The results are in Figure 4.6

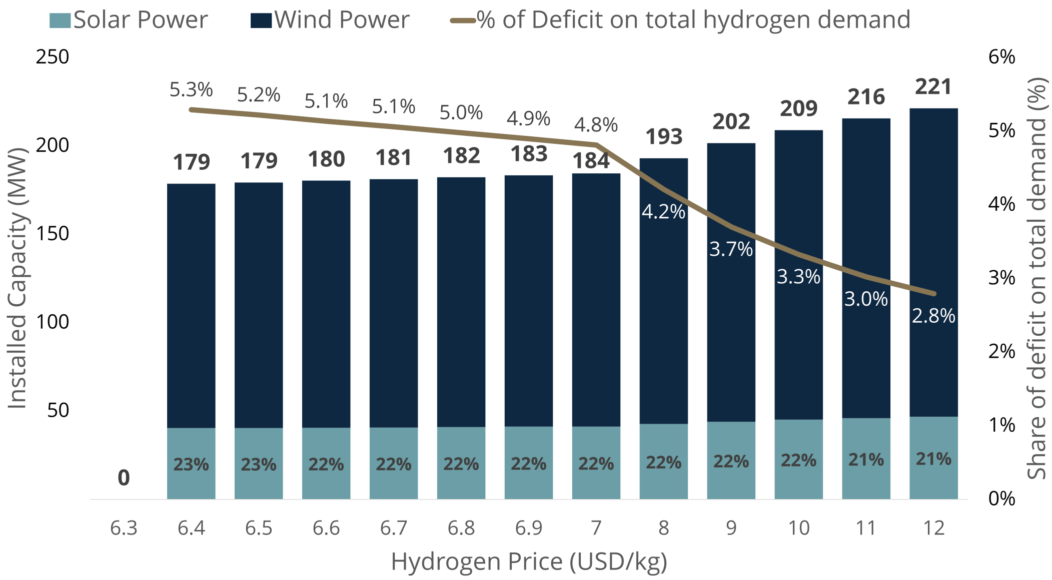

Figure 4.6: Installed Capacity and Deficit Variation with Hydrogen Selling Price

The risk aversion impacts not only LCOH but also renewable power generation. As investors become more risk averse, the capacity of the hybrid plant related to the electrolyzer increases to reduce risk related to renewable generation and deficit. The additional capacity increases investment costs, which results in a higher LCOH, as shown in Figure 4.7. The risk aversion also has an impact on deficit costs. The more risk-averse case has an average deficit cost 22% smaller than the less risk-averse case.

Due to the hydrogen market's low development level, a high risk aversion was adopted as the reference value. As shown in the sensitivity analysis, this assumption has a relevant impact on the high LCOH value obtained in the reference case. Measures to reduce the investor's perceived risk could reduce production costs.

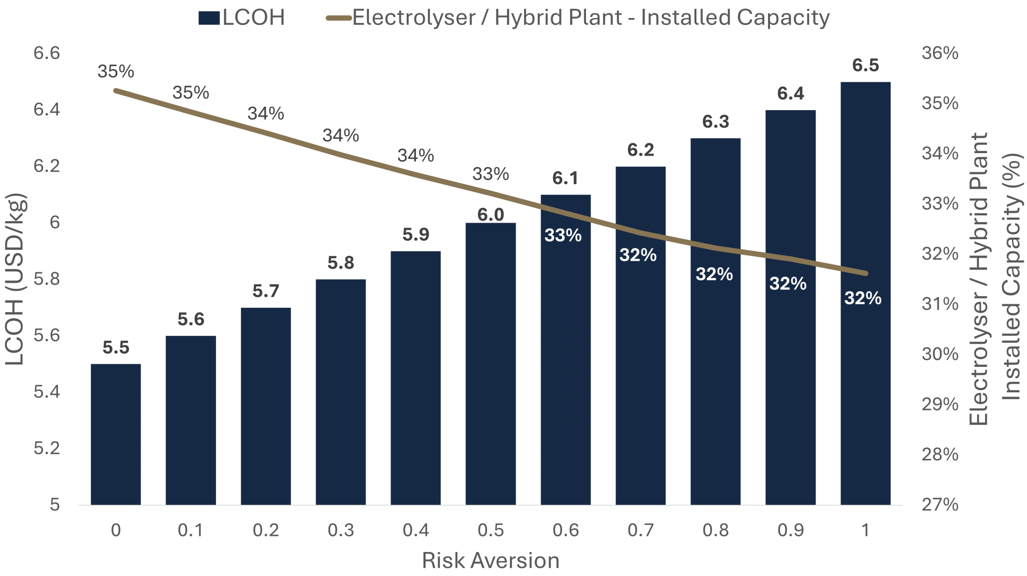

Figure 4.7: LCOH and Generation Capacity Variation with Risk Aversion

5
Conclusion

Despite the relevant role of green hydrogen in the pathway to net zero, its market is still developing, mainly due to its high production cost compared with gray hydrogen. Technology developments and economies of scale will be essential measures in the medium to long term to achieve break-even costs. However, in the short term, the reduction of costs can still be achieved through selecting locations with optimal renewable capacity factors and optimizing the electricity supply strategy, considering the grid as a backup, to achieve a cheaper and more stable electricity supply. Other aspects can help reduce costs, such as demand flexibility, reduction of perceived risks, and the implementation of hydrogen storage.

An optimization model was developed and implemented in Julia programming language to test and analyze the impact of these aspects on hydrogen production costs. The model optimizes the electricity supply portfolio, the installed capacity of the electrolyzer and the hydrogen storage, the transmission usage, the fixed hydrogen demand, and the operation of the hydrogen production plant. The model was used to assess the impact of multiple variables on the economic viability of a hypothetical hydrogen project, including the possibility of using the grid as a backup, hydrogen storage, demand flexibility, risk aversion, and hydrogen price.

As shown in the previous chapter, using the grid as a backup had the most relevant impact on the LCOH between the case studies adopted. The LCOH decreased from 6.4 USD/kg of the reference case to 4 USD/kg. Considering the economic aspect, this option would be preferable for hydrogen projects in Brazil. However, this option might not be available in the long term for projects seeking to export to the European Union.

The expansion of the Brazilian electricity sector brings with it risks for compliance with European regulations. The Brazilian grid currently has a renewable share in energy generation that can exceed 90%, the threshold defined by European regulation. However, this share could decrease in the future due to policies that subsidize fossil fuels and the impacts of climate change on hydropower generation, the main power generation source in the Brazilian matrix. It's crucial to manage these risks effectively to ensure the continued viability of Brazilian hydrogen projects in the international market.

Beyond utilizing the grid as a backup, additional flexibility mechanisms can help lower LCOH, even if their impact is relatively modest. The mechanisms evaluated in this dissertation were hydrogen storage, demand flexibility, and risk aversion. The most effective measure was the demand flexibility, but this option has barriers to its adoption since most hydrogen applications require a constant supply. Projects could adopt hydrogen storage to reduce the deficit and the installed capacity of the optimal generation facility. LCOH also decreased proportionally to the investor perceived risks, with a 0.01 USD/kg change for every 0.1 change in the λ. Flexibility and risk reduction measures also have an impact on hydrogen production costs.

In conclusion, Brazil's potential in the international hydrogen market could be significant. However, this potential may not be fully realized due to the risks associated with the Brazilian grid maintaining its high renewable share. To mitigate these risks, a comprehensive approach to the expansion and operation planning of the Brazilian power system is crucial. This approach should consider the system's impact on the renewable fuels market. Even without using the grid as backup, Brazilian hydrogen projects can still succeed by adopting other flexibility and risk aversion methods to reduce the LCOH and maintain a competitive position in the international hydrogen market.

The model developed can be improved further through research. The system design could include a battery energy storage system to allow the comparison between a hydrogen storage and electricity storage. Also, the project feasibility analysis can be further improved by including in the model the effect of taxes and charges, financing conditions, and transport to the final consumer.

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