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# Assessing the impacts of low-carbon intensity hydrogen integration in oil refineries

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ABSTRACT

This paper evaluates the potential impacts of introducing low-carbon intensity hydrogen technologies in two oil refineries with different complexity levels, emphasizing the role of hydrogen production in reducing $CO_2$ emissions. The novelty of this work lies in three key aspects: Comprehensive system analysis of refinery complexity using real site data, integration of low-carbon Hydrogen technologies, long-term and short-term strategies. Two Colombian refineries serve as case studies, with technological solutions adapted to their complexity levels. The methodology involves evaluating different options for hydrogen production, accounting for improvement in technological efficiency over time.

The refinery systems were evaluated in a cost-optimization model built in Linny-r. Three different scenarios were considered, Business-As-Usual (BAU), high, and low-ambitions decarbonization scenarios, focusing on the time horizons of 2030 and 2050.

When comparing the two case studies, the preferred decarbonization strategy for both facilities involves the substitution of SMR technology with water electrolyzers powered by renewable electricity. Post-2030, biomass-based hydrogen technology is still a costly alternative; however, to achieve $CO_2$ neutrality, negative emissions storage of biogenic $CO_2$ emerges as an achievable alternative.

Our results indicate the achievability of $CO_2$ reduction objectives in both refineries. Our results show that achieving long-term $CO_2$ neutrality requires both refineries to increase renewable electricity production by 5 to 6 times for powering water electrolyzers, steam production by 2 to 2.5 times for $CO_2$ capture, and supply of dry biomass by 2.6 to 4.5 kt/d.

The two most significant factors influencing the refining net margin in the decarbonization scenarios are primarily the $CO_2$ and the renewable electricity prices. The short-term horizon emerges as the pivotal period, particularly within the high-ambition decarbonization scenarios. In this context, the medium complexity refinery demonstrates economic viability until a $CO_2$ price of 140 €/t $CO_2$, while the high complexity refinery endures up to 205 €/t $CO_2$.

The high complexity refinery is better prepared to face the challenges of decarbonization and the impacts generated on the refining margin. Compared to the BAU scenario, the high complexity refinery shows a negative impact on the net margin that corresponds to a 40 % and 5 % reduction in the short and long term, respectively. Meanwhile, for the medium complexity refinery, the impact on net margin amounts to a 52 % reduction in the short term and a 27 % improvement in the long term.

Furthermore, our research highlights the significant potential for reducing $CO_2$ emissions by fully eliminating the use of refinery gas as fuel, providing alternative applications for it beyond combustion.

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## Nomenclature

*Abbreviations*

| | | | |
|---|---|---|---|
| BAU | Business As Usual | LR | Learning Rate |
| BPD | Barrels per day | MC | Medium complexity refinery |
| bbl | Barrels of crude oil | MILP | Mixed Integer Linear Programming |
| Capex | Capital expenditure | Mt | Megatonne (1000,000 t) |
| CC | Carbon capture | NCI | Nelson complexity index |
| CCS | Carbon capture and storage | NET | Negative Emissions Technology |
| CCUS | Carbon capture, utilization and storage | NG | Natural Gas |
| CO2eq | Carbon dioxide equivalent | NPV | Net present value |
| COP | Colombian pesos ($) | NZE | Net Zero Emissions |
| Ecopetrol | Empresa Colombiana de Petroleos | Opex | Operating expenditure |
| EOR | Enhanced oil recovery | O&G | Oil and gas |
| EU | European Union | O&M | Operations and Maintenance |
| FCC | Fluid catalytic cracking | PEM | Proton exchange membrane |
| GDR | Ecopetrol. Refining development management (Gerencia de desarrollo de refinacion) | PV | Photovoltaic |
| GG&BE | Ecopetrol. Gas and low emissions management (Gerencia de gas y bajas emisiones). | REN | Renewable energy |
| GHG | Greenhouse gas | RIS | Refinery information system |
| GWP | Global warming potential | RWGS | Reverse water gas shift |
| HC | High complexity refinery | SCFD | Standard cubic feet of gas per day |
| HDT | Hydrotreating | SMR | Steam methane reformer |
| HCU | Hydrocracking | Syngas | Synthetic gas |
| ICP | Instituto Colombiano del Petroleo | Tonne | 1000kg is a metric tonne (t) |
| LCOE | Levelized cost of electricity | TNO | Netherlands Organization for Applied Scientific Research |
| LCOH | Levelized cost of hydrogen | TRL | Technology readiness level |
| LHV | Low heating value | USD | United States Dollar ($) |

*Symbols*

| | |
|---|---|
| € | Euros ($) |
| MWhe | Electric Mega Watt per hour |
| PJt | Petajoule thermal ($1 \times 10^{15}$ J) |
| Kg | Kilogram |
| MBTUD | Mega BTU per day. $1 \times 10^6$ BTU |
| MSCFD | Million standard cubic feet of gas per day. $1 \times 10^6$ SCFD |

## 1. Introduction

Climate Change impacts involve many risks to human beings and all other forms of life on Earth. These impacts include hotter temperatures, more severe storms, increased drought, warming and rising oceans, loss of species, not enough food, more health risks, poverty, and displacement. (United Nations, 2024).

In the 2015 Paris Agreement, signatory countries recognize that adaptation is a global challenge, and commit to contributing to the long-term global response to climate change. This effort aims to protect people, livelihoods, and ecosystems, with particular consideration given to the urgent and immediate needs of developing countries (United Nations, 2015)

Colombia faces vulnerability in the context of climate change; to illustrate, in 2010, Colombia faced economic losses equivalent to around 2.2 % of the Gross Domestic Product (GDP) attributable to an unusually severe La Niña event. Additionally, in 2015 and 2016, Colombia dealt with an intense drought, an extended El Niño phenomenon, particularly affecting municipalities vulnerable to water shortages; as well the power generation sector has been affected, influencing the power generation of hydroelectric plants, which contribute significantly to the national electricity production, attributed to the low water levels in the reservoirs (Ministerio de Ambiente y Desarrollo Sostenible, 2016). Furthermore, public health issues have arisen due to an increase in vector-borne diseases such as dengue and Zika. In late 2015, Colombia pledged to the international community to implement specific adaptation measures, including ensuring that 100 % of the national territory is equipped with climate change adaptation plans.

Colombia makes up 0.5 % of worldwide emissions; although this percentage is modest, forecasts suggest a potential 50 % increase in emissions by 2030 if preventative measures are not implemented (Ministerio de Ambiente y Desarrollo Sostenible, 2016). Consequently, Colombia has committed to reducing its GHG emissions by 20–30 % by 2030 and achieving net-zero emissions by 2050 (Ministerio de Ambiente y Desarrollo Sostenible, 2016). In 2018, Ecopetrol, a state-owned oil and gas company, was responsible for approximately 4 % of the total GHG emissions in Colombia (11,5 Mt $CO_2$ eq) (IDEAM et al., 2022) and. It committed to reducing its scopes 1 and 2 GHG emissions to 75 % of the level emitted in 2019 by 2030. In addition, the long-term strategy of Ecopetrol aims at achieving net-zero carbon emissions for scopes 1 and 2 by 2050, with a 50 % reduction in total emissions (scopes 1, 2, and 3) in the same year. (Ecopetrol, 2022). There are two Ecopetrol Colombian oil refineries, one located in the middle of the country (Barrancabermeja), with a medium level of process complexity, and the second in the Caribbean coast area (Cartagena), with a high level of process complexity. In the year 2019, the oil refineries were responsible for 55 % of the company's GHG emissions under scopes 1 and 2, with the refineries contributing 98 % of those emissions (Canova, 2021). *Fig. 1* shows a breakdown of the sources of $CO_2$ eq emissions for oil refineries. (Ecopetrol, 2021). Noticeably, the Hydrogen production process exhibits the biggest contrast in the $CO_2$ emissions.

The complexity of a refinery serves as a measure of its sophistication and capital intensity, with broad applications in facility classification, cost estimation, sales price models, and various other applications; for example, correlations that could be used in other fields of knowledge such as options for decarbonization. The best-known list of complexity factors was defined by Nelson in 1960 and published in the Oil & Gas Journal (OGJ), with some later updates in 1998 (Kaiser, 2017). The Nelson Complexity Index for refinery operations is defined as a quantitative measure of how much high-value conversion capacity a refinery has installed relative to its distillation capacity, in other words, it quantifies the type of process units in a refinery and their capacity relative to atmospheric distillation unit, by assigning a factor (Kaiser, 2017). The level of complexity in refineries is not directly correlated with energy efficiency. Solomon[1] introduced the Energy Intensity Index® (EII), which assesses the actual energy consumption of a refinery in comparison to the "standard" energy consumption for a refinery of similar size and configuration. Consequently, a refinery with low complexity may be more energy-efficient than a high complexity one, and vice versa, because the comparison is made with peers having the same configuration (Law Insider, 2023). However, it is well recognized from Solomon's studies (Lei et al., 2021) that high complexity refineries typically display a higher $CO_2$ emission intensity index (t $CO_2$/t crude oil distillation). In the Colombian case, the high complexity Colombian refinery produces 0.33 t $CO_2$/t crude oil distillation, while the medium complexity configuration produces 0.30 t $CO_2$/t crude oil distillation

[1] Solomon Associates (Solomon) is a consulting and benchmarking services company across the energy industry.

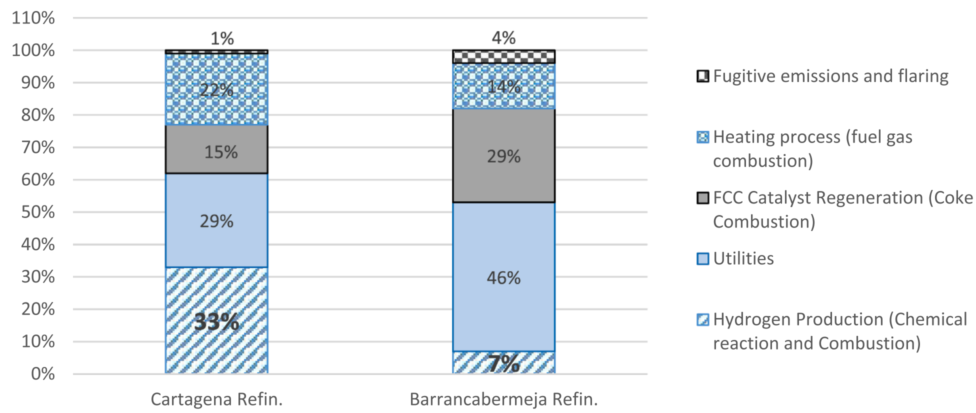


**Fig. 1.** Refinery $CO_2$ eq emissions allocation by origin. Source: (Ecopetrol, 2021).

(RIS Ecopetrol, 2021).

Studies have underscored the differences in various indicators among refineries of different complexity levels. For instance, a TNO study revealed that Dutch refineries in the Port of Rotterdam, categorized as high complexity, exhibit a hydrogen consumption ratio ranging from 8 to 10.9 kt $H_2$/ Mt crude oil, compared to 2.6 to 4.1 kt $H_2$/ Mt crude oil for medium complexity refineries (Oliveira and Schure, 2020). In the Colombian context, the high complexity refinery utilizes 10 kt $H_2$/ Mt crude oil, while the medium complexity configuration consumes 2.9 kt $H_2$/ Mt crude oil (RIS Ecopetrol, 2021). Additional research, including Castelo Branco et al. (2010), demonstrated that higher complexity levels lead to an 89 % increase in hydrogen demand and subsequently higher $CO_2$ emissions due to hydrogen production from natural gas SMR process. Brau et al. (2014) explored the potential of biomass-based hydrogen production as a substitute for SMR units, suggesting it is an effective strategy for reducing $CO_2$ emissions and integral to broader decarbonization efforts.

These results support the need for holistic assessments of possible hydrogen pathways for the refinery sector. However, there is a lack of understanding of 1) the potential impacts on the refinery performance (e.g., product yields and efficiency), under different scenarios (e.g., feedstock, utilities, and product prices) when considering the introduction of different low carbon hydrogen technologies, and 2) the role of the complexity level of an oil refinery in decarbonization strategies, leading to uncertainties regarding technology priorities and scale. To address these knowledge gaps, this paper answers the following research question: *What are the potential impacts of introducing low-carbon intensity hydrogen production in oil refineries with varying levels of refinery complexity, in both the short and long term?*

The novelty of this work lies in three key aspects:

Comprehensive System Analysis of Refinery Complexity: The study uniquely assesses the impact of different complexity levels of oil refineries on decarbonization outcomes, by comparing medium and high complexity refineries in Colombia, is one of the first works using real-site data. The research highlights how the level of complexity influences the effectiveness and economic viability of decarbonization strategies.

Integration of Low-Carbon Hydrogen Technologies: The study provides a novel technical and economic optimization model for integrating low-carbon hydrogen technologies into refinery operations. It offers a detailed analysis of how hydrogen, traditionally used for desulfurization, can be repurposed as a low-carbon fuel source, leading to significant $CO_2$ reductions.

Long-Term and Short-Term Strategies: The research differentiates between short-term and long-term decarbonization strategies, identifying the most cost-effective methods for hydrogen production and the pivotal role of $CO_2$ and renewable electricity prices. The study emphasizes the importance of the short-term horizon for the economic viability of decarbonization efforts, particularly under high-ambition scenarios.

## 2. Case study

This study focuses on a case study based on two Colombian oil refineries. The main characteristics of the refineries are shown in Table 1.

An opportunity for decarbonizing the refineries is the use of hydrogen with a lower carbon footprint both as a feedstock and as a fuel. Currently, the use of hydrogen differs between the refineries. It is noticeable that in the high complexity refinery, hydrogen production contributes 33 % of the emissions, whereas, in the medium complexity refinery, hydrogen corresponds to 7 % of the total $CO_2$ emissions; therefore, the impacts of introducing low-carbon hydrogen are most likely to differ between refinery level of complexity.

## 3. Method

This study comprised five stages (see Fig. 2). First, the demand for

**Table 1**
Main characteristics of the refineries case study. Source: Ecopetrol 2022.

| Parameter | Unit | Cartagena Value | Barrancabermeja Value |
|---|---|---|---|
| Crude oil processing capacity | Mt/year | 11.5 (230 kBPD)[1] | 12 (240 kBPD) |
| Complexity level (NCI) | | 10.1 | 6.1 |
| Conversion rate § | % | 96.7 | 76.7 |
| Gas fuel consumption | PJ/year | 22.6 | 40.3 |
| Electricity production | PJe/year | 3.2 | 2.9 |
| Steam production | PJth/year | 3.5 | 29.7* |
| Hydrogen production | kt/year | 115 | 35.2 |
| Hydrotreatment and hydrocracking process capacity. | Mt/year | 5.6 | 5.5 |
| $H_2$ consumption ratio | kt $H_2$ / Mt Hydrotreatment and Hydrocracking process feedstock. | 15 | 5.1 |
| | kt $H_2$ / Mt crude oil | 10 | 2.9 |
| $CO_2$ emission by $H_2$ production process | kt $CO_2$ eq/year | 830 | 230 |
| Total annual $CO_2$ emissions | kt $CO_2$ eq/year | 2500 | 3100 |

§ The term "conversion rate" typically refers to the efficiency with which crude oil is transformed into higher-value products through various refining processes. The conversion rate is a key performance indicator that reflects the refinery's ability to upgrade lower-value crude oil into more valuable products such as gasoline, diesel, jet fuel, and other refined products. (Kaiser, 2017). * 13 PJt/y to refining process, 10.1 PJt/y to power gen and 6.6 PJt/y supporting activities.

[1] 7.7 Mt/year (155 kBPD) until 3Q-2022.

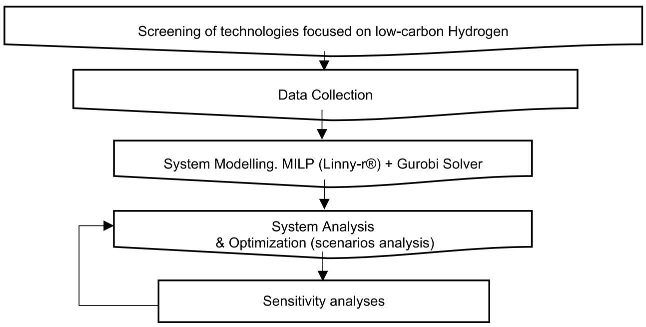


**Fig. 2.** Diagram of method. Visualization of information flow.

low-carbon hydrogen was assessed, and technologies were selected. The data was collected, followed by modelling, system analysis and optimization, and finally, a sensitivity analysis.

### *3.1. Technologies selection*

Since Colombia does not have a low-carbon hydrogen definition, this study adopts the emissions threshold of the EU Hydrogen Strategy, 2.26 $tCO_2$ eq/t $H_2$. (i.e., 25 % SMR carbon footprint), which can be achieved by renewable electricity with water-electrolysis, via biomass gasification, or via coupling CCS to fossil fuel reforming or gasification.

The potential technologies were classified into two time periods of implementation, short-term (by 2030) and long-term (by 2050). The short-term period includes technologies with a technology readiness level (TRL) higher than 8; the long-term period includes technologies currently at a TRL of 3 or higher. This evaluation considered technological, environmental, economic, and deployment criteria, which were defined through a literature review. A survey was then undertaken to gain insights into the relative significance of these criteria for selecting hydrogen production technologies, by consulting experts and stakeholders in the field, including one from academia, one from a Dutch research institute (TNO), two from Colombian research institutes (Instituto Colombiano del Petroleo), and three professionals from the oil refining industry. The surveys are available in the supplementary data repository. The result of the screening process is shown in Table 2. It contains 9 technology options to produce hydrogen, 4 of which can be deployed in the short term and 5 in the long term.

Out of the initial pool of 9 technologies, 4 were finally chosen for this study, including the utilization of non-fossil fuel feedstock (hydrocarbon), innovative commercial approaches, and the integration of existing SMR with CC as a retrofit scenario. The results are presented in Table 3 and will be included in the process model for the system analysis. A readiness timeline for low-carbon technologies was defined based on the outcomes of stages 1 and 2 of the methodology. This timeline serves as input for the Linny-R tool used for further system analysis and optimization.

Note that the carbon capture option evaluated is post-combustion capture, using an amine-based solvent (MEA and AdipX), with a capture efficiency of 90–95 % and heat regeneration consumption in the range of 1.97 −2.7 GJ/t (Meerman et al., 2012). The concentrated $CO_2$ stream resulting from the $CO_2$ capture process ($CO_2$ >95 % wt wet basis) is delivered with moisture content (water) and at a total pressure between 1 and 2 barg. Further, compression and dehydration processes are out of this scope because the system of evaluation is limited by the refinery boundaries and multiple alternatives of downstream process of $CO_2$ capture need to be evaluated deeper in further papers.

### *3.2. Data collection*

Data for the case studies included confidential information about the on-site refinery processes (e.g., yields, mass and energy balance, operational cost) provided by Ecopetrol. This is supplemented by scientific and industrial publications and expert interviews. The mass, energy, and emissions balances were estimated for the annual operation of each process unit under typical conditions. The raw data (e.g., fuel consumption per hour per equipment) used in this study are confidential; therefore, values were aggregated at the block process level (e.g., fuel consumption per year in a process).

### *3.3. System modeling*

A system model was developed to represent the interactions among the technologies being assessed and the pre-existing oil refinery infrastructure. This model spans the timeframe from 2020 to 2050, using a 5-year time step. The model is guided by an optimization objective function aimed at maximizing the total cash flow during each iteration.

Two case studies were modeled using Linny-r® mixed-integer linear programming (MILP software), where the refinery system can be represented by a block diagram. Each block corresponds to a process and the connections represent an energy or mass stream with an associated cost contribution. Linny-r was developed at the Delft University of Technology by Pieter Bots and last updated in July 2023 (v1.9.3) (Bots, 2023).

#### *3.3.1. Process model*

In this section, we briefly present the conceptual model and the Linny-r model. The model contains 75 block processes grouped into 8 process clusters.

The main layer is the site layer whose central components are the utility, oil refining, and low-carbon $H_2$. The utility cluster is based on a natural gas combined cycle cogenerating heat and power. In the oil refining cluster, The high complexity refinery possesses 15 industrial processes, and the medium complexity configuration has 9 industrial processes. Finally, the low-carbon $H_2$ cluster contains the low-carbon hydrogen technologies used in the model.

Fig. 3 shows an overview of the conceptual model.

Fig. 4 shows a representation of the site layer in Linny-r. The layers of the model, symbology, and interpretation, are explained in more detail in Appendix C. All feedstocks/products are connected to a process through a linear function. The water electrolyzers were modeled in units of 25, 35, and 100 t $H_2$/d, biomass-based electricity in units of 60 MW, and biomass-based $H_2$ via gasification in modules of 60 t $H_2$/d. Additionally, the balances in the model are calculated on a daily basis (i.e., tons per day, GJ per day, barrels per day)

### *3.4. System analysis and optimization*

The capacity of utilities and refining processes represent the actual capacity of both oil refineries. Fuel production capacity (e.g. gasoline, diesel, and jet fuel) is defined according to the Ecopetrol long-term production scheduling strategy. Colombian electricity grid connection to the refineries is 70 MW capacity (Available from 2025), 85 €/ MWh (XM, 2020), and a carbon footprint of 186 kg $CO_2$ / MWhe (73 % hydro, 14 % natural gas, and 13 % coal, according to (UPME) (2019). Finally, technologies that involve biomass as feedstock consider only tree species available in Colombia, with Eucalyptus camaldulensis pellets chosen because this species had the highest yield in the areas adjacent to the refinery locations. (Díaz F and Molano M., 2001). Note that no limit was placed on the availability of biomass, water, $CO_2$ transport/storage capacity, and external renewable electricity generation/transportation capacity.

The refineries' system models were verified through the replication of the 2019 material and energy balance, with the model results varying less than 5 % from real-world data. The online repository contains both of the Linny-r models. The models are composed of 190 variables for the high complexity refinery, 178 for the medium complexity refinery model, and 166 and 151 process boundaries (limits of capacity) for the

**Table 2**
Screened low-carbon hydrogen technologies.

| Name | Technology | Production sub-method | Feedstock | Horizon |
|---|---|---|---|---|
| SMR+CC | Thermochemical | Steam Reforming | Hydrocarbon-Natural Gas | Short term |
| Naphtha Reforming + CC | Thermochemical | Steam Reforming | Hydrocarbon-Low grade Naphtha | Short term |
| Ren Elec+Electrolyzer | Electrolysis | PEM electrolysis | Water + Ren. electricity | Short term |
| Biomass Elec+ CC + Electrolyzer | Electrolysis | PEM electrolysis | Water + Biomass EP | Short term |
| Biomass gasification+CC | Thermochemical | Gasification | Biomass EP | Long term |
| Petcoque gasification+CC | Thermochemical | Gasification | Hydrocarbon-Petcoque | Long term |
| Heavy residue fuel+CC | Thermochemical | Gasification | Hydrocarbon-Heavy residue fuel | Long term |
| Methane pyrolysis+CC | Thermochemical | Pyrolysis | Hydrocarbon-Natural Gas/ Biomethane | Long term |
| Autothermal Reforming+CC | Thermochemical | Autothermal Reforming | Hydrocarbon | Long term |

EP: Eucalyptus camaldulensis pellets were chosen because this species yields more in the areas adjacent to the refinery location. Based on Díaz F & Molano M. (2001).

**Table 3**
Selected low-carbon hydrogen technologies for system analysis.

| Name | Feedstock | Horizon | Operational Year |
|---|---|---|---|
| SMR+CCS | Hydrocarbon-Natural Gas | Short term | 2025–2027 |
| Renewable Electricity (Photovoltaic + wind)+ Electrolyzer | Water, Renew. Electricity | Short term | 2025–2030 |
| Electricity from biomass+CCS + Electrolyzer | Water, Eucalyptus *camaldulensis* pellets | Short term | 2025–2030 |
| Biomass gasification+CCS | Eucalyptus *camaldulensis* pellets | Long term | 2035–2040 |

SMR: Steam Methane Reforming, CCS: $CO_2$ capture and storage.

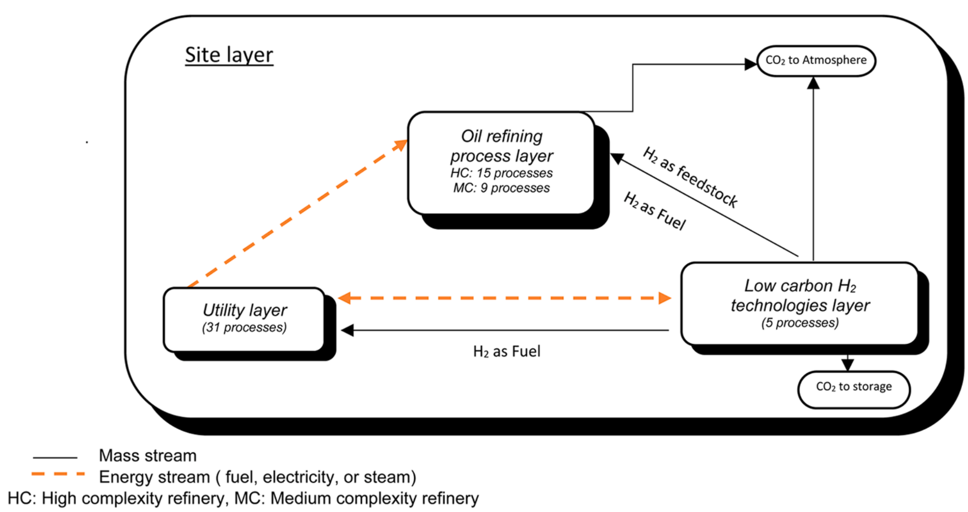


**Fig. 3.** Overview of the conceptual model.

high and medium complexity refinery, respectively

*3.4.1. Optimization*

The model performs single objective optimization aiming to achieve the largest total cash flow through the minimization of the lowest total cost. To minimize the total cost, the model employs as follows:

$$\text{Objective function} = \min OC = \sum_{p=1}^{n} [C_o - C_i]p, \tag{1}$$

where OC is overall cost [€], Co is cost output [€], Ci is cost input [€], and p is process.

Cost input considers the cost of raw material, feedstocks, utilities, and capex/ opex of new technologies; and the cost output category is classified as the income associated with selling products and payment of taxes/penalties.

The fixed operational costs (fixed opex) are defined as a percentage of annual investment cost, while the variable part is calculated in Linny-r based on the consumption of utilities, energy, and materials. Equipment capital costs were obtained from literature and adapted to the capacity of the case study using the exponent method as follow:

$$\frac{Cost\ A}{Cost\ B} = \left(\frac{Scale\ A}{Scale\ B}\right)^{0.67}, \tag{2}$$

where 0.67 is the average scaling factor based on Berghout et al. (2019)

Annualized capex was calculated as

$$\textbf{Annualized investment cost} = \frac{(Capex * r)}{\left(1-(1+r)^{-Lt}\right)}, \tag{3}$$

where r is the discount rate [ %] (12 % for Ecopetrol projects (Yáñez et al., 2018))[2]; Lt is Lifetime [years]. See values for different technologies in Appendix B.

Cost for equipment were updated to 2022 euros using the Chemical Engineering Plant Cost Index, and a currency conversion rate for the year 2022. Prices associated with feedstocks, products, and production capacities are set according to the context of the Colombian economic

[2] Ecopetrol S.A. is a mixed capital company with national state interest and participates in the stock market. From a social perspective assessment normally lower values from 6 % to 8 % are used Laitner et al., (2003) or even lower Kesicki and Strachan, (2011). On the other hand, Industrial and commercial projects could use higher values in a frame from 20 % to 50 %. DeCanio, (1993); Jaffe and Stavins, (1994).

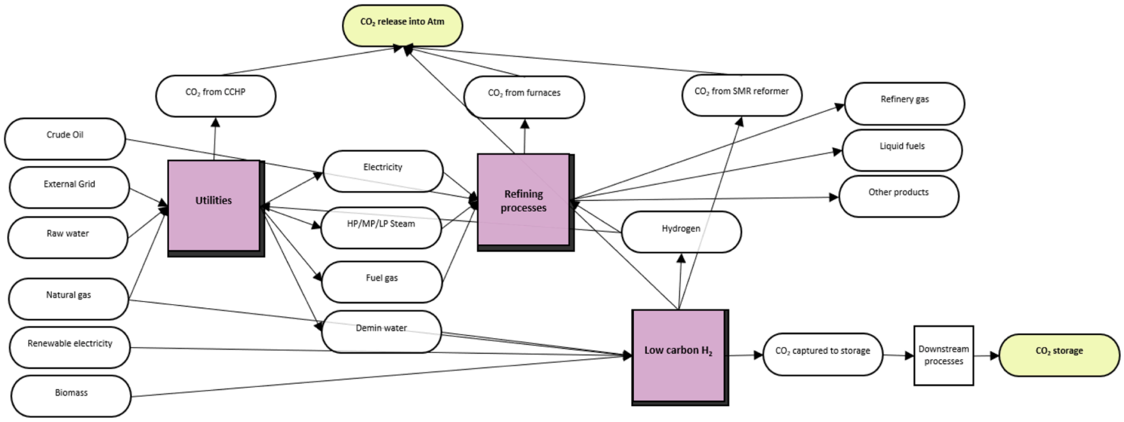


**Fig. 4.** Site layer in Linny-r block diagram (Main layer). Each square could contain multiple clusters and/or process.

scenario.

### 3.4.2. Scenarios

We analyzed the model's results for three different scenarios, Business-As-Usual (BAU), and scenarios of high and low decarbonization. Each scenario varies parameters about techno-economic performance, exogenous parameters such as feedstock and product price market, and decarbonization targets.

*3.4.2.1. Business as usual (BAU).* This scenario represents a "business as usual" world in which no additional efforts are taken to stabilize the atmospheric concentration of greenhouse gases. This scenario uses the refineries' production plan issued in 2022, using the existing facilities and an incremental capacity in the short and long horizon. The baseline point for $CO_2$ emissions was the 2019 $CO_2$ emission levels (scope 1&2). This scenario *neither considers any decarbonization through low-carbon hydrogen production technologies nor any* $CO_2$ *emissions reduction targets.* This scenario is used as a basis for comparison with the low and high scenarios of decarbonization.

Existing facilities include the hydrogen production system via SMR, with PSA (Pressure Swing Adsorption) purification, to obtain 238 t/d (2679,113 $Nm^3$/day) for Cartagena (high complexity) and 95 t/d (1419,930 $Nm^3$/day) for Barrancabermeja (medium complexity) of 99.9 % pure hydrogen. This hydrogen is used in the hydrotreatment process to remove sulfur from the liquid fuels. There are some assumptions in this scenario. First, the processing capacity of the Cartagena refinery will be expanded from 155 kbbl to 235 kbbl in the period between 2020 and 2025 according to existing plans. Additionally, to be able to use the maximum capacity for both oil refineries, there is a plan to expand the $H_2$ production capacity in the medium term. In the short term, there is a project to interconnect the refineries to the Colombian electric grid through a 70 MW line to reduce their carbon footprint. The Colombian electrical grid has a lower carbon footprint compared with the auto-generated electricity generated at the refineries through natural gas power combined cycles because 70 % approximately of Colombian electricity is hydropower. Additionally, as a consequence of the increase in energy efficiency initiatives, there is a goal to achieve the best performance in the peer group (North and South America) in 2035. Thus, the Cartagena refinery will reduce 11 % of energy consumption and Barrancebermeja will reduce 9 % of total energy consumption (Solomon studies, 2018), in the short and medium term horizon. The BAU scenario considers that in 2040, existing SMR units ending their economic lifetime and needing major overhaul investment (normally, every 4 years, units need to replace the catalyst and some preventive and corrective maintenance activities). The major overhaul considers spending 60 % of the original capex; furthermore, the fixed opex cost increases from 3 % to 5 %.

Another important input is the price of natural gas, which varies over time. The forecast series of natural gas prices in the BAU scenario is presented in Table 4.

*3.4.2.2. Decarbonization scenarios.* These scenarios reflect a portfolio of clean energy technologies, with decisions about technology deployment driven by costs, technology maturity, market conditions, available infrastructure, and policy preferences (IEA, 2023). The low ambition decarbonization scenario (LADS) is aligned with the state policies scenario defined in the IEA report 2023. Additionally, this scenario uses a lower learning rate for renewable technologies reflecting slower deployment of capacity over time.

In the high-ambition decarbonization scenario (HADS) scenario the world moves towards decarbonization by significantly reducing fossil fuel use, fewer incentives to explore and produce natural gas, and promoting the adoption of Renewable energy sources (IEA, 2023). It is aligned with the Net Zero Emissions by 2050 Scenario (NZE Scenario) defined in the IEA report 2023. Additionally, this scenario uses a higher learning rate for $H_2$ and electricity from renewable sources. The parameters that defined each decarbonization scenario are summarized in Table 5.

## 3.5. Sensitivity analyses

Finally, we use the net margin[3] (€/bbl) as the metric to evaluate the impacts on the refinery performance, as it is calculated from the total cash flow which is the objective function of the optimization mode. The sensitivity analyses were conducted by modifying $\pm$ 50 % of the value of some key parameters defined for the high ambition decarbonization scenario. Using the variables that defined the scenarios of decarbonization, we chose the $CO_2$ price market, renewable electricity price,

**Table 4**
Natural gas prices forecast. Source: Ecopetrol (2021).

| *Natural gas price Horizon* | *High complexity refinery €/GJ* | *Medium complexity refinery €/GJ* |
|---|---|---|
| *2020* | 4.52 | 5.02 |
| *2025* | 5.43 | 6.63 |
| *2030* | 6.63 | 7.34 |
| *2035* | 6.93 | 8.24 |
| *2040* | 7.13 | 9.14 |
| *2045* | 7.34 | 9,55 |
| *2050* | 7.54 | 10.05 |

[3] Total net cash flow divided by oil processing throughput.

**Table 5**
Parameters considered in the decarbonization scenarios.

| Variables | BAU Value | Low ambition Value | High ambition Value | Source |
|---|---|---|---|---|
| $H_2$ Demand. | $H_2$ as feedstock | $H_2$ as feedstock & $H_2$ as fuel | $H_2$ as feedstock & $H_2$ as fuel | |
| Policy. $CO_2$ emissions target (Scope 1&2). | BL (2019) | 90 % BL (2030) / 50 % BL (2050) | 75 % BL (2030) / Carbon Neutral (2050) | Based on Ecopetrol Goals. |
| $CO_2$ price market. €/t | 0 | 13–21–29 / (2030–2040–2050) | 90–160–200 / (2030–2040–2050) | IEA Report (IEA, 2023). |
| Natural gas price. €/GJ | Data series (see table 3) | BAU+50 % | BAU +100 % | Based on UPME report 2017 (Unidad de Planeación Minero Energética (UPME)., 2020). |
| SMR CAPEX | | 2 % LR[a] | 2 % LR | Based on Ioannis Tsiropoulos et al. (2018) |
| Renewable electricity price (generation). €/MW | 50 (onshore wind) 68 (PV w/o tracker) | PV LR (10 %) Wind LR (2 %) | PV LR (23 %) Wind LR (10 %) | Based on Ioannis Tsiropoulos et al. (2018) |
| Electrolyzer efficiency. | Tech. not used | 5 % improvement / every 5 years | 15 % improvement / every 5 years | (Boston Consulting Group, 2021).1.5- |
| Electrolyzer CAPEX., €/kW | Tech. not used | 1420–543–420 (2022–2030–2050) | 1420–297–217 (2022–2030–2050) | IEA Report (IEA, 2023) |
| Biomass price [b]. €/GJ | 63.7 | Low yield +5 % (2030) +15 % (2050) | High yield +2 % (2030) +9 % (2050) | Based on Boston Consulting Group (2021) and (Sterling and Dtu, 2013) |
| Biomass power and heat. Subcritical Steam Turbine CAPEX | Tech. not used | 2 % LR | 7 % LR | (Ioannis Tsiropoulos et al., 2018) |
| Gasification CAPEX (gasifier) | Tech. not used | 2.5 % LR | 7.6 % LR | (Ioannis Tsiropoulos et al., 2018) |
| $CO_2$ capture CAPEX | Tech. not used | 5 % LR | 30 % LR | (Ioannis Tsiropoulos et al., 2018) |
| $CO_2$ dry, comp, transport & inj. CAPEX | Tech. not used | 3 % LR | 3 % LR | (Ioannis Tsiropoulos et al., 2018) |

BL: Baseline. LR: Learning Rate. PV: Photovoltaic. €: 2022 euros.
[a] It is a mature technology with a slight margin for improvement. [b] Dry and at the refinery gate.

electrolyzers capex, biomass price, biomass gasification capex, and natural gas price as variables for the sensitivity analysis based on their relevance based on the literature and the uncertainty of changing over time.

## 4. Results and discussion

### 4.1. Scenarios results

We split the results obtained from the scenarios into several tables by metrics to facilitate the comparison and the understanding of the reader.

**Table 6**
Low-carbon hydrogen technologies participation and hydrogen balance across BAU, Low, and High decarbonization scenarios.

| High Complexity | 2020 | 2030 | 2050 | Medium Complexity | 2020 | 2030 | 2050 |
|---|---|---|---|---|---|---|---|
| **Scenario: BAU** | | | | | | | |
| $H_2$ production processes | | | | $H_2$ production processes | | | |
| Electrolysis, t/d | 0 | 0 | 0 | Electrolysis, t/d | 0 | 0 | 0 |
| Biomass gasification, t/d | 0 | 0 | 0 | Biomass gasification, t/d | 0 | 0 | 0 |
| | | | | As a byproduct of paraffin production, t/d | 17 | 17 | 17 |
| SMR, t/d | 211 | 285 | 285 | SMR, t/d | 79 | 85 | 85 |
| Nat. gas feedstock for SMR, TJd | 28 | 38 | 38 | Nat. gas feedstock for SMR, TJd | | | |
| **Total Hydrogen demand, t/d** | 211 | 285 | 285 | **Total Hydrogen demand, t/d** | 96 | 102 | 102 |
| As feedstock, t/d | 211 | 285 | 285 | As feedstock, t/d | 96 | 102 | 102 |
| As fuel, t/d | 0 | 0 | 0 | As fuel, t/d | 0 | 0 | 0 |
| **Scenario: High decarbonization** | | | | | | | |
| $H_2$ production processes | | | | $H_2$ production processes | | | |
| Electrolysis, t/d | 0 | 166 | 237 | Electrolysis, t/d | 0 | 78 | 282 |
| Biomass gasification, t/d | 0 | 0 | 180 | Biomass gasification, t/d | 0 | 0 | 0 |
| | | | | As a byproduct of paraffin production, t/d | 17 | 17 | 17 |
| SMR, t/d | 211 | 119 | 0 | SMR, t/d | 79 | 7 | 0 |
| Nat. gas feedstock for SMR, TJd | 28 | 16 | 0 | Nat. gas feedstock for SMR, TJd | 11 | 1 | 0 |
| **Total Hydrogen demand, t/d** | 211 | 285 | 416 | **Total Hydrogen demand, t/d** | 96 | 102 | 300 |
| As feedstock, t/d | 211 | 285 | 285 | As feedstock, t/d | 96 | 102 | 102 |
| As fuel, t/d | 0 | 0 | 131 | As fuel, t/d | 0 | 0 | 198 |
| **Scenario: Low decarbonization** | | | | | | | |
| $H_2$ production processes | | | | $H_2$ production processes | | | |
| Electrolysis, t/d | 0 | 47 | 0 | Electrolysis, t/d | 0 | 6 | 25 |
| Biomass gasification, t/d | 0 | 0 | 180 | Biomass gasification, t/d | 0 | 0 | 120 |
| | | | | As a byproduct of paraffin production, t/d | 17 | 17 | 17 |
| SMR, t/d | 211 | 238 | 105 | SMR, t/d | 79 | 79 | 0 |
| Nat. gas feedstock for SMR, TJd | 28 | 32 | 14 | Nat. gas feedstock for SMR, TJd | 11 | 11 | 0 |
| **Total Hydrogen demand, t/d** | 211 | 285 | 285 | **Total Hydrogen demand, t/d** | 96 | 102 | 162 |
| As feedstock, t/d | 211 | 285 | 285 | As feedstock, t/d | 96 | 102 | 102 |
| As fuel, t/d | 0 | 0 | 0 | As fuel, t/d | 0 | 0 | 60 |

#### *4.1.1. Low-carbon hydrogen production technologies*

As seen in Table 6, the decarbonization scenarios show a significant shift towards alternative hydrogen production technologies (i.e., not based on natural gas or other fossil hydrocarbons as raw material), achieving a total replacement for both refineries by 2050 in the HADS. In the short term, the penetration of the alternative technologies of hydrogen is 58 % and 76 % for the high and medium complexity refineries, respectively. On the other hand, in the LADS, hydrogen production migrates slower to the alternative technologies, being 16 % and 6 % in the short term for the high and medium complexity refineries, respectively; however, in the long term, the high and medium complexity refineries respectively replace 63 % and 90 % of fossil $H_2$ production. Hydrogen production via biomass gasification emerges in both decarbonization scenarios as a significant option in the long term, contributing to up to 74 % of total hydrogen production in the MC refinery. Nevertheless, in real life, this production has to be supported by a well-structured supply chain of biomass to the gate of refineries. Additionally, switching gas fuel toward hydrogen in boilers and furnaces is required in the HADS long-term to achieve in both refineries the decarbonization goals.

The combination of chosen technologies in this study presents an opportunity to employ low-carbon intensity hydrogen as a viable decarbonization solution, demonstrating feasibility in a technological and economic assessment. In the short term, water PEM electrolysis presents an opportunity, due to its TRL, modular assembly, flexibility, and applicability in the industrial sector, as long as it can be enhanced to a significant industrial scale (i.e., 50–100 $tH_2$/d or 250–500 MW electrolyzer), powered by low-cost renewable electricity, and supported by a robust electrical infrastructure for sourcing, transmission, and distribution. thereby positioning it on par with technologies such as SMR + CCS in a scenario of high natural gas prices. See results in Table 7.

The results presented in Table 7 corroborate the findings reported by Glenk and Reichelstein (2019). They indicated values of 1.5–2.5 €/ kg for large-scale fossil fuel hydrogen supply (without CCS) in Germany and 1.8–2.9 €/ kg in Texas. Additionally, their projections for renewable hydrogen production by 2030 (via water electrolysis) were 2.0–2.4 €/ kg for Germany and 2.2–2.7 €/ kg for Texas.

#### *4.1.2. Impacts on utility balance*

As Table 8 shows, in the Business-As-Usual (BAU) scenario, the steam demand decreases to the range of 60–80 % in both refineries, as a consequence of substituting the electricity generated from a high pressure steam turbine with electricity obtained from the Colombian grid. Other utilities remain relatively constant, showing a slight downward trend primarily attributed to the implementation of energy efficiency initiatives described in Section 3.4.2.1. Nevertheless, the 26 % increase in the processing capacity at the Cartagena refinery in the short term, led to a corresponding 13 % rise in electricity demand.

**Table 7**
Comparison of hydrogen production costs evolution for high complexity refinery. High-ambition scenario.

| Year | Nat Gas price, €/ GJ | SMR +CCS, €/ kg $H_2$ | REN electricity price, €/MWh | PEM electrolyzer, €/ kg $H_2$ |
|---|---|---|---|---|
| **2030** | | | | |
| Input low prices | 6.6 | 2.1 | 32 | 1.8 |
| Input high prices | 13.2 | 3.0 | 43 | 2.3 |
| **2050** | | | | |
| Input low prices | 7.5 | 2.3 | 22 | 1.0 |
| Input high prices | 15.0 | 3.3 | 49 | 1.9 |

In the HADS, the external sourcing of natural gas for furnaces and boilers is eliminated and completely substituted with low-carbon hydrogen by 2050. However, refinery gas, a byproduct of the refining process, cannot be replaced without causing an overabundance, leading to the necessity of burning the excess in the flare. This process would fail to reduce $CO_2$ emissions.

The demand for electrical energy increases significantly in the short and long term, particularly electricity generated from renewable sources to power electrolyzers. In contrast, electricity generation from natural gas is minimized but is still used to provide reliability and support for the intermittent supply of photovoltaic and wind-generated electricity. In HADS, the demand for renewables in the high complexity refinery is 2.1 times higher than that in the medium complexity refinery in the short term, however, in the long term, the demand for renewable electricity is similar to the high complexity refinery demand, only 10 % higher than the medium complexity refinery. The short-term increase in renewable electricity demand, totaling 367 MW for HC and 171 MW for MC refineries, raises concerns about the adequacy of the electrical system's supply capacity (generation and transmission) by 2030. This supply becomes a limiting factor when compared to the most recent plan for the expansion of Colombia's electrical system, as outlined by UPME for the 2022–2036 period because It is not aligned with the demand projected in this study, creating a short-term bottleneck (Torres et al., 2021). On the other hand, in the long term, the medium complexity refinery demand of electricity generation from biomass with CCS is 5.7 times larger than the high complexity refinery. This increase is due to the need to compensate for the emissions produced by refinery gas still used as fuel in boilers and furnaces, which in the medium complexity refinery is 2.25 times higher than in the high complexity refinery.

In the high decarbonization scenario, the demand of high-pressure (HP) steam declines in the short term due to less demand for electricity generation in the power system; however, in the long term, the demand of HP steam rises for both electricity generation and the production of low-pressure steam (LP) used in the $CO_2$ capture process. The additional LP steam demand for high and medium complexity refineries is 4.8 and 4.4 kt/d, respectively; resulting in LP steam demand reaching up to 50 % of HP steam demand in the long term.

The highest water demand occurs in the HADS, due to hydrogen production via water electrolysis, with long-term demand increasing by 50 % and 38 % for the high and medium complexity refineries, respectively. This heightened demand may affect the reliability of the water supply, leading refineries to look for alternative sources, such as water table (e.g. groundwater wells) or desalinated seawater. These alternatives would need additional treatment to meet the quality standards set by electrolyzer manufacturers, consequently increasing electricity consumption and production costs associated with the additional treatment.

Biomass demand might potentially be met based on Colombia's large estimate in this area. For example, the region near both refineries could offer 100–200 PJ/year of biomass (Younis et al., 2021); however, a proposal received by Ecopetrol indicates a lower feasible amount of 620 t/d (11 TJd or 4 PJ/year) dry biomass at the refinery gate.

#### *4.1.3. Oil processing throughput and total CO2 emissions*

It is notable (in Table 9) that both refineries can achieve all emission reduction targets in the short and long term in both scenarios of decarbonization, as long as the supply chain provides enough renewable electricity and biomass.

The high decarbonization scenario highlights the opportunity for a significant reduction in $CO_2$ emissions in both refineries when compared to the low decarbonization scenario. For the LADS, the high complexity refinery reduces its $CO_2$ emissions by 18 % in the short term and 46 % in the long term. Similarly, albeit to a lesser extent, in the medium complexity refinery, emissions are reduced by 16 % in the short term and 50 % in the long term.

Finally, biogenic $CO_2$ capture and storage plays a significant role in

**Table 8**
Impacts on Utility Balance across BAU, Low, and High Decarbonization Scenarios.

| High Complexity | 2020 | 2030 | 2050 | Medium Complexity | 2020 | 2030 | 2050 |
|---|---|---|---|---|---|---|---|
| **Scenario: BAU** | | | | | | | |
| Natural gas (external source), TJd | 16 | 15 | 14 | Natural gas (external source), TJd | 19 | 18 | 19 |
| Refinery gas (internal source), TJd | 26 | 28 | 28 | Refinery gas (internal source), TJd | 63 | 63 | 63 |
| **Total fuel gas demand, TJd** | **42** | **43** | **42** | **Total fuel gas demand, TJd** | **82** | **81** | **82** |
| Natural Gas combustion turbine, MWh | 44 | 26 | 25 | Natural Gas combustion turbine, MWh | 42 | 25 | 25 |
| HP Steam turbine, MWh | 53 | 15 | 17 | HP Steam turbine, MWh | 51 | 11 | 11 |
| External grid, MWh | 0 | 70 | 69 | External grid, MWh | 0 | 56 | 56 |
| Renewables, MWh | 0 | 0 | 0 | Renewables, MWh | 0 | 0 | 0 |
| PV and wind electricity, MWh | 0 | 0 | 0 | PV and wind electricity, MWh | 0 | 0 | 0 |
| Biomass electricity, MWh | 0 | 0 | 0 | Biomass electricity, MWh | 0 | 0 | 0 |
| **Total electricity demand, MWh** | **98** | **111** | **111** | **Total electricity demand, MWh** | **93** | **92** | **92** |
| **Total steam demand, kt/d** | **13** | **9** | **9** | **Total steam demand, kt/d** | **12** | **7** | **7** |
| **Raw water demand, kt/d** | **14** | **10** | **10** | **Raw water demand, kt/d** | **14** | **10** | **10** |
| **Scenario: High decarbonization** | | | | | | | |
| Natural gas (external source), TJd | 16 | 12 | 0 | Natural gas (external source), TJd | 19 | 20 | 0 |
| Refinery gas (internal source), TJd | 26 | 28 | 28 | Refinery gas (internal source), TJd | 63 | 63 | 63 |
| **Total fuel gas demand, TJd** | **42** | **40** | **28** | **Total fuel gas demand, TJd** | **82** | **83** | **63** |
| Natural Gas combustion turbine, MWh | 44 | 25 | 25 | Natural Gas combustion turbine, MWh | 42 | 0 | 0 |
| HP Steam turbine, MWh | 53 | 20 | 56 | HP Steam turbine, MWh | 51 | 26 | 35 |
| External grid, MWh | 0 | 65 | 70 | External grid, MWh | 0 | 70 | 70 |
| Renewables, MWh | 0 | 368 | 395 | Renewables, MWh | 0 | 171 | 471 |
| PV and wind electricity, MWh | 0 | 350 | 371 | PV and wind electricity, MWh | 0 | 129 | 338 |
| Biomass electricity, MWh | 0 | 18 | 24 | Biomass electricity, MWh | 0 | 42 | 133 |
| **Total electricity demand, MWh** | **98** | **478** | **546** | **Total electricity demand, MWh** | **93** | **267** | **576** |
| HP steam for power gen, kt/d | 8.1 | 5.1 | 10 | HP steam for power gen, kt/d | 7.6 | 5.3 | 6.5 |
| **Total steam demand, kt/d** | **13** | **10** | **18** | **Total steam demand, kt/d** | **12** | **10** | **16** |
| LP steam demand for CC, kt/d | 0 | 1.0 | 4.8 | LP steam demand for CC, kt/d | 0 | 1.4 | 4.4 |
| **Raw water demand, kt/d** | **14** | **14** | **21** | **Raw water demand, kt/d** | **14** | **13** | **18** |
| **Dry biomass demand, t/d** | **0** | **588** | **2606** | **Dry biomass demand, t/d** | **0** | **1431** | **4462** |
| Dry biomass, TJd | 0 | 11 | 48 | Dry biomass, TJd | 0 | 26 | 83 |
| Land requirement, kha | 0 | 19 | 86 | Land requirement, kha | 0 | 47 | 147 |
| **Scenario: Low decarbonization** | | | | | | | |
| Natural gas (external source), TJd | 16 | 34 | 16 | Natural gas (external source), TJd | 19 | 21 | 17 |
| Refinery gas (internal source), TJd | 26 | 28 | 28 | Refinery gas (internal source), TJd | 63 | 63 | 63 |
| **Total fuel gas demand, TJd** | **42** | **62** | **44** | **Total fuel gas demand, TJd** | **82** | **84** | **80** |
| Natural Gas combustion turbine, MWh | 44 | 56 | 25 | Natural Gas combustion turbine, MWh | 42 | 0 | 0 |
| HP Steam turbine, MWh | 53 | 55 | 55 | HP Steam turbine, MWh | 51 | 24 | 52 |
| External grid, MWh | 0 | 3 | 70 | External grid, MWh | 0 | 70 | 70 |
| Renewables, MWh | 0 | 116 | 0 | Renewables, MWh | 0 | 14 | 50 |
| PV and wind electricity, MWh | 0 | 96 | 0 | PV and wind electricity, MWh | 0 | 0 | 25 |
| Biomass electricity, MWh | 0 | 20 | 0 | Biomass electricity, MWh | 0 | 14 | 25 |
| **Total electricity demand, MWh** | **98** | **230** | **150** | **Total electricity demand, MWh** | **93** | **108** | **172** |
| HP steam for power gen, kt/d | 8.1 | 8.7 | 10 | HP steam for power gen, kt/d | 7.6 | 4.5 | 7.1 |
| **Total steam demand, kt/d** | **13** | **16** | **17** | **Total steam demand, kt/d** | **12** | **9** | **15** |
| LP steam demand for CC, kt/d | 0 | 1.6 | 4.4 | LP steam demand for CC, kt/d | 0 | 0.9 | 3.1 |
| **Raw water demand, kt/d** | **14** | **16** | **17** | **Raw water demand, kt/d** | **14** | **12** | **15** |
| **Dry biomass demand, t/d** | **0** | **672** | **1800** | **Dry biomass demand, t/d** | **0** | **457** | **2053** |
| Dry biomass, TJd | 0 | 12 | 33 | Dry biomass, TJd | 0 | 8 | 38 |
| Land requirement, kha | 0 | 22 | 59 | Land requirement, kha | 0 | 15 | 67 |

the outcomes of decarbonization, injecting underground volume equivalents to 67 % and 95 % of the original 2020 $CO_2$ emissions level of the high and medium complexity refineries, respectively. This process compensates for the remaining $CO_2$ emissions into the atmosphere from the combustion of fossil fuel in boilers, combustion turbines, and furnaces.

#### 4.1.4. *Economic impacts*

Table 10

The high complexity refinery with higher conversion of crude oil into valuable products has a higher refining margin compared to medium complexity (lower conversion) refinery. This aligns with the findings found in the literature review and data from the industry where higher conversion rates normally increase refining margins.

In the BAU scenario, the refining margin reduces through the years. For the high complexity refinery, the refining margin decreases by 27 % in the short term and 33 % in the long term compared with 2020 levels. Meanwhile, for the medium complexity refinery, the negative trend is more profound with a reduction of 37 % in the short term and 41 % in the long term, compared to the 2020 margin. The primary factor contributing to the unfavorable outcome in the refining margin is the more rapid escalation of the market price of natural gas compared to the ascent of refining product prices.

On the other hand, the high decarbonization scenario presents a significant reduction in the refining margin, followed by a gradual recovery in the long term. In 2030, the HC refinery in HADS has a 40 % lower margin than in the BAU scenario, but this gap decreases to 5 % by 2050. Meanwhile, for the medium complexity refinery, the difference in margin with BAU is 50 % lower in the short term, but 22 % higher in the long term.

In the low ambition decarbonization scenario, the refining margin experiences a reduction less severe than in the high ambition decarbonization scenario compared to BAU in the short term. In 2030, the HC refinery in LADS has a 5 % lower margin than in the BAU scenario, increasing this gap to 10 % by 2050. Meanwhile, for the medium complexity refinery, the difference in margin improves by 22 % in both the short and long term.

**Table 9**
Throughput and CO2 emissions across BAU, Low, and High Decarbonization Scenarios.

| High Complexity | 2020 | 2030 | 2050 | Medium Complexity | 2020 | 2030 | 2050 |
|---|---|---|---|---|---|---|---|
| **Scenario: BAU** | | | | | | | |
| Oil refinery throughput, kbld | 155 | 196 | 196 | Oil refinery throughput, kbld | 240 | 242 | 242 |
| Kty | 7718 | 9752 | 9752 | Kty | 11,931 | 12,034 | 12,034 |
| Utilization capacity, % | 100 % | 83 % | 83 % | Utilization capacity, % | 99 % | 99 % | 99 % |
| **Net $CO_2$ emissions[†], kt $CO_2$/y** | **2490** | **2573** | **2551** | **Net $CO_2$ emissions[†], kt $CO_2$/y** | **3496** | **3361** | **3347** |
| **Scenario: High decarbonization** | | | | | | | |
| Oil refinery throughput, kbld | 155 | 196 | 196 | Oil refinery throughput, kbld | 240 | 242 | 242 |
| Kty | 7718 | 9752 | 9752 | Kty | 11,931 | 12,034 | 12,034 |
| Utilization capacity, % | 100 % | 83 % | 83 % | Utilization capacity, % | 99 % | 99 % | 99 % |
| **Net $CO_2$ emissions[†], kt $CO_2$/y** | **2490** | **1616** | **0** | **Net $CO_2$ emissions[†], kt $CO_2$/y** | **3496** | **2332** | **0** |
| $CO_2$ released into the atmosphere, fossil source | 2490 | 1905 | 1289 | $CO_2$ released into the atmosphere, fossil source | 3496 | 3034 | 2205 |
| $CO_2$ released into the atmosphere, biosource | 0 | 42 | 186 | $CO_2$ released into the atmosphere, biosource | 0 | 102 | 318 |
| Removed from the atmosphere, via biomass photosynthesis | 0 | 421 | 1865 | Removed from the atmosphere, via biomass photosynthesis | 0 | 1024 | 3193 |
| Biogenic $CO_2$ to storage | 0 | 377 | 1670 | Biogenic $CO_2$ to storage | 0 | 917 | 2858 |
| Fossil $CO_2$ to storage | 0 | 227 | 0 | Fossil $CO_2$ to storage | 0 | 13 | 0 |
| **Scenario: Low decarbonization** | | | | | | | |
| Oil refinery throughput, kbld | 155 | 196 | 196 | Oil refinery throughput, kbld | 240 | 242 | 242 |
| Kty | 7718 | 9752 | 9752 | Kty | 11,931 | 12,034 | 12,034 |
| Utilization capacity, % | 100 % | 83 % | 83 % | Utilization capacity, % | 99 % | 99 % | 99 % |
| **Net $CO_2$ emissions[†], kt $CO_2$/y** | **2490** | **2070** | **1150** | **Net $CO_2$ emissions[†], kt $CO_2$/y** | **3496** | **2896** | **1753** |
| $CO_2$ released into the atmosphere, fossil source | 2490 | 2399 | 2182 | $CO_2$ released into the atmosphere, fossil source | 3496 | 3156 | 2923 |
| $CO_2$ released into the atmosphere, biosource | 0 | 48 | 128 | $CO_2$ released into the atmosphere, biosource | | 33 | 146 |
| Removed from the atmosphere, via biomass photosynthesis | 0 | 481 | 1288 | Removed from the atmosphere, via biomass photosynthesis | 0 | 327 | 1469 |
| Biogenic $CO_2$ to storage | 0 | 430 | 1155 | Biogenic $CO_2$ to storage | 0 | 293 | 1316 |
| Fossil $CO_2$ to storage | 0 | 454 | 201 | Fossil $CO_2$ to storage | 0 | 151 | 0 |

[†] Scope 1 & 2.

**Table 10**
Economic Impacts across BAU, Low, and High Decarbonization Scenarios.

| High Complexity | 2020 | 2030 | 2050 | Medium Complexity | 2020 | 2030 | 2050 |
|---|---|---|---|---|---|---|---|
| **Scenario: BAU** | | | | | | | |
| Net margin, €/bbl | 6.2 | 4.5 | 4,1 | Net margin, €/bbl | 4.5 | 2.8 | 2.7 |
| Hydrogen production cost, €/ kg $H_2$ | 1.6 | 1.8 | 1.6 | Hydrogen production cost, €/ kg $H_2$ | 1.6 | 1.9 | 1.8 |
| **Scenario: High decarbonization** | | | | | | | |
| Net margin, €/bbl | 6.2 | 2.7 | 3.9 | Net margin, €/bbl | 4.5 | 1.4 | 3.4 |
| Hydrogen production cost, €/ kg $H_2$ | 1.6 | 2.5 | 1.7 | Hydrogen production cost, €/ kg $H_2$ | 1.6 | 2.7 | 1.6 |
| **Scenario: Low decarbonization** | | | | | | | |
| Net margin, €/bbl | 6.2 | 4.2 | 3.7 | Net margin, €/bbl | 4.5 | 3.5 | 3.3 |
| Hydrogen production cost, €/ kg $H_2$ | 1.6 | 2.6 | 2.3 | Hydrogen production cost, €/ kg $H_2$ | 1.6 | 2.4 | 2.3 |

### 4.2. *Sensitivity analysis results*

The following sensitivity analysis explores the influence of 3 key parameters, $CO_2$ price market, biomass supply capacity, and improvement curve of electrolyzer capex.

#### 4.2.1. *$CO_2$ price market*

Given the significant impact of the $CO_2$ price market on refinery profitability in decarbonization scenarios, we conducted a sensitivity analysis to understand at which $CO_2$ price refineries break even in the high decarbonization scenario.

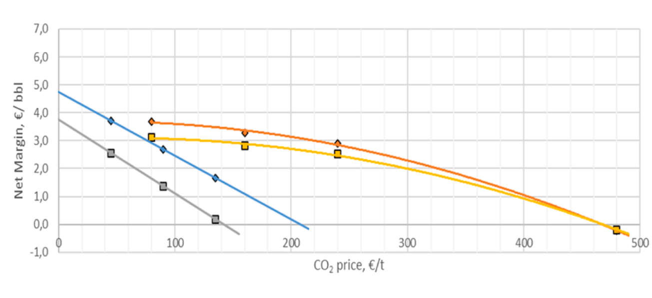


**Fig. 5.** Sensitivity analysis of $CO_2$ price in refinery net margin.

Fig. 5 shows the findings of this sensitivity analysis. The findings suggest that in the short term, the medium complexity (MC) refinery maintains its viability up to a $CO_2$ price of €140/t $CO_2$, while the high complexity (HC) refinery displays greater resilience, enduring $CO_2$ prices of up to €205/t $CO_2$ due to its production of more valuable products. In the long term, the threat diminishes and both refineries remain viable up to a $CO_2$ price of €470/t $CO_2$. This can be explained as a consequence of the adoption of technologies for hydrogen production that have improved capex/opex and efficiency over time. It's worth noting that according to the IEA 2023 report, $CO_2$ prices in net-zero scenarios are projected to reach €90 by 2030 and €200 by 2050.

#### 4.2.2. *Biomass supply*

Biomass has been demonstrated to be a critical factor in achieving the long-term $CO_2$ neutrality goal, also based on the fact that biomass is a limited resource, we decided to run two further runs to get an insight into how the system behaves when the maximum biomass supply is one-third of the total demand required in HADS (e.g. without restriction on capacity). As shown in Fig. 6, the optimized solution suggests that the long-term decarbonization goals cannot be achieved with such a restricted biomass supply; thus, $CO_2$ emissions are reduced to 68 % and 55 % from 2020 levels for the HC and MC refineries, respectively.

In this scenario, the results show that the constraint of biomass-based technologies production leads to a 4 % increase in total hydrogen

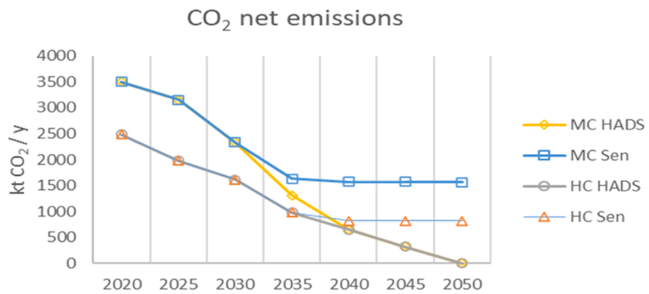


**Fig. 6.** $CO_2$ emissions comparison under one-third of biomass supply constraint.

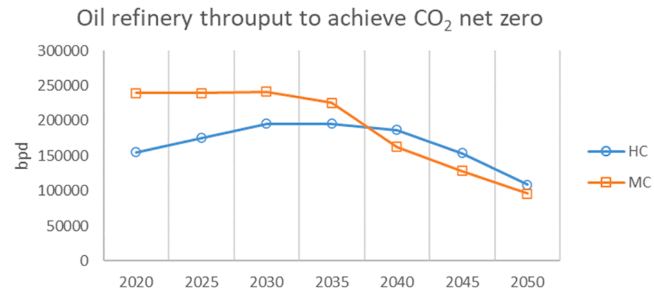


**Fig. 8.** Oil refinery throughput affectation under one-third of biomass supply constraints.

production. The insufficient supply of dry biomass supply is offset by water electrolyzers powered by PV and wind electricity in the long term (Fig. 7). Therefore, hydrogen production from water electrolyzers powered by PV and wind electricity increases by 1.9 times while hydrogen from the biomass gasification process is no longer considered a viable option.

To achieve $CO_2$ neutrality in the long term under this biomass supply constraint, the processing oil capacity for both refineries must be reduced to 56 % and 40 % for the HC and MC refineries, respectively. These results are shown in Fig. 8.

### 4.2.3. Delay of the electrolyzer's capex improvement

Water-electrolyzer technology has been demonstrated to play a significant role in the short-term decarbonization goal. This fact motivates us to conduct a sensitive analysis if electrolyzer costs do not rapidly decrease, considering the electrolyzer's capex improvement doesn't decrease in the first 10 years. The results point out that although this delay does not impact the long-term goal of achieving $CO_2$ neutrality, it does impact the net margin. The most significant impact is an 11 % reduction, observed in the medium complexity refinery in 2035 (See Fig. 9). Fig. 10 illustrates the impact of this delay on the portfolio of deployed $H_2$ technologies. The results show that, in the short term, the use of water electrolysis technology is reduced by 77 % and it is compensated by the increase in production of SMR+CCS in the high complexity refinery. On the other hand, the hydrogen production in the medium complexity refinery is reduced by 54 %, as a consequence of the reduction in 90 % of water electrolysis production.

In the long term, biomass-based $H_2$ mitigates this constraint, leading to a 22 % increase in biomass-based $H_2$ production in the high complexity refinery. In the medium complexity refinery, a 36 % reduction in water electrolysis technology is compensated by increasing the production of biomass-based hydrogen.

## 4.3. Discussion

Given that hydrogen production contributes differently to the overall

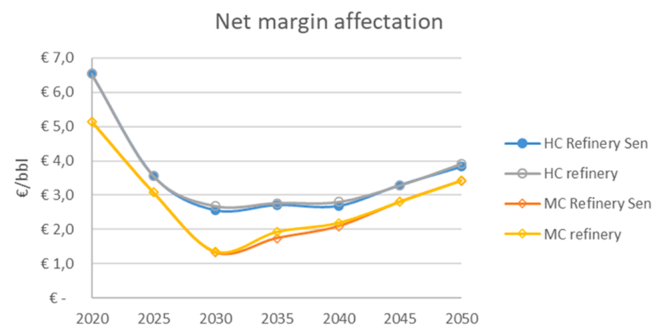


**Fig. 9.** Net margin impact under a constraint of delayed improvement in the electrolyzer capex.

$CO_2$ emissions inventory of both refineries, the deployment of low-carbon intensity hydrogen technologies varies for each refinery. For example, the medium complexity refinery requires greater Negative Emissions Technologies (NETs) to achieve $CO_2$ neutrality, such as biomass-based electricity or biomass-derived hydrogen coupled with $CO_2$ capture and storage (CCS). However, implementing NETs involves higher costs, both in terms of investment and operational expenses, and requires well-organized logistics for activities such as tree planting, collection, and transportation. Fortunately, the region where the Barrancabermeja refinery (MC) is located boasts significant potential for woody biomass, estimated at 100–200 PJ/year of biomass (Younis et al., 2023), which seems to be adequate to support the 30 PJ/year of biomass required in the HADS in the long term, but whether that theoretical potential is realizable remains to be confirmed.

The utility infrastructure faces substantial challenges, requiring enhancement to meet long-term demand, particularly in the HADS. This applies primarily to low pressure steam, renewable electricity generation, and infrastructure associated with electricity transportation from external sources. This expected growth includes an 80 – 137 % increase in steam demand to support the $CO_2$ capture process, and a significant

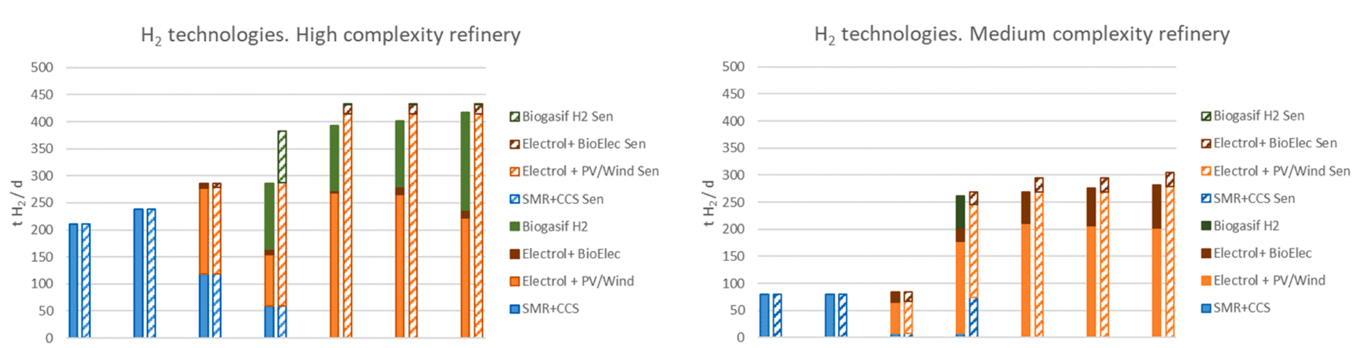


**Fig. 7.** Deployment comparison of hydrogen technologies under one-third of biomass supply constraints.

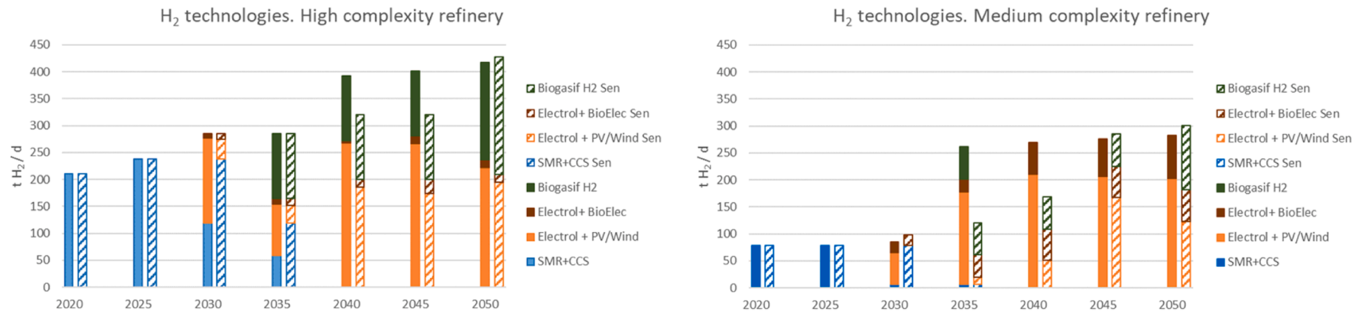


**Fig. 10.** Deployment comparison of hydrogen technologies under a ten-year delay of the Electrolyser's capex improvement curve.

expansion in renewable electricity demand, especially in the short term reaching 1.2 to 4.9 times the original total electricity levels, and up to 6.2 times in the long term.

Since, the level of complexity plays a significant role in the deployment of decarbonization technologies, as discussed earlier, we aim to compare the outcomes of our current study with those of previous ones. We employ the hydrogen ($H_2$) consumption index as a metric to contrast different types of oil refineries, as the term "level of complexity" was not consistently used in previous studies. As an illustrative comparison, consider the REFAP oil refinery located in Brazil, with a daily processing capacity of 32,000 $m^3$/day (equivalent to 201 kBPD or 10 Mt/year) and a hydrogen consumption ratio of 4.1 kt $H_2$/ Mt of crude oil, as reported by Nascimento da Silva et al. in 2022 (Colombian HC refinery has hydrogen consumption ratio of 7.7 kt $H_2$/ Mt of crude oil, and the MC refinery has 2.4 kt $H_2$/ Mt of crude oil). They evaluated the utilization of surplus wind energy to power electrolyzers, achieving a reduction in emissions ranging from 10.4 % to 14 % by using 30 % and 50 % wind energy shares and the Brazilian electricity grid. Our study made significant progress in this application, achieving a 25 % reduction in $CO_2$ emissions across both refineries in the short term, using renewable electricity in 77 % and 58 % of the total electricity demand in the HC and MC refineries, respectively.

Previous research conducted by Brau et al. (2013–2014) explored the utilization of hydrogen in an oil refinery context through the thermal gasification of biomass in a high complexity Swedish refinery, which has a hydrogen consumption ratio of 9.6 kt $H_2$/ Mt crude oil. The authors report a reduction of approximately 92 % in emissions attributable to the existing Steam Methane Reforming (SMR) process, assuming an unrestricted biomass supply. Similarly, our study employs biomass-based technologies to achieve net-zero $CO_2$ emissions (Scope 1&2) in the HADS, entirely replacing the SMR technology and accounting for 59 % and 72 % of the reduction in the high and medium complexity refineries, respectively.

Despite effectively representing two oil refinery configurations using a MILP model, this study found limitations in applying linear programming to inherently nonlinear processes. This issue was addressed by narrowing the operational capacity range under evaluation, which affected the accuracy of mass and energy balances, with deviations less than 5 % when compared to actual refinery data. Another limitation arises from the use of unrestricted availability of resources, so for that reason, a sensitivity analysis of Biomass supply was conducted, based on Biomass has demonstrated being a critical factor in achieving the long-term $CO_2$ neutrality goal. Additionally, this study includes technologies with TRL [8–9] for the short term with technologies with lower TRL for the medium and long term, generating uncertainties about results in the long term. We manage this situation by using the learning rate curves from open-access sources for commercial technologies, and a sensitivity analysis for the key parameters detected in this study to analyze the behavior of the system and changes in the optimized solution.

Another limitation is related to using a single objective function in optimization. In this study, the default objective function in Linny-R was employed to maximize cash flow, while setting constraints for other key parameters, such as capping maximum CO2 emissions per period. A multi-objective optimization approach could provide more realistic solutions by accommodating conflicting objectives, thereby generating a set of trade-offs rather than a single optimal solution. Additionally, the study was limited by data availability concerning refineries with varying levels of complexity. For instance, low-complexity refineries were not included in this study; however, such refineries represent only 5–10 % of the global total, compared to 50 % of medium complexity and 35 % of high complexity refineries (Kaiser, 2017).

## 5. Conclusions

In this study, we conducted a comprehensive system analysis and optimization for two Colombian oil refineries operating at different levels of complexity. Our modeling results for the case study underscore the important impact of the refinery's complexity level on the outcomes of the decarbonization efforts. To provide clarity, we have highlighted the key conclusions as follows:

First, integrating low-carbon hydrogen technologies in refineries is a feasible strategy for achieving CO2 reduction goals in both the short and long term. This study offers a technically and economically optimal solution for utilizing energy sources, process units, and utilities. However, achieving long-term $CO_2$ neutrality will require additional technological advancements and operational strategies, as refineries have historically used hydrogen mainly for desulfurization. In a high-ambition decarbonization scenario, fossil-based hydrogen for desulfurization is replaced by low-carbon hydrogen. Moreover, hydrogen is identified as a feasible alternative to conventional gas fuels in refinery operations, further reducing $CO_2$ emissions.

Second, the deployment of decarbonization technologies prioritizes renewable electricity, including a significant participation of electricity from biomass coupled with $CO_2$ capture and storage to power water electrolyzers. Steam methane reforming + CCS technology is initially the more cost-effective method for low-carbon hydrogen production, phasing out gradually over the long term. Beyond 2030, biomass-based technologies + CCS remain costly, but biomass via negative emissions emerges as a feasible alternative for achieving net-zero $CO_2$ emissions.

Third, in the decarbonization scenario, refinery net margins are significantly influenced by the prices of $CO_2$ and renewable electricity. In the short term, natural gas prices remain critical due to the ongoing use of steam methane reforming. The results indicate that the short-term period is crucial, especially in high-ambition decarbonization scenarios. A medium-complexity refinery is economically viable up to a $CO_2$ price of €140/t, while a high-complexity refinery endures up to €205/t.

Fourth, high complexity refineries are better equipped to manage the economic impacts of decarbonization. In the short term, high decarbonization scenarios could negatively impact refining margins by 42 % to 50 %.

Fifth, integrating low-carbon hydrogen as a fuel source in refineries results in significant long-term $CO_2$ reductions. For example, the high-complexity refinery configuration achieves an additional reduction of 318 kt $CO_2$/y, or 13 % of the original emissions, while the medium-complexity refinery reduces emissions by 380 kt $CO_2$/y, or 11 %. These findings highlight the potential for further $CO_2$ reductions by fully replacing refinery gas fuel with low-carbon hydrogen. Future research should focus on reallocating surplus refinery fuel gas to non-combustion processes.

Finally, the results of this study can serve as a guide for the decarbonization of oil refineries with similar complexity worldwide. This can help inform future investment decisions and strategic planning in the pursuit of $CO_2$ neutrality.

## CRediT authorship contribution statement

**Erik López-Basto:** Writing – review & editing, Writing – original draft, Visualization, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Gijsbert Korevaar:** Writing – review & editing, Validation, Supervision, Methodology. **Samantha Eleanor Tanzer:** Writing – review & editing, Visualization, Validation, Supervision, Methodology. **Andrea Ramírez Ramírez:** Writing – review & editing, Validation, Supervision, Methodology, Formal analysis, Conceptualization.

## Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:

The main author would like to thank Ecopetrol S.A., which provided a personal stipend as a loan scholarship to pursue postgraduate studies. The other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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The views expressed in this paper do not necessarily reflect those of Ecopetrol S.A.

Supplementary data, material, and calculations to this article can be found online at: https://doi.org/10.4121/cbcc8bb9–7a8b-4041-b60b-360110a65bab

## Appendix A

**Table A1**
Hydrogen consumption in the refining process. Source: based on RIS Ecopetrol (2021).

| | | | | |
|---|---|---|---|---|
| | | High complexity refinery | | |
| Feedstock | Gasoil. | HSD + HSHN from FCC. | High sulfur diesel. | HSHN & HSLN from FCC. |
| Application | HCK | HDT. ULSD | HDT. ULSD | NHT |
| $H_2$/Feed Hydrocarbon (SCFB) | 2040 | 540 | 587 | 168 |
| $H_2$/Feed Hydrocarbon (t $H_2$/kbbl) | 5.01 | 1.29 | 1.4 | 0.4 |
| | | Medium complexity refinery | | |
| Feedstock | Gasoil. | HSD | HSD. | HSN from FCC. |
| Application | HCM | HCM | HDT. ULSD | NHT |
| $H_2$/Feed Hydrocarbon (SCFB) | 1041 | 769 | 405 | 50 |
| $H_2$/Feed Hydrocarbon (t $H_2$/kbbl) | 2.48 | 1.83 | 0.97 | 0.12 |

SCFB: standard cubic feet per barrel. HCK: Hydrocracking, HDT: Hydrotreatment, NHT: Naphtha hydrotreater, HCM: Medium severity hydrocracker, HSD: High sulfur diesel, ULSD: Ultralow sulfur diesel, HSHN: High sulfur heavy naphtha, HSLN: High sulfur light naphtha, HSN: High sulfur naphtha.

## Appendix B

The techno-economic parameters of the low-carbon hydrogen production technologies used in the modeling process are presented in Tables B1 to B5.

**Table B1**
Techno-economic data for SMR + CC technology.

| | High complexity Value | Medium complexity Value | Reference |
|---|---|---|---|
| Capacity SMR, t $H_2$ /d | 238 | 79 | Source: Technical data sheets / RIS Ecopetrol (2021) |
| Feedstock (natural gas), GJ NG/ t $H_2$ | 133.4 | | RIS Ecopetrol (2021) |
| Electricity consumption, MWhe/ t $H_2$ | 0.36 | | RIS Ecopetrol (2021) |
| HPS net generation kg /t $H_2$ | 7.3 | | RIS Ecopetrol (2021) |
| Reformer fuel gas consumption, GJ /t $H_2$ | 26.8 | | RIS Ecopetrol (2021) |
| Reformer tail gas consumption, GJ /t $H_2$ | 47 | | RIS Ecopetrol (2021) |
| Emission factor, kg $CO_2$/kg $H_2$ | 9.31 | | SIGEA 2019 |
| Capex, € $_{2020}$/t $H_2$ | 7505 | | GDR, (2021) |
| Annual fix Opex | 3 % Annual capex | | GDR, (2021) |
| Start in service | 2015 | 2010 | |
| Economic Lifetime, years | 25 | | |
| ***Retrofit, year*** | 2040 | 2035 | |

(*continued on next page*)

**Table B1** (*continued*)

| | High complexity Value | Medium complexity Value | Reference |
|---|---|---|---|
| Capacity after retrofit, t $H_2$ /d | 238 | 79 | |
| Retrofit Investment | 60 % of the original Capex | | GDR, (2021) |
| Annual fix Opex | 5 % Annual Capex | | GDR, (2021) |
| Economic lifetime, years | 25 | | |
| $CO_2$ capture Unit | | | |
| Technology | **Chemical absorption ADIP-X** | | |
| Application | SMR. Out stream of water gas shift reactor | | |
| Capture efficiency | 95 % | | Meerman (2012) |
| Low-pressure steam consumption, GJ/t $CO_2$ captured | 1.97 | | Meerman (2012) |
| Electricity consumption, kWh/t $CO_2$ captured | 2.1 | | Own calculation from Hysys simulation based on Meerman's 2012 study. |
| Carbon footprint, kg $CO_2$ /t $CO_2$ captured | 111 | | Own calculation |

ADIP-X: 45 %wt. MDEA conc. and 5 %wt. Piperazine conc.

*Renewable electricity and water electrolyzer.*

Two sources of renewable energy are included in this article. Types and capacity are shown in Table B2

**Table B2**
Techno-economic data for renewable energies. Source: GG&BE (2021) and Ioannis Tsiropoulos et al. (2018).

| Process | Parameter | Both refineries | Reference |
|---|---|---|---|
| Wind generation | Capacity factor | 41 % | GG&BE (2021) |
| | Capex, €/kW (2020) | 1310 | Ioannis Tsiropoulos et al. (2018) |
| | Fix Opex | 3 % annual capex | Ioannis Tsiropoulos et al. (2018) |
| | Lifetime, years | 25 | Ioannis Tsiropoulos et al. (2018) |
| | LCOE, €/MWh | 50 | GG&BE (2021) |
| Photovoltaic generation | Capacity factor | 19.5 % | GG&BE (2021) |
| | Capex, €/kW (2020) | 830 | Ioannis Tsiropoulos et al. (2018) |
| | Fix Opex | 1.7 % annual capex | Ioannis Tsiropoulos et al. (2018) |
| | Lifetime, years | 25 | Ioannis Tsiropoulos et al. (2018) |
| | LCOE, €/MWh | 68 | GG&BE (2021) |
| Transport | | 6 % of the total electricity price (3.9 €/MWh) | Based on XM report, 2022 |
| Commercialization | | 9 % of the total electricity price (5.8 €/MWh) | Based on XM report, 2022 |

No electricity grid losses and restrictions have been taken into account in this calculation.

Tables B3 and B4.

**Table B3**
Techno-economic data for a PEM electrolyzer.

| | Value | Reference |
|---|---|---|
| Technology | PEM | |
| Efficiency (including BOP) 2022, kWhe/kg $H_2$ | 62.1 | Irena (2018) |
| Capex (including BOP*) 2022, €/kW | 1505 | IEA, (2023) |
| Annual fix Opex | 2 % of annual capex | Ioannis Tsiropoulos et al. (2018) |
| Lifetime, years | 20† | Ioannis Tsiropoulos et al. (2018) |
| Oxygen supply price (pipeline), €/t | 22 | Based on Linde prices 2022 |

BOP: Balance of Plant (Auxiliary equipment). * 18.9 % of additional cost for BOP Source: Green Hydrogen Production. Ecopetrol pilot scale test (2022).
† 10 years for Electrolyzer stacks.

*Electricity from Biomass to power electrolyzers.*

**Table B4**
Techno-economic data for Biomass-electricity.

| | Value | Reference |
|---|---|---|
| Feedstock. Biomass | | |
| Tree species. | Eucalyptus Calmaldulensis* | Díaz F & Molano M. (2001) |
| Low heating Value, MJ/kg. | 18.5 | Arrieta et al. (2016) |
| $CO_2$ capture performance, t $CO_2$ / ha y. | 21.7 | Díaz F & Molano M. (2001) |
| Area | 5000 ha max. Eucalyptus Calmaldulensis. | |
| Biomass Growth-to-Consumption Cycle Ratio, year. | 4.1 | |
| Price, (€/ha) | 411 | Díaz F & Molano M. (2001) |
| Price, €/t dry biomass | 63.7 | Boston Consulting Group (2021) |
| Annual Capex, USD/ha | 432 | Díaz F & Molano M. (2001) |
| Annual fix Opex | 3 % of annual capex | |
| Feedstock capacity, t/d dry biomass | 1849 | Ecopetrol. GDR (2021) |
| Wet biomass, % moisture content | %… | Brau & Morandin (2014) |
| Dry biomass EP, % moisture content | 10–20 % | Brau & Morandin (2014) |
| Wet biomass/ dry biomass mass ratio | 1.4 | Own calculation |
| Upstream emission factor, kg $CO_2$ / t dry biomass | 126.5 | Own calculation |

(continued on next page)

**Table B4** (*continued*)

| | Value | Reference |
|---|---|---|
| Power plant | | |
| Factor, t dry biomass / MWe | 1.4 | Boston Consulting Group (2021) |
| Emission factor, kg $CO_2$ / t dry biomass | 1953 | Arrieta et al. (2016) |
| Emission factor, t $CO_2$ / MWe | 1.5 | GDR (2021) |
| Capacity Max, MW | 64 | |
| Availability Plant factor | 82 % [82–92 %] | GDR (2021) |
| Capex €/kW installed (2020) | 3400 | Boston Consulting Group (2021) |
| Fix Opex, | 2 % of annual capex | Ioannis Tsiropoulos et al. (2018) |
| Lifetime, years | 25 | Ioannis Tsiropoulos et al. (2018) |

[*] Based on the location of both refineries, the closer area is the Cesar department. 26–29C; 35–3000 m.a.s.l. Rain falling: 1000 - 1300 mm yearly.
EP: Eucalyptus pellets.

*Biomass gasification.*

**Table B5**
Techno-economic data for biomass gasification + CC. $H_2$ production.

| | Value | Reference |
|---|---|---|
| Biomass gasification – $H_2$ plant | | |
| Technology | Indirect gasification | |
| Feedstock, t dry biomass / t $H_2$ | 10 | Brau & Morandin (2014) |
| Electricity demand, MWhe / t/d $H_2$ | 0.2 | Brau & Morandin (2014) |
| Steam demand, t steam / t $H_2$ | 11.6 | Brau & Morandin (2014) |
| Capacity Max., t $H_2$/d | 60 | |
| Capex €/ t $H_2$ installed (2020) | 14,802 | Based on GDR (2021) |
| Fix Opex, | 2 % of annual capex | Ioannis Tsiropoulos et al. (2018) |
| Lifetime, years | 25 | Ioannis Tsiropoulos et al. (2018) |

$CO_2$ capture Unit

| | | |
|---|---|---|
| Technology | **Chemical absorption MEA** | **Reference** |
| Application | Biomass gasification and fluid bed boiler flue gas* | |
| Investment Cost MEA, € 2020/t $CO_2$ | 79,6 | Irena (2018) |
| Capture efficiency | 90 % | |
| Low-pressure steam consumption, GJ/t $CO_2$ captured | 2.7 | SINTEF (2017) |
| Electricity consumption, kWh/t $CO_2$ captured | 36.6 | SINTEF, (2017) |
| Carbon footprint, kg $CO_2$ /t $CO_2$ captured | 157 | Own calculation |
| Lifetime, years | 20 | Ioannis Tsiropoulos et al. (2018) |
| * *Considering $CO_2$ average conc. 17.7 % vol* | | |

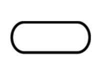
$CO_2$ compression, drying, transportation, and injection. Source

| Incremental Cost | **Value, €/ t $CO_2$** | **Reference** |
|---|---|---|
| Cartagena (HC) | 28.7 | Based on (Yáñez et al., 2020) and (Younis et al., 2023) |
| Barrancabermeja (MC) | 14.1 | |

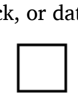
**Considering onshore storage, pipeline transportation, and distances less than 200 km for HC and less than 10 km for MC.*

## Appendix C. Linny-R Model. Oil refineries model

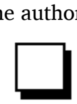
Linny-R uses symbols to build a representation of a system.



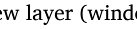
Feedstocks and products representation. It could be a source, sink, stock, or data type.



Process. Each process is considered as an actor, assigning a name by the author.



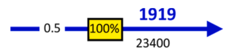
Process cluster: A layer that contains a group of processes or equipment. Clicking on this icon opens a new layer (window).



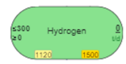
Connectors. Mass and energy streams.


The first number corresponds to the linear ratio. The number in the yellow square corresponds to the percentage allocated from the cost of production.

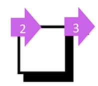
When the stream is activated, the color changes from black to blue, and numbers with mass flow and cost show are displayed.



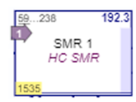

blue number corresponds to the amount of energy or mass that goes to the next process; and below is the cost generated.




Left side numbers correspond to low and high boundaries (limits). The right side number corresponds to the actual amount of this product or feedstock and is below the measuring units. At the bottom on the left side is the calculated production cost, and on the right side, the price assigned is displayed.




Purple arrows represent the number of connections that come or go to other layers (clusters)




Left upper corner numbers are the low and high capacity of the process. The right upper corner number is the used actual capacity. The left lower corner number is the cost of production. In the middle of the square appears the name of the process in black, and below in purple italic form font the actor's name.

The utility block is modeled in more detail reaching the level of equipment groups, composed of natural gas power and a steam generation process based on a combined cycle scheme (NGCC), which includes electricity generator-gas turbines accoupled to Heat Recovery Steam Generation (HRSG), conventional gas-fired boilers, and condensing and back-pressure steam turbines accoupled to an electricity generator. Additionally, in the utility block, the Imported natural gas is adjusted to be used as a feedstock in the hydrogen production using the Steam Methane Reformer technology (SMR). Finally, all the gas fuel required in the process furnaces and steam boilers is produced in the section by blending the recovered refinery off-gas with a small portion of the imported natural gas. Fig. C1 shows a screenshot of the utility block in Linny-r.

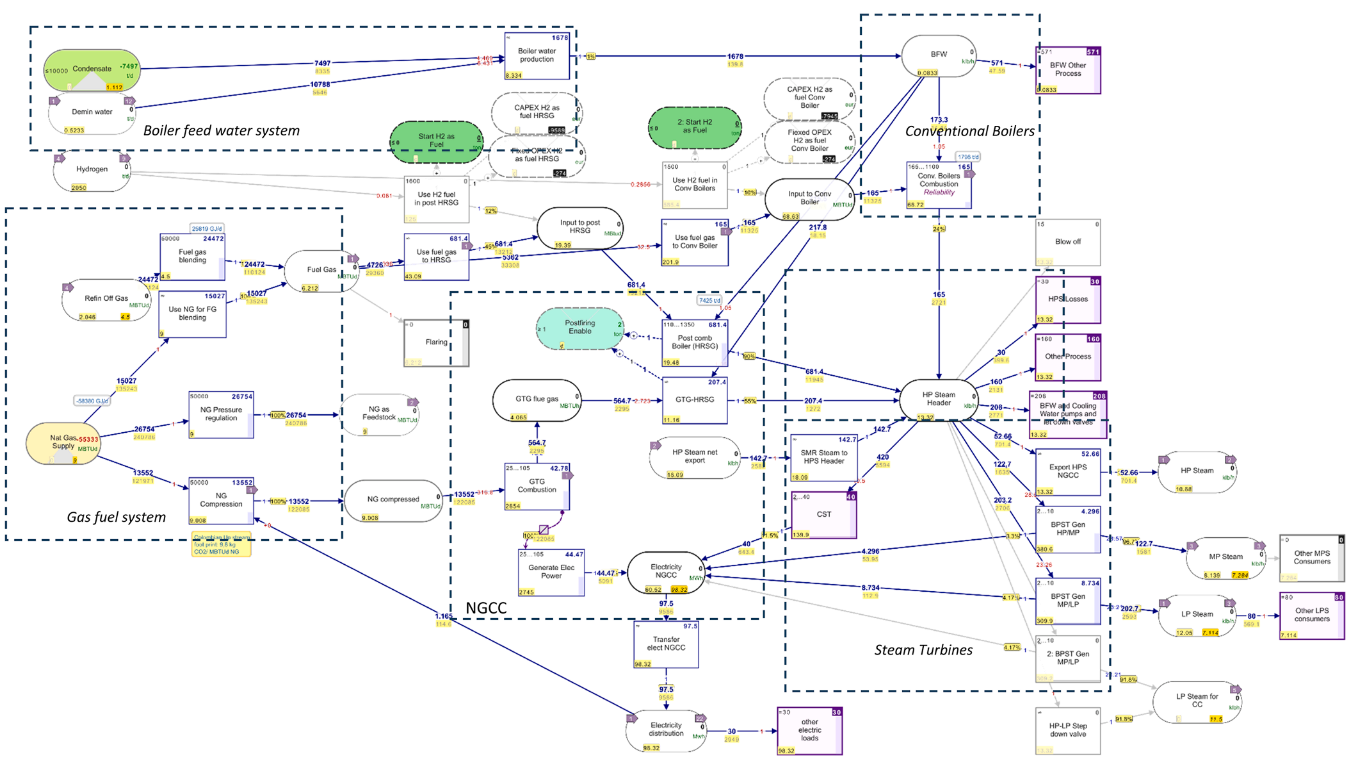



**Fig. C1.** Utility block in Linny-r.

The Oil refining process block is composed of two sub-blocks, one the high Complexity process (Cartagena refinery) and the second the medium complexity process (Barrancabermeja refinery). Process, yields, and utility demands can be found in the repository. Fig. C2 shows a screenshot of the high complexity oil refining block in Linny-r.

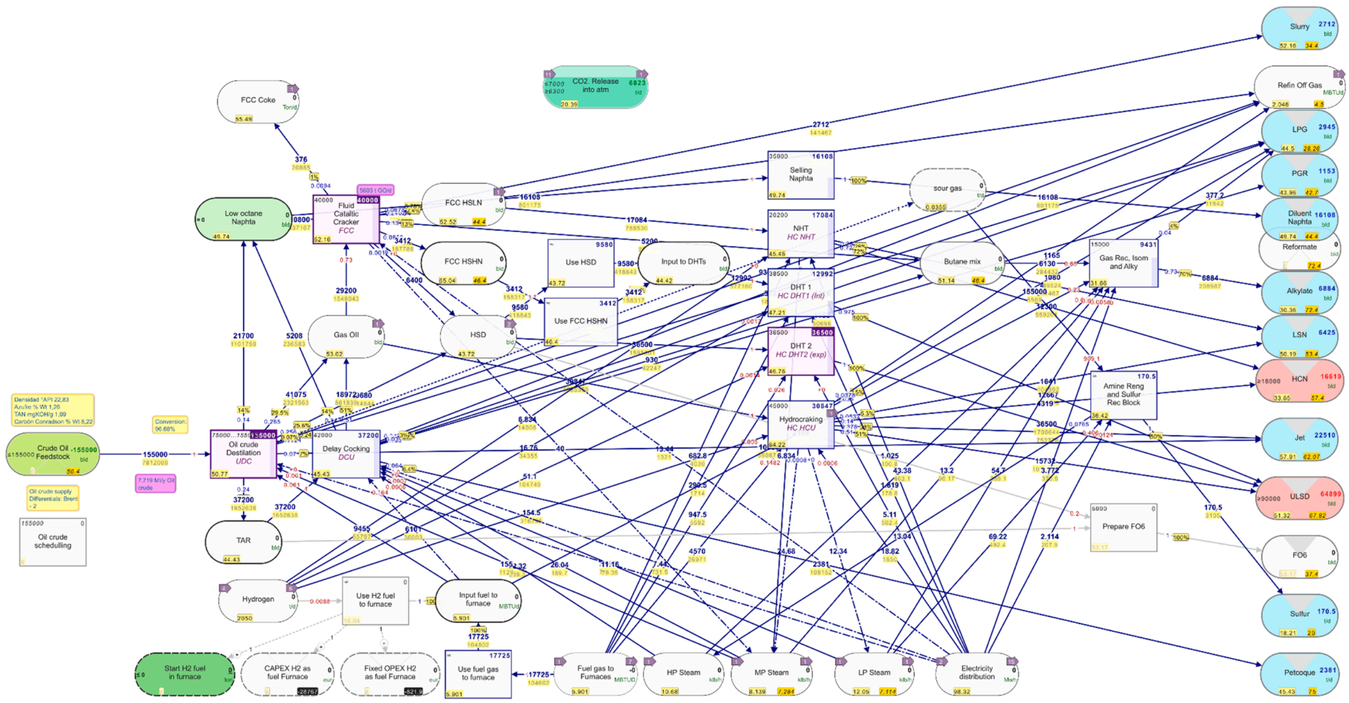



**Fig. C2.** Oil Refining block Linny- R.

The low-carbon hydrogen technologies block involves the technologies selected after the screening process are presented in **Figures** Fig. C2, C3, C4, **and** C5.

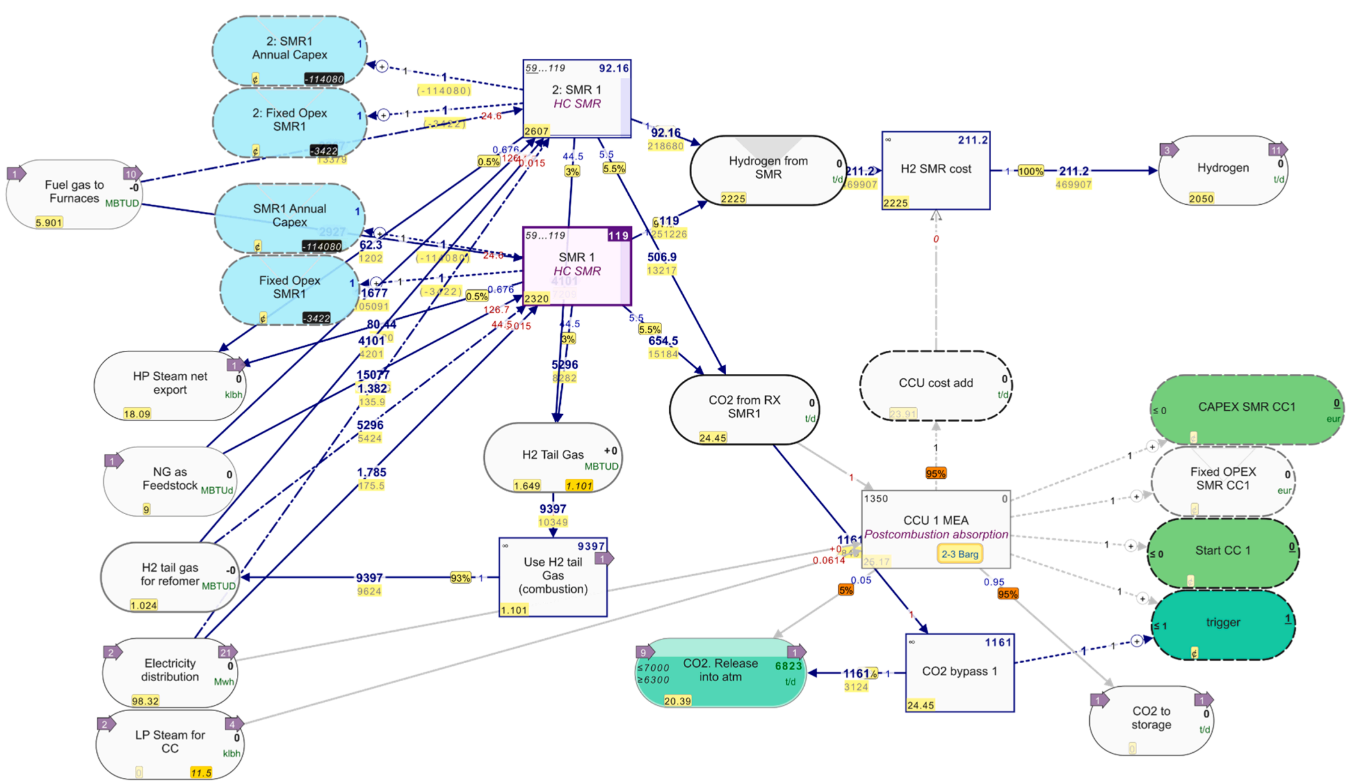



**Fig. C3.** Steam methane reforming + CC block in Linny-r.

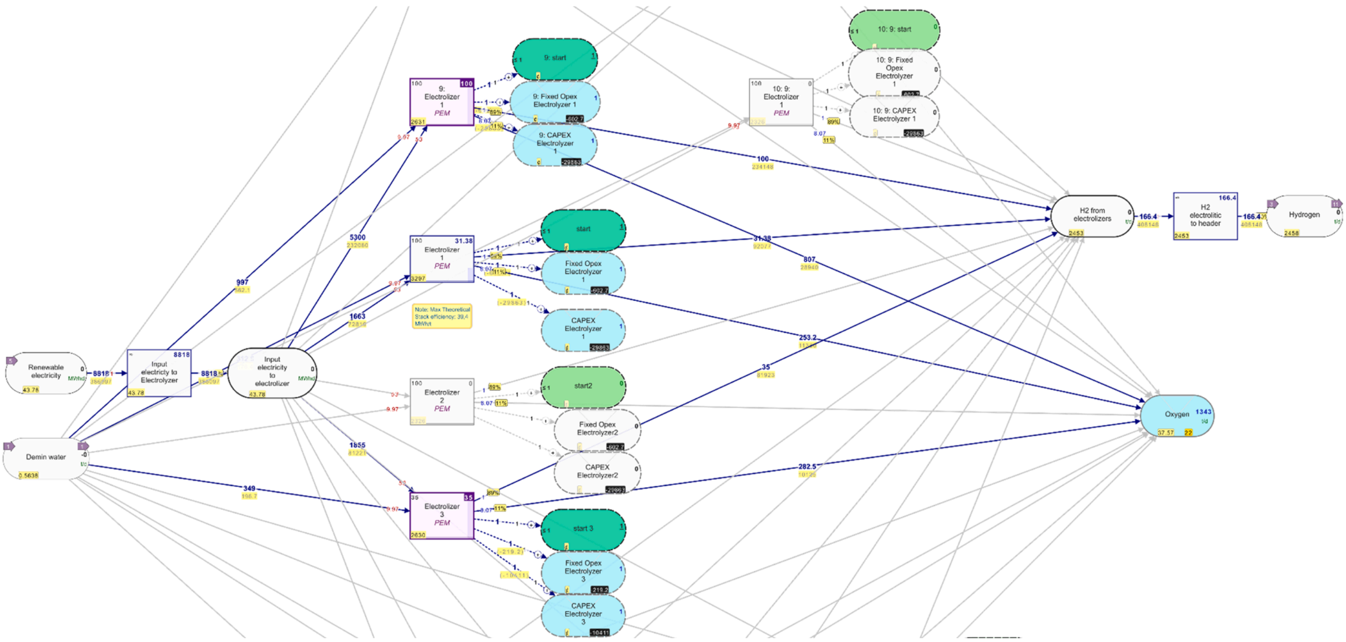



**Fig. C4.** Water electrolysis block in Linny-r.

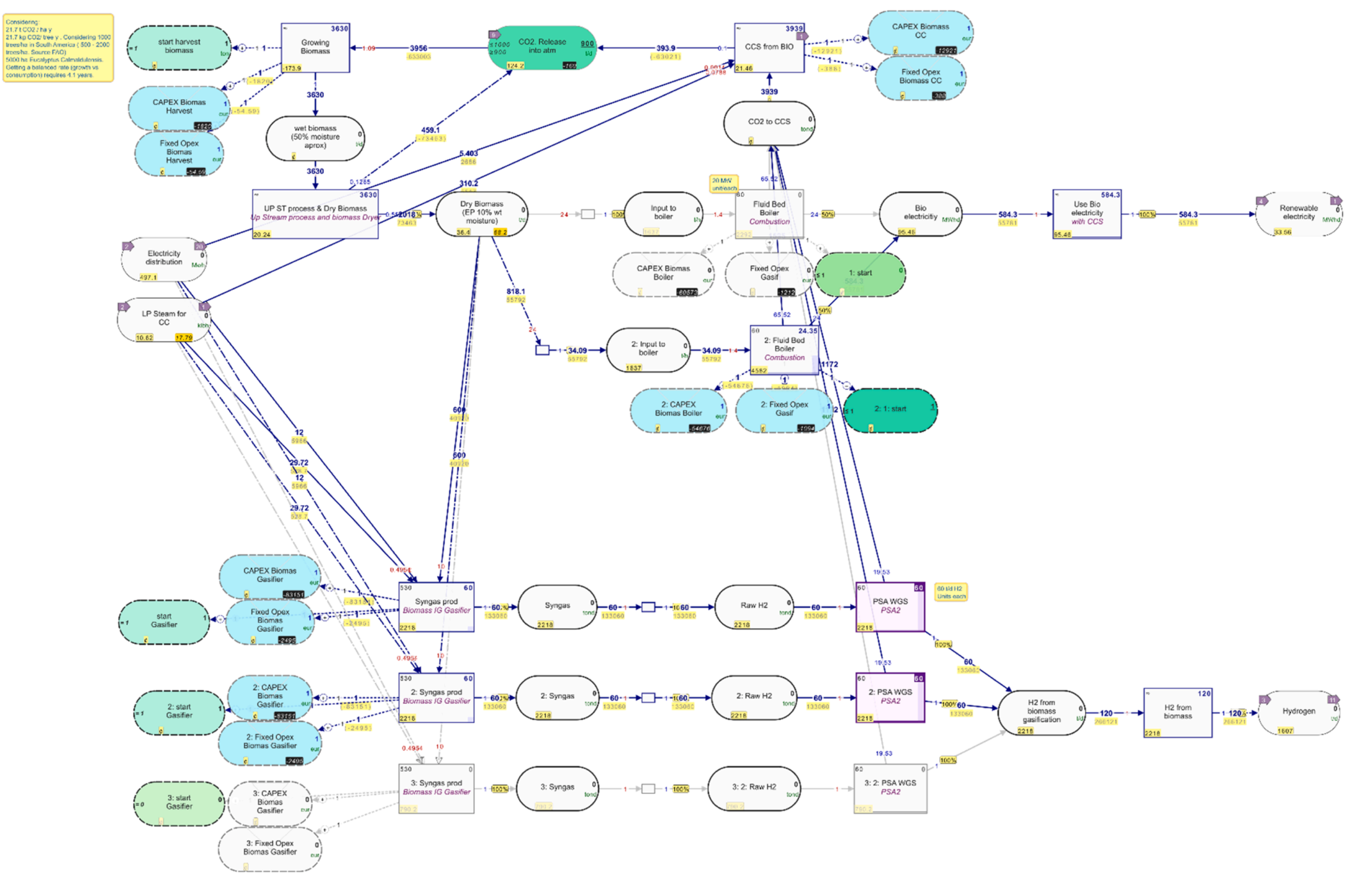



**Fig. C5.** Biomass-based low carbon hydrogen + CC block in Linny-r.

## Data availability

Data will be made available on request.

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