Role of flexible contract design in unlocking Power-to-X projects

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Abstract—**Power-to-X is seen as a promising option for decarbonising hard-to-electrify sectors, yet its scalability is limited by challenges such as mismatched contractual expectations between suppliers and offtakers, hindering the path to final investment decision. Pricing flexibility into green hydrogen offtake contracts can address the intermittency of renewable energy and help address these issues. While flexible offtake contracts have been studied in the literature, their impact on economic feasibility has not been thoroughly investigated. We explore strategies to increase flexibility in green hydrogen contracts by proposing adaptive pricing structures that consider supply shortages, surpluses, delivery horizons, and hydrogen classifications. Our analysis shows that flexible offtake contracts improve the bankability of green hydrogen projects. By accounting for delivery variability and low-carbon hydrogen production, these contracts allow offtakers to better express their true need for delivery certainty, allowing to share the risk of renewable intermittency, thereby de-risking investments.**

Index Terms—**Power-to-X, Hydrogen offtake contract, Flexibility, Renewable energy integration, Carbon intensity**

I. INTRODUCTION

Decarbonizing hard-to-abate sectors, i.e., industries that currently depend on fossil fuels and face significant technical and economic hurdles in reducing carbon emissions, is essential for achieving climate goals. To address this, electrification solutions powered by renewable energy sources have received growing attention [1]. However, this approach is challenged by the intermittent nature of renewable energy generation. In this context, hybrid power plants, which integrate one or more renewable energy sources with energy storage and conversion systems, have emerged as viable solutions to provide a stable supply to support these energy-intensive industrial processes. In particular, hybrid Power-to-X (PtX) plants, enable the production of green hydrogen and e-fuels from renewable electricity through water electrolysis, to replace fossil fuels in industries such as refineries, steel production, fertilizers, and heavy transport [2].

At the European level, the REDIII directives clarify the rules for the production of Renewable Fuel of Non-Biogenic Origin (RFNBO) [3] and set ambitious production targets. To support this substantial shift from fossil to renewable hydrogen, funding mechanisms such as the Hydrogen Bank [4] have been initiated to bridge the price gap between RFNBO-compliant and fossil-based hydrogen, which is currently more than 3 to 1 [5].

Despite these ambitious targets and the associated funding and regulatory framework supporting renewable hydrogen production, the PtX sector faces severe scalability challenges, which have recently led to the freezing or withdrawal of several previously announced projects. A notable example is the recent results of the Danish Energy Agency's offshore wind auction, where hydrogen production was considered a viable option for utilizing surplus electricity due to overplanting. However, no bids were submitted, mainly due to the auction design and uncertainties surrounding hydrogen offtake agreements and associated transport infrastructure [6].

There are several reasons for this 'slow start' in securing hydrogen offtake agreements, including price mismatch between RFNBO-compliant and fossil-fuel based hydrogen, ambitious RFNBO production and consumption targets with a tight schedule, and significant technical challenges associated with hydrogen supply chain. Another key reason is the mismatch in offtake contract expectations between the producers and consumers. Buyers expect a steady, continuous supply, similar to the hydrogen production achieved through conventional steam methane reforming, which operates at 8,300 full-load hours [7], and expect from RFNBO-hydrogen suppliers to offer prices competitive with fossil-based alternatives. Meanwhile, hybrid PtX plant developers prioritize flexibility to address the operational challenges of producing RNFBO-compliant hydrogen from intermittent renewable energy sources. Although a mature global green hydrogen market and supporting grid infrastructure could ease these operational challenges, this is not expected to materialize in the near future. For example, the first phase of the hydrogen pipeline between Denmark and Germany, which is the first large-scale hydrogen pipeline planned in Europe, is planned for 2030 [8]. Thus, in the current context, ensuring a steady hydrogen supply requires hybrid PtX plant developers to invest in overcapacity for hydrogen production and storage, or to secure a broader portfolio of renewable energy sources to guarantee uninterrupted availability. However, these investments can undermine the project's economic viability or technical feasibility. Additionally, uncertainty around long-term hydrogen pricing and market dynamics can amplify developers' reluctance to commit to projects reliant on rigid offtake structures [9]. Conversely, industrial end-users expect steady hydrogen supply to support their operations. Flexible

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contracts may force buyers to adjust their operations to manage fluctuations in supply, leading to a loss of confidence in such contracts and potentially widening the price expectation gap. Therefore, transparent dialogue is crucial to align expectations between producers and buyers, and facilitate the adoption of flexible hydrogen offtake agreements.

Similar flexibility considerations have been addressed for renewable generation, where a hybrid market structure combining long-term Power Purchase Agreements (PPAs) and short-term markets has been proposed to increase the flexibility of renewable electricity assets [10]. For example, Enel has offered options for hybrid PPAs for hybrid power plants consisting of solar farms coupled with battery storage [11]. Yet, there is limited work in the literature on the design of flexible offtake agreements for hybrid PtX plants. The authors in [12] explore optimal day-to-day operation strategies for a hybrid PtX plant under varying electricity prices and renewable resource availability, while also taking into account different hydrogen contract design parameters. In particular, aspects such as delivery periods, hydrogen pricing, and volume commitments are considered. The paper concludes that these contract-related factors play a significant role in shaping the economic viability of hybrid PtX plants. However, while the study highlights the importance of these contract parameters definition, it maintains a fixed pricing mechanism that lacks the flexibility to accommodate shortages or surpluses arising from the intermittent nature of renewable energy production. Moreover, it does not explore the potential for low-carbon hydrogen production, i.e., the production of hydrogen by electrolysing low-carbon electricity, resulting in a carbon intensity lower than 3.38 kgCO_2/kgH_2 [13]. The authors in [14] examine how hydrogen classification rules and subsidies influence plant sizing and optimal PPA sourcing strategies. Using a two-stage stochastic model, the study incorporates uncertainties in renewable energy production and day-ahead electricity prices across various regulatory frameworks. The findings highlight that temporal correlation and flexibility in producing low-carbon hydrogen significantly affect the energy sourcing strategy and the overall levelized cost of hydrogen (LCOH) for the plant. Their study focuses on a fixed-demand hydrogen offtake agreement without considering parameters related to the structure of the contract, such as the delivery horizon or financial mechanisms to account for surplus or shortfall in the delivery. Although the aforementioned studies highlight the importance of flexibility in contract design, their approach remains limited and does not allow for flexibility in volume delivery.

This work aims to fill this gap in the literature and contribute to unlocking hybrid PtX projects by addressing the following question: *How does flexibility in hydrogen offtake contracts impact PtX investment decisions?* We consider several strategies to increase the flexibility of hydrogen offtake contracts, closely aligning them with the intermittent nature of renewable energy production. The proposed hydrogen supply contract structure is designed to account for a specified volume, delivery horizon, and hydrogen pricing, including a two-sided penalty structure that allows for surplus and shortfall in the delivery of hydrogen, inspired by imbalance pricing in electricity markets. While this flexibility is intended to benefit producers, it could be extended in future work by extending flexibility to buyers through financial contracts or options. For example, such flexibility could include the ability to reduce contracted volumes to avoid the risk of being locked into high prices in the future while competitors are able to secure lower prices. The contributions of this work are threefold:

First, we propose a financial hydrogen offtake contract structure which differentiates prices according to surpluses and shortfalls over a contracted time period, allowing some deviations in deliveries due to the intermittent nature of renewable energy. The framework aims to facilitate the design of mutually-beneficial hydrogen offtake agreements. Second, we develop a structured techno-economic model of hybrid PtX plants, accounting for the hydrogen offtake contract structure. This model provides actionable insights to plant developers into techno-economic feasibility of PtX projects. Third, we empirically demonstrate the critical role of flexible hydrogen offtake contracts in reducing investment risks and accelerating the scale-up of green hydrogen production. Numerical results show that the Net Present Value (NPV) of PtX projects is improved by including flexibility, and this trend is seen for varying hydrogen contracted price and reference year used.

This remainder of this paper is organized as follows: Section II introduces the proposed offtake contract structure and techno-economic model, Section III presents the case study, serving as the foundation for the numerical analysis in Section IV, and, finally, Section V concludes this work.

II. TECHNO-ECONOMIC MODEL OF HYBRID PTX PLANT

A. *Overview of energy flows*

As illustrated in Fig. 1, this study considers a hybrid PtX plant that integrates an electrolyzer with co-located wind and solar farms, drawing electricity from these renewable sources (p_t^W, p_t^{PV}) or the grid (p_t^{grd}) to produce hydrogen (h_t^{ely}). To help mitigate the intermittence of renewable energy sources and electricity price volatility, the plant includes a hydrogen storage tank. As the focus of this study is not the plant sizing, we assume that the capacities of these assets are predetermined. The hydrogen supplied to the offtaker, as outlined in the bilateral contract detailed in Section II-C, is sourced either directly from the electrolyzer or from the storage tank. The operational equations governing the electrolyzer, storage tank, and energy flow balances are provided in Appendix C-Appendix E.

B. *RFNBO and low-carbon hydrogen classification*

As shown in Fig. 1, the electrolyzer production can be classified as RFNBO-compliant ($h_t^{ely,RF}$) or low-carbon ($h_t^{ely,LC}$) hydrogen, depending on whether it meets the requirements set in the RFNBO Delegated Act [15]. As a result, the two hydrogen production streams from the electrolyzer are separated based on their origin, such that:

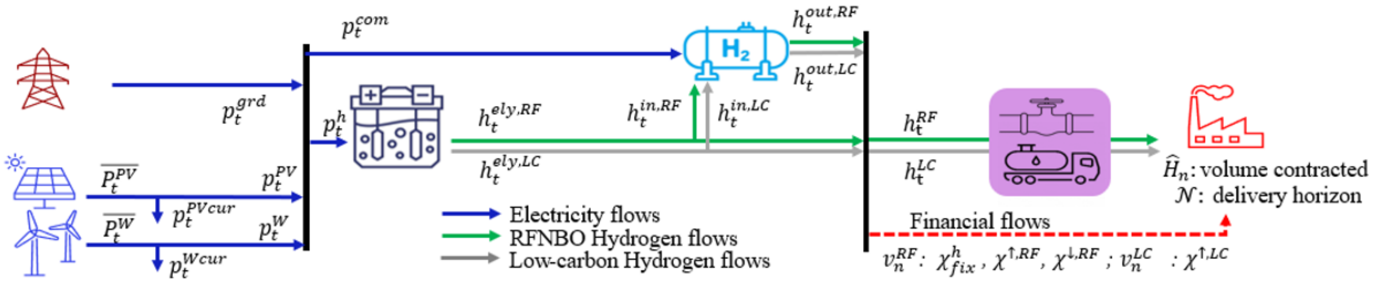

Fig. 1. Hybrid PtX plant model overview

$$h_t^{ely} = \sum_{c \in \{RF,LC\}} h_t^{ely,c}, \quad \forall t \in \mathcal{T} \tag{1}$$

These two categories of hydrogen may be priced differently in a purchase contract, as the offtaker might assign distinct values to each. While some offtakers may require a stricter threshold to ensure lower carbon intensity of their industrial process, the remainder of this paper adopts the RFNBO-compliant threshold set in the RFNBO Delegated Act. The first requirement of the RFNBO Delegated Act enforces a carbon intensity threshold $\bar{\Gamma}$ for the hydrogen production over a set horizon $\mathcal{S}^{RF}$ (e.g. monthly up to 2030 and hourly after 2030 according to the RFNBO Delegated Act [15]). The carbon intensity threshold for the hydrogen, expressed in $kgCO_2/kgH_2$ here, ensures compliance with the regulation and limits the grid import p_t^{grd}, characterized by a time-step wise grid carbon intensity, Γ_t^{grd}, expressed in $kgCO_2/MWhe$. As hydrogen production from co-located renewable energy sources does not contribute to the plant's carbon intensity, only the grid imports are considered, such that:

$$\bar{\Gamma} \sum_{t \in \mathcal{T}^{RF}} h_t^{ely} \geq \sum_{t \in \mathcal{T}^{RF}} \Gamma_t^{grd} p_t^{grd}, \qquad \forall \mathcal{T}^{RF} \in \mathcal{S}^{RF} \tag{2}$$

In addition, hydrogen produced using non-renewable electricity from the grid is not considered RFNBO-compliant and is classified as low-carbon as long as Constraint (2) is met. This low-carbon hydrogen quantity is defined as:

$$h_t^{ely,LC} = (1 - \Delta_t^{grd}) \frac{p_t^{grd}}{\kappa^{e \to h}}, \qquad \forall t \in \mathcal{T} \tag{3}$$

where Δ_t^{grd} represents the renewable share in the grid, and $\kappa^{e \to h}$ the electrolyzer's efficiency rate.

C. Hydrogen offtake contract design

The hydrogen offtake contract considered specifies the base-load volumes of RFNBO-compliant hydrogen $\widehat{H}_n$ to be supplied over each delivery period $n \in \mathcal{N}$. The seller is remunerated at a contracted price χ^{fix} for this base-load production.

The proposed hydrogen offtake contract is tailored to support flexible hydrogen production, accounting for volume surpluses and shortfalls, as well as multiple hydrogen streams. To address potential volume shortfalls and surpluses in the contract design, our approach draws inspiration from the two-price structure of balancing electricity markets. In the event of a shortfall, i.e, the RFNBO-compliant volume v_n^{RF} supplied over a delivery period n is lower than the contracted volume $\widehat{H}_n$, the buyer must be compensated at a specified price $\chi^{\downarrow^{RF}} \geq \chi^{fix}$. Similarly to two-price balancing electricity markets, the difference between the base-load and shortfall prices incurs a penalty for the seller. Conversely, the purchase agreement specifies a price $\chi^{\uparrow^{RF}} \leq \chi^{fix}$ that the seller receives for potential surplus RFNBO-compliant hydrogen volume. The difference between the base-load and surplus price, therefore, represents an opportunity loss for the seller. Additionally, low-carbon hydrogen can be exported at a lower contracted price $\chi^{\uparrow^{LC}} \leq \chi^{\uparrow^{RF}}$. However, to ensure feasibility for the buyer, the contract specifies an upper-bound $\bar{H}_n$ on the total volume surplus, such that:

$$\sum_{c \in \{RF,LC\}} v_n^c \leq \bar{H}_n, \quad \forall n \in \mathcal{N} \tag{4}$$

As a result, the sellers' fixed and balancing annual revenues are expressed respectively as:

$$r_y^{fix} = \sum_{n \in \mathcal{N}} \chi^{fix} \widehat{H}_n, \qquad \forall y \in \mathcal{Y} \tag{5}$$

$$\begin{aligned} r_y^{bal} = \sum_{n \in \mathcal{N}} \big[& \chi^{\uparrow^{RF}} (v_n^{RF} - \widehat{H}_n)^+ \\ & - \chi^{\downarrow^{RF}} (\widehat{H}_n - v_n^{RF})^+ + \chi^{\uparrow^{LC}} v_n^{LC} \big], \qquad \forall y \in \mathcal{Y} \end{aligned} \tag{6}$$

This mechanism is further illustrated through a fictitious hydrogen delivery schedule in Fig. 5, Appendix F.

D. Techno-economic feasibility analysis

The objective of the proposed techno-economic model is to examine the impact of the hydrogen purchase contract on plant operations and project feasibility, highlighting the importance of integrating contract design considerations at the early stages of project development. To evaluate the techno-economic feasibility of the project, we analyze its NPV. Whilst annual revenues or Levelized Cost of Hydrogen (LCOH) have commonly been used as economic performance indicators in the literature, the proposed model focuses on the NPV since it provides a comprehensive metric that reflects the long-term economic viability of the plant. The use of this metric differs from LCOH in that it directly incorporates the hydrogen contract structure into the economic assessment, enabling a more holistic consideration of feasibility rather than focusing solely on reducing the production costs of the plant.

As a result, the techno-economic feasibility problem of the hybrid PtX power is formulated as:

$$\max_{\substack{r_y^{fix}, r_y^{bal} \\ o_y^{var}, c_y^{grd}}} \quad -I_0 + \sum_{y \in \mathcal{Y}} \frac{\mathrm{CF}_y}{(1+\rho)^y} \tag{7}$$

$$\text{s.t} \quad \text{Eqs. } (1)-(3),\ (4)-(6),\ (14)-(27) \tag{8}$$

$$CF_y = r_y^{fix} + r_y^{bal} - c_y^{grd} - o_y^{var} - O^{fix}, \forall y \in \mathcal{Y} \tag{9}$$

This optimization problem maximizes the NPV of the project in (7), consisting of the initial investment I_0 and sum of annual cash flows CF_y at a discount rate ρ, subject to Constraint (8) enforcing RFNBO-compliant hydrogen requirements, the hydrogen purchase contract structure, and the energy flow balance of the plant. Constraint (9) defines the total annual cash flows CF_y as the sum of annual fixed contracted revenues r_y^{fix} and annual balancing revenues r_y^{bal} from the hydrogen offtake contract, fixed and variable OPEX, O^{fix} and o_y^{var}, minus the annual cost of importing electricity from the grid through the day-ahead market, c_y^{grd}, at a price equal to the day-ahead market price λ_t^{DA} for a considered time-step t plus the TSO tariff grid λ^{TSO}. The cost parameters and variables are further described in Appendix B.

III. CASE STUDY DESCRIPTION

A. Reference case

The GreenH2Atlantic project [16] serves as an illustrative case study, representing a real-world hybrid PtX plant. Located in Sines, Portugal, it aims to produce green hydrogen for use in a refinery, which is considered as the sole hydrogen offtaker. The plant design and annual offtake volumes are predefined, as described in Appendix A. This analysis provides a proof of concept of the proposed methodology for enhancing hydrogen offtake contract flexibility and evaluating the impact of contract structure on project feasibility.

B. Hydrogen offtake contract configurations

This analysis examines several offtake contract configurations detailed in Table I, representing different combinations of the contract parameters, namely balancing, i.e, surplus and shortfall offtake prices (expressed relative to the base-load price), duration of contracted delivery periods, and low-carbon hydrogen clause (specifying whether or not the offtaker accepts low-carbon hydrogen), each of which captures a distinct dimension of offtake flexibility. Configuration A represents an inflexible contract structure, placing the full risk of managing renewable energy intermittence on the hydrogen producer. In contrast, Configurations B through D progressively introduce flexibility, gradually shifting this risk from the producer to the offtaker.

TABLE I
OFFTAKE CONTRACT FLEXIBILITY PARAMETERS DEFINITION.

Configurations:	**A**	**B**	**C**	**D**
Flexibility	No	Partial	Large	Full
Surplus price ($\chi^{\uparrow^{RF}}$)	0	$0.5\chi^{fix}$	$0.8\chi^{fix}$	χ^{fix}
Shortfall price ($\chi^{\downarrow^{RF}}$)	$2\chi^{fix}$	$1.5\chi^{fix}$	$1.2\chi^{fix}$	χ^{fix}
Delivery period ($\mathcal{H}_n$)	daily	weekly	monthly	yearly
Low-carbon hydrogen clause	No	Yes	Yes	Yes

IV. RESULTS AND DISCUSSION

A. Impact of contract structure

To assess the influence of contract flexibility and price on the project's techno-economic feasibility, we compare the NPV of the project and hydrogen delivery schedule for various flexibility configurations (A, B, C, and D) and base-load hydrogen purchase agreement (HPA) price, as illustrated in Fig. 2. From an economic perspective, Fig. 2(a) shows that the NPV increases significantly with greater contract flexibility, from 32% improvement for a baseload HPA price of €3/kg to over 400% for a price of €6/kg. Notably, for a hydrogen price of €5/kg, Configuration C, which offers a high degree of flexibility, achieves a comparable NPV to Configuration A with a hydrogen price of €6/kg. This highlights that enhanced flexibility can not only improve project feasibility, but also lower hydrogen price expectations, delivering significant benefits to industries relying heavily on hydrogen.

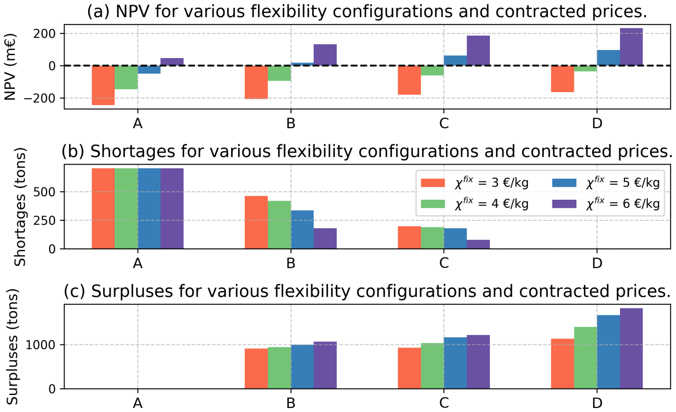

Fig. 2. (a) NPV of the project, (b) shortages, and (c) surpluses in yearly cumulative hydrogen delivery under various flexibility configurations and HPA prices considered.

From an operational perspective, Fig. 2(b)-(c) highlight that increased flexibility reduces the likelihood of unplanned hydrogen shortages while increasing the occurrence of supply surpluses. In this sense, increased flexibility ensures a more reliable supply with fewer disruptions, facilitating the integration of green hydrogen into industrial processes. However, we observe that enhanced flexibility may also lead to increased grid imports in order to capitalize on the production of additional low-carbon hydrogen during periods of low electricity prices, thereby raising the CO_2 emissions associated with hydrogen production.

B. Impact of individual flexibility parameters

While the previous analysis provided insights into the importance of contract flexibility, we now investigate the individual impact of the different flexibility parameters considered in the proposed contract structure. Fig. 3 illustrates the evolution of the project NPV under 32 configurations of the flexibility parameters, namely 4 values of the duration of delivery periods, 4 values of the balancing (shortfall and surplus) prices, and whether low-carbon hydrogen production is accepted or not. This shows that the two main drivers of the growing economic benefits of contract flexibility are the duration of the contracted delivery period and the hydrogen balancing prices. Longer contracted delivery periods directly enhance the plant's ability to mitigate renewable energy intermittence, leading to lower likelihoods of delivery shortfalls (for equal total annual contracted volumes). As a result, variations in balancing prices have the greatest impact on NPV when tight delivery schedules are enforced. In addition, longer delivery periods enhance the plant's operational flexibility and ability to capitalize on periods of low electricity prices to produce low-carbon hydrogen and create additional revenue from the sale of hydrogen. However, more penalizing balancing prices create strong incentives for the hybrid power plant to heavily prioritize RFNBO-compliant hydrogen delivery over low-carbon hydrogen delivery. As a result, we observe that the acceptance of low-carbon hydrogen, produced from electricity sourced from the grid, has a greater impact on the NPV for longer delivery periods and less penalizing balancing prices.

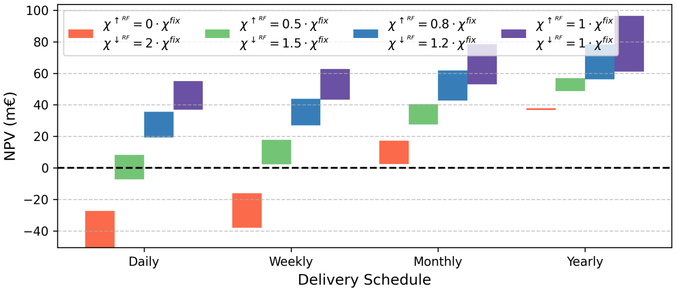

Fig. 3. NPV based on duration of delivery period (x-axis), balancing (shortfall and surplus) prices (colors) and low-carbon hydrogen clause (lower value of each bar represents acceptance of only RFNBO-compliant hydrogen, and upper value acceptance of both RFNBO-compliant and low-carbon hydrogen).

C. Sensitivity to reference case

The results presented above use 2023 as a reference year. However, these findings are strongly influenced by the renewable energy production and electricity price profiles for the reference year[1]. To better understand the sensitivity of the results to the reference profiles used, and to assess how robust and generalizable these findings are, we evaluate the plant's techno-economic feasibility using data from three reference years (2021–2023). The key characteristics of these yearly profiles are detailed in Appendix A, with 2021 showing low average spot prices, 2022 experiencing peak prices, and 2023 prices falling in between. Renewable generation capacity factors remain relatively stable across these years. Fig. 4 highlights that the relative increase in NPV and likelihoods of shortage or surplus hydrogen production across the various flexibility configurations is heavily influenced by the choice of reference year. Notably, for 2022, the full-flexibility configuration (D) shows only a minor improvement (13%) compared to the large-flexibility configuration (C), whereas this relative improvement reaches 55% for 2023 as the reference year, and 49% for 2021. This analysis helps generalizing the findings presented in this study, and emphasizes the importance of the choice of reference profiles while conducting a thorough techno-economic feasibility analysis.

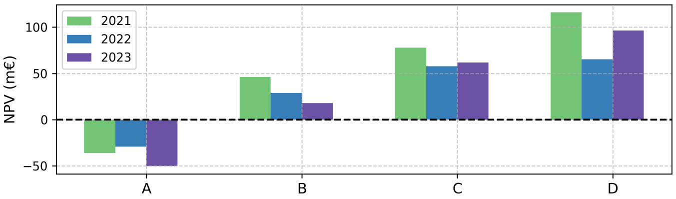

Fig. 4. NPV based on flexibility configuration and reference year.

V. Conclusion

This paper introduced a flexible hydrogen offtake contract structure, allowing the seller and offtaker to negotiate the duration of the delivery periods as well as the financial penalties and rewards for delivery surpluses and shortfalls. This work offers both qualitative and quantitative insights into the critical role of contract flexibility in de-risking investments in hybrid PtX plants. Our analysis demonstrates that the proposed flexible offtake contract structure enhances the techno-economic feasibility of hybrid PtX plants by enabling them to better manage the intermittence of co-located renewable electricity production. While flexible contracts may not guarantee a constant supply of RFNBO-compliant hydrogen, they reduce the likelihood of unplanned shortages and enable consumers to secure lower hydrogen prices. By providing a framework that enhances the techno-economic feasibility of hybrid PtX plant projects, this research contributes to removing barriers to their large-scale deployment, ultimately accelerating the decarbonization of hard-to-abate sectors.

Future research should focus on multi-year analyses and stochastic approaches, such as risk-averse modeling, to better capture long-term uncertainties. Additionally, accounting for the participation of hybrid PtX plants in energy and ancillary service markets could provide valuable insights into the influence of contract structure on the plant's ability to capitalize on these new revenue streams, further enhancing its viability.

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[1] Note that our findings are also influenced by the reference profiles and the grid renewable shares for the specific country considered, which implies that they are likely to vary for other projects.

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APPENDIX

By convention, the ramp function is denoted as $(.)^+ := \max(., 0)$, lower-case symbols represent decision variables, and upper-case or Greek symbols represent input data.

NOMENCLATURE

Acronyms and notations

CF	Cash Flow
ely	Electrolyzer
h	Hydrogen
HPA	Hydrogen Purchase Agreement
LC	Low-Carbon
LCOH	Levelized Cost of Hydrogen
NPV	Net Present Value
PPA	Power Purchase Agreement
PtX	Power-to-X
PV	Solar PV plant

RF	RFNBO-compliant
S	Storage
TSO	Transmission System Operator
W	Wind farm

Parameters

$\bar{\Gamma}$	Carbon intensity threshold for RFNBO-compliant hydrogen production [kgCO_2/kgH_2].
$\bar{H}_n$	Hydrogen mass cap for the delivery in subsets $\mathcal{H}_n$ [kg].
$\bar{P}^h$	Maximum power consumption of the electrolyzer [MW].
$\bar{P}_t^{PV}$	Solar power production forecast in time-step $t \in \mathcal{T}$ [MW].
$\bar{P}_t^{W}$	Wind power production forecast in time-step $t \in \mathcal{T}$ [MW].
$\bar{S}^h$	Maximum capacity of the hydrogen storage [kg].
$\bar{S}_{in}^h$	Maximum input mass flow of the hydrogen storage [kg/h].
$\bar{S}_{out}^h$	Maximum output mass flow of the hydrogen storage [kg/h].
$\chi^{\downarrow^{RF}}$	Hydrogen penalty price for the shortage in RFNBO compliant hydrogen volume [€/kg].
$\chi^{\uparrow^{LC}}$	Hydrogen price for the low-carbon volume delivered [€/kg].
$\chi^{\uparrow^{RF}}$	Hydrogen price for the RFNBO compliant excess volume delivered [€/kg].
χ^{fix}	Hydrogen price of the base load RFNBO volume contracted [€/kg].
η_S^h	Efficiency of the hydrogen storage [%].
$\kappa^{e \rightarrow h}$	Conversion efficiency of the electrolyzer [MWh/kg].
λ^{TSO}	TSO fixed tariff [€/MWh].
λ_t^{DA}	Day-ahead electricity price in time-step $t \in \mathcal{T}$ [€/MWh].
ρ	Discount rate of the project.
$\underline{P}^h$	Minimum power consumption of the electrolyzer [MW].
$\underline{S}^h$	Minimum capacity of the hydrogen storage [kg].
$\widehat{H}_n$	Contracted RFNBO compliant hydrogen mass to be delivered in subsets $\mathcal{H}_n$ [kg].
I_0	Investment cost for the hybrid PtX plant [€].
I_0^u	Investment cost per installed capacity of unit $u \in \{PV, W, h, S\}$ [€].
K^{su}	Cold start-up cost of the electrolyzer [€].
$O^{fix,u}$	Fixed OPEX per installed capacity of unit $u \in \{PV, W, h, S\}$ [% CAPEX].
O^{fix}	Yearly fixed OPEX for the hydrid PtX plant [€].
$O^{var,u}$	Variable OPEX per energy flow of unit $u \in \{PV, W, h, S\}$ [€/MWh] or [€/kg/h].
P_{com}^h	Power consumption of the hydrogen compressor [MWh/kg].
P_{sb}^h	Standby power consumption of the electrolyzer [MW].
$S_{ini}^{h,c}$	Initial storage level of the hydrogen classified as $c \in \{RF, LC\}$ storage [kg].
t_0	Initial time-step for the initialization.
Δ_t^{grd}	Renewable share in the grid [%] in time-step $t \in \mathcal{T}$.

Sets

$\mathcal{H}_n$	Set of time-steps in sub-periods n in the set $\mathcal{N}$ for the HPA delivery.
$\mathcal{N}$	Set of sub-periods for the HPA delivery.
$\mathcal{S}^{RF}$	Set of subsets for the horizon calculation of the carbon intensity of the hydrogen produced.
$\mathcal{T}$	Set of time-steps corresponding to the time-step resolution of the model.
$\mathcal{T}^{RF}$	Set of time-steps in the subsets of $\mathcal{S}^{RF}$.
$\mathcal{Y}$	Set of years corresponding to the lifetime of the project.

Variables

$c_y^{grd} \in \mathbb{R}^+$	Cost of power bought from the grid on the day-ahead market in year $y \in \mathcal{Y}$ [€].
$h_t^{ely,LC} \in \mathbb{R}^+$	Low-carbon hydrogen production of the electrolyzer in time-step $t \in \mathcal{T}$ [kg].
$h_t^{ely,RF} \in \mathbb{R}^+$	RFNBO-compliant hydrogen production of the electrolyzer in time-step $t \in \mathcal{T}$ [kg].
$h_t^{ely} \in \mathbb{R}^+$	Hydrogen production of the electrolyzer in time-step $t \in \mathcal{T}$ [kg].
$h_t^{in,c} \in \mathbb{R}^+$	Hydrogen classified as $c \in \{RF, LC\}$ volume in of the hydrogen storage in time-step $t \in \mathcal{T}$ [kg].
$h_t^{out,c} \in \mathbb{R}^+$	Hydrogen classified as $c \in \{RF, LC\}$ volume out of the hydrogen storage in time-step $t \in \mathcal{T}$ [kg].
$h_t^{c} \in \mathbb{R}^+$	Hydrogen classified as $c \in \{RF, LC\}$ physical flow related to the hydrogen offtake in time-step $t \in \mathcal{T}$ [kg].
$o_y^{var} \in \mathbb{R}^+$	Variable OPEX for the hydrid PtX plant in year $y \in \mathcal{Y}$ [€].
$p_t^{com} \in \mathbb{R}^+$	Power consumption of the hydrogen compressor in time-step $t \in \mathcal{T}$ [MW].
$p_t^{grd} \in \mathbb{R}^+$	Power from the grid in time-step $t \in \mathcal{T}$ [MW].
$p_t^{h} \in \mathbb{R}^+$	Power consumption of the electrolyzer in time-step $t \in \mathcal{T}$ [MW].
$p_t^{PVcur} \in \mathbb{R}^+$	Curtailment of the solar farm in time-step $t \in \mathcal{T}$ [MWh].
$p_t^{PV} \in \mathbb{R}^+$	Production of the solar farm in time-step $t \in \mathcal{T}$ [MWh].
$p_t^{Wcur} \in \mathbb{R}^+$	Curtailment of the wind farm in time-step $t \in \mathcal{T}$ [MWh].
$p_t^{W} \in \mathbb{R}^+$	Production of the wind farm in time-step $t \in \mathcal{T}$ [MWh].
$r_y^{bal} \in \mathbb{R}$	Balancing revenue of the hydrogen contract in year $y \in \mathcal{Y}$ [€].
$r_y^{fix} \in \mathbb{R}^+$	Fixed revenue of the hydrogen contract in year $y \in \mathcal{Y}$ [€].
$s_t^{h,c} \in \mathbb{R}^+$	Hydrogen classified as $c \in \{RF, LC\}$ storage level in time-step $t \in \mathcal{T}$ [kg].
$v_n^{c} \in \mathbb{R}^+$	Hydrogen classified as $c \in \{RF, LC\}$ delivered in delivery period $n \in \mathcal{N}$ [kg].
$z_t^{on}, z_t^{off}, z_t^{sb} \in \{0, 1\}$	Binary variables defining *On*, *Off*, and *Stand-by* state of the electrolyzer in time-step $t \in \mathcal{T}$.
$z_t^{su} \in \{0, 1\}$	Binary variable defining a cold startup of the electrolyzer in time-step $t \in \mathcal{T}$.

A. Parameters

This section describes the parameters of the components of the hybrid system, including technical and economic considerations. General parameters are defined in Table II and financial parameters for the cost estimation are defined in Table III. The hydrogen compressor for the storage is assumed to compress hydrogen out of the electrolyzer from 20 bar to 300 bar with a mechanical efficiency of 75% and to follow an isentropic compression.

TABLE II
PARAMETERS DEFINITION

Content	**Notation**	**Value**	**Unit**
Capacity wind farm	$\bar{P}^{PV}$	100	MW
Capacity solar farm	$\bar{P}^{W}$	100	MW
Capacity electrolyzer	$\bar{P}^{h}$	100	MW
Capacity storage	$\bar{S}^{h}$	20	tons
Efficiency storage	η^{h}_{S}	100	%
Compressor consumption	P^{h}_{comp}	1.843	kWhe/kgH_2
Conversion rate	$\kappa^{e\rightarrow h}$	52.5	MWh/kg
CO_2 threshold	Γ^{cap}	3.38	kgCO_2/kgH_2
Annual H_2 demand	$\sum_{n\in\mathcal{N}}\widehat{H}_n$	9.1	ktons
Base H_2 price	χ^{fix}	5	€/kg
Low-Carbon H_2 price	$\chi^{\uparrow,LC}$	$0.7\cdot\chi^{fix}$	€/kg
Lifetime	$\mathcal{Y}$	25	years
Discount rate	ρ	7%	-
CO_2 int. calc. horizon	$\mathcal{S}^{RF}$	hourly	-

TABLE III
FINANCIAL PARAMETERS DEFINITION

	CAPEX	**OPEX fix.**	**OPEX var.**	**Ref.**
Notation	I^{u}_{0}	$O^{fix,u}$	$O^{var,u}$	-
Unit	€/MW(or kg)	%CAPEX	€/MWh	-
Solar PV	560,000	3	-	[17]
Onshore wind	1,190,000	3	1.6	[17]
Electrolysis	2,000,000	3	-	[18]
H_2 storage	460	1	-	[19]

The hourly day-ahead electricity prices are taken from REN [20]. The hourly carbon intensity and renewable content of the Portuguese grid are taken from ElectricityMaps [21], while the renewable profiles for the co-located wind and solar profiles are taken from the open source platform Renewables.ninja [22]. The characteristics of the profiles are described in Table IV.

TABLE IV
ANNUAL AVERAGE PROFILES DESCRIPTION

	2021	**2022**	**2023**	**Unit**
Cap. factor wind	43.4%	42.9%	42.5%	-
Cap. factor solar	20.0%	19.3%	19.8%	-
Cap. factor renewable	31.7%	31.0%	31.2%	-
Spot price	46.9	202.8	100.7	€/MWh
Carbon intensity	143.5	157.1	105.6	kgCO_{2eq}/MWh
Renewable share	63%	58%	71%	-

B. Costs description

The annual cost of importing electricity from the grid, c^{grd}_{y}, is defined by the electricity imported from the grid, p^{grd}_{t}, at a day-ahead market price λ^{DA}_{t} for a considered time-step t and include TSO tariff grid λ^{TSO}, as follows:

$$c^{grd}_{y} = \sum_{t\in\mathcal{T}} p^{grd}_{t}(\lambda^{DA}_{t} + \lambda^{TSO}), \qquad \forall t\in\mathcal{T}, y\in\mathcal{Y} \tag{10}$$

The investment plant of the plant, I_0, corresponds to the sum of the CAPEX of the components of the hybrid plant and depends on the installed capacity, as follows:

$$I_0 = \sum_{u\in\{PV,W,h\}} \bar{P}^{u} I^{u}_{0} + \bar{S}^{h} I^{S}_{0} \tag{11}$$

Regarding the operating costs, we consider the fixed OPEX, O^{fix}, and the variable OPEX, o^{var}_{y}. Since the model considers the plant design as given, the fixed OPEX, i.e. depending on the installed capacities, is constant. In this paper, the fixed OPEX for the components of the plant are expressed as a percentage of the component's CAPEX. On the other hand, the variable OPEX depends on the operation of the plant. The following set of equations describes this:

$$\begin{aligned} o^{var}_{y} = \sum_{t\in\mathcal{T}} \Big[& \sum_{c\in\{RF,LC\}} O^{var,S} h^{in,c}_{t} + O^{var,h} h^{ely}_{t} \\ & + \sum_{u\in\{PV,W\}} O^{var,u} p^{u}_{t} \Big], \qquad \forall y\in\mathcal{Y} \end{aligned} \tag{12}$$

$$O^{fix} = \sum_{u\in\{PV,W,h\}} O^{fix,u} I^{u}_{0} \bar{P}^{u} + O^{fix,S} I^{S}_{0} \bar{S}^{h} \tag{13}$$

C. Electrolyzer operational states

The electrolyzer is modeled with three operational states, as described in [23], to capture its operational flexibility and minimum loading. The three distinct states considered are: *On*, where the electrolyzer operates within the range between minimum loading $\underline{P}^{h}$ and maximum capacity $\bar{P}^{h}$; *Off*, when the electrolyzer is shut down and a start-up cost K^{su} is required to resume hydrogen production; and *Stand-by*, where the electrolyzer is not producing hydrogen but consumes power P^{h}_{sb} to remain at operating temperature, allowing for a rapid scale-up to full operation. The three operational states, i.e., *On*, *Off*, and *Stand-by*, corresponds to the binary variables z_{on}, z_{off}, z_{sb}, respectively, and are constrained by the following set of equations:

$$\bar{P}^{h} z^{on}_{t} + P^{h}_{sb} z^{sb}_{t} \geq p^{h}_{t}, \qquad \forall t\in\mathcal{T} \tag{14}$$

$$p^{h}_{t} \geq \underline{P}^{h} z^{on}_{t} + P^{h}_{sb} z^{sb}_{t}, \qquad \forall t\in\mathcal{T} \tag{15}$$

$$z^{sb}_{t} + z^{on}_{t} + z^{off}_{t} = 1, \qquad \forall t\in\mathcal{T} \tag{16}$$

$$z^{su}_{t} \geq z^{on}_{t} - z^{on}_{t-1} - z^{sb}_{t-1}, \qquad \forall t\in\mathcal{T}/t_0 \tag{17}$$

$$z^{sb}_{t} + z^{off}_{t-1} \leq 1, \qquad \forall t\in\mathcal{T}/t_0 \tag{18}$$

$$z^{su}_{t_0} = 0, \tag{19}$$

The initial time-step for the initialization is characterized by t_0.

D. Hydrogen storage

The constraints related to the hydrogen storage are described below with a separation of the RFNBO-compliant and low-carbon hydrogen. The equality and inequality constraints applicable to the storage modeling are defined as following:

$$\underline{S}^h \leq s_t^{h,RF} + s_t^{h,LC} \leq \bar{S}^h, \qquad \forall t \in \mathcal{T} \tag{20}$$

$$h_t^{out,RE} + h_t^{out,LC} \leq \bar{S}^h_{out}, \qquad \forall t \in \mathcal{T} \tag{21}$$

$$h_t^{in,RE} + h_t^{in,LC} \leq \bar{S}^h_{in}, \qquad \forall t \in \mathcal{T} \tag{22}$$

$$p_t^{h_{com}} = (h_t^{in,RE} + h_t^{in,LC}) \cdot P^h_{com}, \qquad \forall t \in \mathcal{T} \tag{23}$$

The dynamic constraints related to the virtual RFNBO-compliant and low-carbon hydrogen storage, characterized by their classification c, as described in the following set of equations:

$$s_{t_0}^{h,c} = S_{ini}^{h,c} + h_{t_0}^{in,c} - h_{t_0}^{out,c}, \quad \forall c \in \{RF, LC\} \tag{24}$$

$$s_t^{h,c} = s_{t-1}^{h,c} + h_t^{in,c} - h_t^{out,c}, \quad \forall t \in \mathcal{T}/\mathcal{T}_0, \forall c \in \{RF, LC\} \tag{25}$$

E. Hydrogen Export Flows

RFNBO compliant and low-carbon hydrogen flows from the electrolyser and storage are defined as separate streams. The offtake volume for a classification c, RFNBO-compliant (RF) or low-carbon (LC); at a time step t, h_t^c, is expressed as the sum of the produced volume $h_t^{ely,c}$ and the difference between the hydrogen entering and leaving the storage characterized by $h_t^{in,c}$ and $h_t^{out,c}$, taking into account the storage efficiency η_S^h, as follows:

$$h_t^c = h_t^{ely,c} - \frac{h_t^{in,c}}{\eta_S^h} + h_t^{out,c} \cdot \eta_S^h, \quad \forall t \in \mathcal{T}, \forall c \in \{RF, LC\} \tag{26}$$

Finally, the RFNBO-compliant hydrogen volumes v_n^{RF}; low-carbon hydrogen volumes v_n^{LC}; supplied over a contracted delivery period $n \in \mathcal{N}$, are expressed as the sum of the production over all the time-steps within this period $t \in \mathcal{H}_n$, such that:

$$\sum_{t \in \mathcal{H}_n} h_t^c = v_n^c, \qquad \forall n \in \mathcal{N}, \quad \forall c \in \{RF, LC\} \tag{27}$$

F. Illustrative delivery schedule with shortages and excesses

Fig. 5 represents hydrogen delivery over n delivery periods. The RFNBO-compliant hydrogen contracted volume (blue line) is assumed constant in this example and priced at χ^{fix}. A maximum delivery volume is set by the upper-bound $\bar{H}$ (red line). The RFNBO-compliant volume (green) is supplemented by additional low-carbon hydrogen (grey) from grid imports. The RFNBO compliant surplus (above the blue line) is priced at $\chi^{\uparrow^{RF}}$, while the low-carbon is priced at $\chi^{\uparrow^{LC}}$. In the situation where the delivered RFNBO-compliant volume is less than the contracted volume over the considered delivery period, a shortfall volume (orange) is to be repaid at a price of $\chi^{\downarrow^{RF}}$.

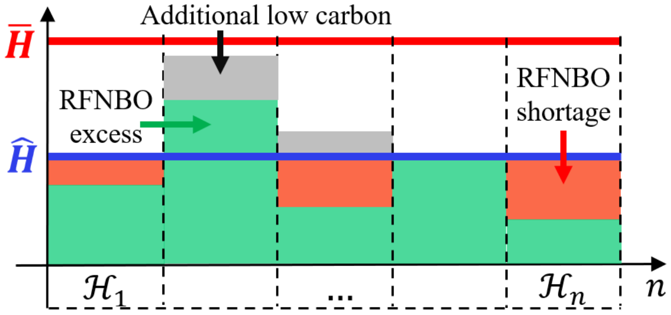

Fig. 5. Example of hydrogen deliveries for n delivery periods

G. Hydrogen delivery shortages and surpluses in various flexibility configuration and reference year

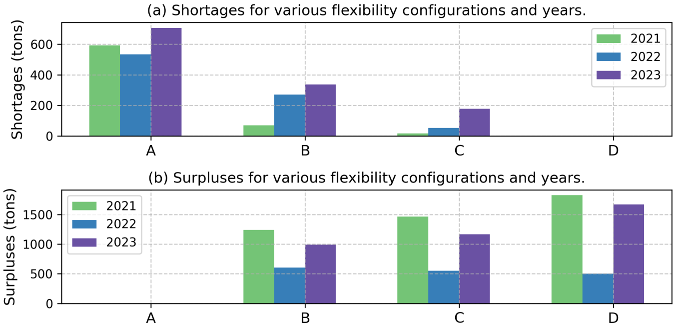

Fig. 6. Accumulated hydrogen delivery (a) shortages and (b) surpluses based on flexibility configuration and reference year.