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Implications of the Inflation Reduction Act on Deployment of Low-Carbon Ammonia Technologies

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Abstract

Building on the stochastic economic analysis of the plant-level ammonia production (AP) model, this study comprehensively considers key low-carbon AP pathways - steam methane reforming with carbon capture and storage (CCS), biomass gasification (BH2S), and electrolysis (AEC) - under multiple policy frameworks – subsidies, carbon pricing, renewable hydrogen rules. CCS and BH2S demonstrate strong economic potential under the Inflation Reduction Act due to cost-effectiveness and limited public support requirements. In contrast, AEC faces economic challenges due to high costs and low efficiency. To efficiently decarbonize AP, policymakers and academia should prioritize (i) adapting Haber-Bosch (HB) processes for variable bioenergy quality, (ii) ensuring safe CO2 transport and storage while mitigating CCS value chain risks, (iii) supporting R&D to reduce costs and enhance efficiency in flexible HB, renewable energy, and storage technologies, and (iv) establishing a technologically neutral policy framework that considers dynamic cost reductions and interactions between policy instruments and technologies.

Keywords: Ammonia; Inflation Reduction Act; US Energy Policy; Energy; Carbon Tax; Carbon Cost; Carbon Capture; Biomass Gasification; Alkaline Electrolysis; Haber-Bosch; Techno-Economic Analysis; Social Cost of Carbon; Hydrogen Production Tax Credits.

JEL classification: Q48; H25; Q42; Q54; Q55; G11

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List of abbreviations

Abbreviation	*Meaning*
CI	Carbon intensity
CAC	Carbon abatement cost
AP	Ammonia production
SMR	Steam-methane reforming
CCS	Carbon capture system
BH2S	Biomass gasification
AEC	Alkaline electrolysis
TC	Tax credit
PTC	Production tax credit
ITC	Investment tax credit
CBAM	Carbon Border Adjustment Mechanism
IRA	Inflation Reduction Act

1. Introduction

As the global energy system gradually undergoes a challenging transition to meet future energy demand growth and climate change mitigation goals in the presence of multiple sources of uncertainty (market, regulatory, and policy) and technology risks, ammonia represents a versatile energy vector – it is a feedstock (e.g., agricultural, textiles, and pharmaceutical sectors), a potential low-carbon fuel (e.g., for electricity generation and maritime transport) as well as reliable energy storage, transport, and delivery option for low-carbon hydrogen (The Royal Society, 2020).

Unlike other emerging low-carbon fuels, such as hydrogen, ammonia is a globally traded commodity with a reasonably well-developed infrastructure and market (IRENA & AEA, 2022). However, accounting for 3% of global CO_2 emissions and having a carbon intensity of 2.4 MTs of CO2 per MT of NH3 – two times higher than steel and four times higher than cement – decarbonization of ammonia production (AP) represents a hurdle to achieving net zero emissions by 2050 (EIA, 2023; El Kadi et al., 2020; IEA, 2021; Smith et al., 2020; Tullo, 2021). According to the US Energy Information Administration (EIA), 98% of global AP originates from fossil fuels – approximately 72% from natural gas and 22% from coal (EIA, 2023). The currently commercially-proven AP pathway uses steam methane reforming (SMR) and water gas shift (WGS) reactions to produce a cheap, high-emissions hydrogen source for the ammonia production step – the Haber-Bosch (HB) process (Salmon & Bañares-Alcántara, 2021).

Since hydrogen and ammonia production modes are technologically symbiotic, their multi-faceted value chains generate possibilities for tighter "sector-coupling" to decarbonize hard-to-abate sectors cost-efficiently. Considering the relatively high cost of batteries for energy storage and transportation, ammonia is gaining traction as the next long-term energy storage solution for abating the inherent intermittency of renewable energy sources (RES) (Cole & Frazier, 2019; MacFarlane et al., 2020). At a scale of 180 Mt of ammonia, the infrastructure[1] behind high-carbon ammonia can be leveraged to transition to net-zero pathways by 2050 (IEA, 2021). Furthermore, ammonia is a genuinely low-carbon alternative to hydrogen owing to its attractive economics for storage and transportation because H_2 must be stored at -270C or 345 bar, while NH3 can be stored at -33C or 10 bar (MacFarlane et al., 2020).

IRENA estimates in a 2050 net-zero world that AP will reach 688 MT per year, of which 566 Mt will come from renewable ammonia (IRENA & AEA, 2022). According to McFarlane et al. (2020), the growth and transition of the ammonia industry will come in three stages. The first stage will be characterized by efforts to retrofit/integrate carbon capture systems (CCS) into existing AP SMR plants. By approximately 2030, McFarlane et al. and IRENA estimate the energy penalty incurred by CCS will bring in other, more energy-efficient pathways that utilize renewable hydrogen sources (i.e., biomass gasification) – this represents the second stage of the above transition path. Finally, the third stage will consist of green-energy-powered electrolysis pathways for AP (del Pozo & Cloete, 2022; IRENA & AEA, 2022; Salmon & Bañares-Alcántara, 2021).

Despite the apparent advantages, the high costs associated with these new technologies compared to the incumbent AP SMR method, not fully developed and adequately demonstrated at the commercial scale, and lack of policy support have deterred investment and their mass deployment. In 2021, only 0.02Mt of renewable ammonia was produced (IRENA & AEA, 2022). Dakota Gasification Co. is one of a few examples of implementing CCS systems at the industrial level (EIA, 2021; IRENA & AEA, 2022). CF Industries is building a 20 kt per year electrolysis AP facility in partnership with Thyssenkrupp Industrial Solutions in Donaldson, Louisiana, and is expected to begin operation this year. Other industry leaders, such as Casale, Haldor Topsoe, KBR, Nutrien, and Yara, have announced that low-carbon ammonia features

[1] Unlike hydrogen, the pipeline and shipping technology for transportation of ammonia is mature and has a market size upwards of $70 billion (MacFarlane et al., 2020)

prominently on their company roadmap (IRENA & AEA, 2022). By 2025, new AP projects are expected to be dominated mainly by low-carbon processes (IRENA & AEA, 2022).

However, any viable realization of a resilient low-carbon energy system where low-carbon ammonia, amongst other fuels, assumes a key role currently hinges on multiple technical and socio-economic constraints such as significant capital deployment requirements, technology scale-up, infrastructure adaptation challenges, market structure characteristics as well as regulatory and policy uncertainty. According to the IEA and IRENA, governments must design and implement appropriate policies that enable the creation of markets for near-zero-emissions products (IEA, 2021; IRENA & AEA, 2022). In the US, the Inflation Reduction Act (IRA) is a prime instantiation of the commitment to creating such a market. The IRA currently contains subsidies providing unprecedented tax credits for carbon capture, low-carbon hydrogen production, and energy generation through tax credits, grants, loans, and tax rebates (IRA, 2022). The policy support for low-carbon hydrogen production within the AP process may offer valuable incentives to help turn the tide of low-carbon AP (LCAP) investment in the US.

While continued policy support is expected in the future, there are inherent risks to the deployment of LCAP technologies under the IRA that policymakers should be aware of – namely, increased reliance on grid electricity emissions and prices as all LCAP technologies are more energy intensive than AP SMR (IEAGHG, 2017; Lewis et al., 2022; Tock et al., 2013). The IEA estimates that 60% of ammonia emission reductions will originate from technologies still at the demonstration stage (IEA, 2021) – the success prospects of these low-carbon technologies may be, therefore, reliant on temporal intra- and post-IRA effects on the grid's energy transition pace and green technology improvements and costs reductions (i.e., wind, solar, batteries, and electrolysis). This dependence, combined with large AP plant lifetimes of approximately 40 years, leaves the potential LCAP investment at substantial risk of loss.

This paper looks at the potential economic impacts of IRA on investments in LCAP technologies, explicitly considering key sources of uncertainties that may affect their deployment at scale. These uncertainties are related to technology costs, market risks, environmental performance, and, by extension, the applicability of the IRA financial support for these emerging technologies. We developed a stochastic Discounted Cash Flow (DCF) model for the economic impact assessment of the IRA provisions for low-carbon technologies. We applied this model to four AP technologies summarized in Table 1. Furthermore, we investigate the economic implications (both private and public) of leveraging the EU's Carbon Border Adjustment Mechanism (CBAM) and varying the rules for matching renewable electricity and hydrogen production.

In the traditional static DCF models, investment decisions are made at the beginning based on deterministic estimates of future cash flows in the absence of any uncertainties (Chyong et al., 2012). Thus, the DCF-based deterministic economic valuation framework does not offer a straightforward way to incorporate uncertainties leading to "flaw of averages" (Savage et al., 2010), given the highly complex and non-linear value chain inherent in low-carbon energy vectors, such as ammonia. The main objective, therefore, is to use our detailed plant-level stochastic economic model to explore the economics of conventional SMR, CCS, BH2S, and AEC AP investments under the IRA. The rest of this paper is organized as follows: a brief overview of the key AP technologies is provided in §2. §3 describes our research methods, followed by the main results in §4. Finally, a discussion of policy implications and conclusions is offered in §5.

Table 1 AP considered and their policy eligibility.

Label	Technology	Feedstock[a]	IRA Credit Qualification

AP SMR	Conventional Steam Methane Reforming (SMR)	Natural gas, air	None
AP SMR CCS	SMR + Carbon Capture System (CCS)	Natural gas, air	Max[45V, 45Q] and Max[45Y, 48E]
AP BH2S	Indirect Biomass Gasification + SMR	Biomass, air	45V and Max[45Y, 48E]
AP AEC	Alkaline Electrolysis Cell	Water, air	45V and Max[45Y, 48E]

[a] To produce NH3, a nitrogen and hydrogen source is required. Air is fed to an air separation unit (ASU) for all cases to obtain high-throughput, high-purity N2 gas.

2. Conventional and low-carbon ammonia production – technical overview

This section briefly reviews the four AP technologies this report considers (Figure 1). We start with the carbon-intensive, conventional AP SMR. Then, we describe AP SMR with Carbon Capture and Storage (AP CCS), followed by AP SMR with carbon-neutral biomass, as feedstock (AP BH2S). The last low-carbon technology pathway we considered for the AP is via Alkaline Electrolysis (AP AEC). Additionally, we include a comparison of each AP technology's technical advantages and disadvantages. A comprehensive technical literature review can be found in the SI F.

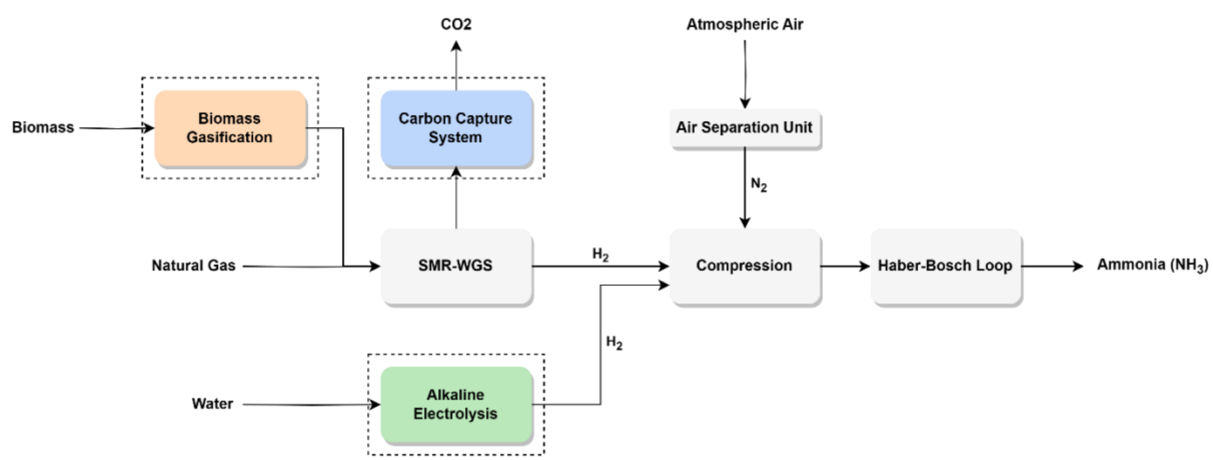

Figure 1 AP pathways considered in this report.

2.1. AP through Steam Methane Reforming (AP SMR)

The common denominator across all technologies is the notable Haber-Bosch (HB) process – a chemical process by which pure sources of hydrogen (H_2) and nitrogen (N_2) gases combine to form ammonia (NH_3). The source of N_2 is separated from the air with an air separation unit (ASU), as air is 78% N_2 by volume. For H_2, natural gas (NG) is the most prominent source (78% of global AP) – although coal is also common (22%) (EIA, 2021). NG is chemically treated to obtain pure H_2 for the HB process selectively. Specifically, the chemical treatment for hydrogen production has three major steps (Amhamed et al., 2022; Appl, 1999; IRENA & AEA, 2022; MacFarlane et al., 2020):

1. NG is cleaned of impurities such as sulfur (Kim et al., 2021).
2. The NG is mixed with steam and reacted in several heated vessels – the first reaction is called steam-methane reforming (SMR), and the second is the water-gas shift (WGS) reaction. The resulting chemicals from these reactions are methane, CO_2, and H_2.
3. H_2 is separated from CO_2 and methane in a pressure-swing absorption unit (PSA). The pure H_2 product is sent to the HB process. The remaining methane and CO_2 heat the SMR vessel through combustion. Finally, the combusted gas is emitted into the environment through the plant's stack.

The H_2 from the HP process and the N_2 from the ASU must be compressed because the HB process requires extreme pressures and temperatures. The compression of H_2 and N_2 is the most energy-intensive step in AP. The source of energy for compression varies across technologies (see §2.5)

The typical AP SMR plant produces 500 to 3000 metric MTs per day (TPD) of NH_3 (Amhamed et al., 2022; IEA, 2021). The IEA reports that the break-even AP SMR ammonia price ranges from approximately \$300 to \$600 per ton of NH3, whereas the market price is between \$200 and \$750 in 2021 (IEA, 2021). Natural gas price constitutes 30% of the levelized cost of ammonia (LCOA) as it is needed for hydrogen production and heating (Appl, 1999; Maxwell, 2012; Zhang et al., 2020). Therefore, a strong correlation between natural gas and ammonia markets exists. The remaining cost is attributed primarily to capital expenditure (CAPEX) and the rest to operational expenditure (OPEX) (Appl, 1999; Maxwell, 2012).

2.2. AP SMR with a Carbon Capture System (AP CCS)

The state-of-the-art CCS technologies are amine-based carbon sequestration units operated commercially for direct air or point-source capture[2]. This CCS technology operates by mixing CO_2-rich gases with water and amine solution to dissolve the CO_2 in the solvent. The CO_2-rich solvent can be stripped of the CO_2 by heating – effectively regenerating the solvent and obtaining pure CO_2 gas for transportation and storage. CCS systems can capture up to 95% of the CO_2 within the AP plant at an additional electric energy penalty cost relative to AP SMR. A report by the DOE comparing hydrogen production via SMR with and without CCS found that H_2 SMR required 0.65 kWh/Kg H_2 of electricity, while H_2 SMR with CCS required 2.04 kWh/Kg H_2 H_2 (Lewis et al., 2022).

2.3. AP SMR with a Biomass-derived feedstock (AP BH2S)

The natural gas feedstock of AP SMR can be substituted with biomass. Hydrogen production with a biomass feedstock utilizes the organic compounds in the biomass to generate small gaseous molecules (i.e., CH_4, C_2H_4, CO, CO_2, H_2, N_2, etc.) through a process known as gasification. These molecules are further processed into H_2 and CO_2 through the conventional SMR-WGS steps (Arora et al., 2016, 2017; Tock et al., 2013; Tunå et al., 2014). According to Spath et al., the organic molecules are converted to small molecules in a separate tar reformer before the SMR to pre-treat the syngas for sulfur contaminants and avoid char formation – although the goal design would be to perform tar reforming and SMR in the same vessel (Spath et al., 2005).

Biomass feedstocks are effectively net-zero, as the carbon emitted by biomass comes from the atmospheric CO_2 fixated into plants through photosynthesis. However, the electric

[2] In this report, CCS refers to Methyl diethanolamine (MDA) solvent-based carbon capture units.

energy requirements to process the biomass into usable NG-like synthesis gas are in the ballpark of AP CCS (Lewis et al., 2022; Spath et al., 2005). Hence, significant and possibly IRA-disqualifying indirect emissions of AP BH2S may be a fault of a carbon-intensive electric source (i.e., the electric grid) (EIA, 2023).

2.4. AP via Alkaline Electrolysis (AP AEC)

The most abundant source of hydrogen is water. Water contains zero carbon and can be electrolyzed to produce pure hydrogen and oxygen gas. The advantage of electrolysis is that it is modular and suitable for decentralized systems (Böhm et al., 2020; Sousa et al., 2022). The current competing technologies are alkaline water electrolysis (AEC), proton exchange membrane electrolysis (PEM), and solid oxide electrolysis (SOE) (Böhm et al., 2020; dos Santos et al., 2017; Proost, 2017; Schmidt et al., 2017).

AEC is the most competitive technology as it has a high lifetime (60,000-90,000 hours (h)) and a low cost (1300-500 $/kW) when compared to PEM (20,000-90,000h and 2000-800 $/kW) (Schmidt et al., 2017). SOE stacks have the highest cost among all technologies (5000-1500 $/kW) and the shortest lifetime (<20,000h) as they are still at the laboratory stage (Schmidt et al., 2017). Nevertheless, SOE stacks are expected to experience the most significant cost reductions from deployment and R&D (Lee et al., 2021; Schmidt et al., 2017). AP AEC forms a small part of AP in general (<0.02 Mt in 2021) (Böhm et al., 2020; IRENA & AEA, 2022). AEC pathways and other electrolysis technologies expect cost reductions of 0-24% from R&D and 17-30% from production scale-up (Schmidt et al., 2017).

While electrolytic pathways mitigate emissions by ensuring a zero-carbon feedstock, the additional electric energy demand can be higher (Singh et al., 2019). Gomez and colleagues identified that H2 electrolysis required 50-60 kWh/kg H_2 versus 0.65 kWh/kg H_2 for SMR (Gomez et al., 2020; Lewis et al., 2022). The additional electricity usage renders electrolytic hydrogen production to be non-zero because of the indirect emissions of the grid and construction materials. Simons and Bauer estimate solar-powered electrolysis at 3 kg CO_2 eq/kg H_2 and wind at 2 kg CO_2 eq/kg H_2 due to the indirect emissions of the construction materials for wind and solar alone (Simons et al., 2011).

2.5. Economic and environmental comparison of AP across the literature.

The most often used and preferred method in the literature to compare economic performance of low carbon hydrogen and ammonia is the levelized cost approach (LCOH and LCOA) (Arora et al., 2016, 2017; Campion et al., 2022; del Pozo & Cloete, 2022; Gomez et al., 2020; Guerra et al., 2020; Lee et al., 2021; Lewis et al., 2022; Osman et al., 2020; K. H. R. Rouwenhorst et al., 2019; Sánchez et al., 2019; Sousa et al., 2022; Tock et al., 2013; G. Wang et al., 2020a; Zhang et al., 2020). The LCOA, while pertinent in numerous instances, is primarily focused on the production cost side of the equation, potentially overlooking the IRA's significant dynamics, which influence the revenue side.

This revenue-side influence, particularly concerning income taxes, is outside the scope of the LCOA, necessitating assumptions that could potentially overstate outcomes[3]. For instance, Jenkins et al. (2023) implicitly assumed all tax credits equal $1 US dollar by awarding full credit value to their levelized cost analysis. This approach may lead to overestimations,

[3] The LCOA's effective income tax rate skews towards 0% as the revenues generated are only sufficient to offset the costs. With no income tax to abate, this framework's dependence on selling tax credits invites the risk of incorporating potentially oversimplifying assumptions. This issue becomes particularly notable under conditions of an unpredictable tax credit market.

particularly regarding policy support for low-profit, riskier, low-carbon technologies that heavily rely on a tax credit market. Consequently, this study adopts the NPV approach, offering a more comprehensive and nuanced perspective better suited to capturing the real-world effects of income tax credit-based policies like the IRA.

Regarding the electric energy intensity of AP, compressing the gas out of the HP and ASU systems before the HB loop is known to be a highly energy-intensive step. Hence, using surplus energy from other parts of the process is a critical step that may sometimes drive AP SMR to generate electricity (IEAGHG, 2017). This energy integration step is essential in determining the relative OPEX between AP SMR and low-carbon technologies. Some technologies lack surplus energy to power the compression and need to purchase energy from the grid.

In general, AP SMR may have surplus energy to power the entire compression load, and hence, it uses the least amount of grid electricity (IEAGHG, 2017; Lewis et al., 2022). AP CCS does not have surplus energy and uses grid electricity (IEAGHG, 2017; Lewis et al., 2022). AP BH2S does have surplus energy for one compression process but has two in total – hence using around the same amount of grid electricity as AP CCS (Spath et al., 2005). Finally, AP AEC needs an order of magnitude larger amount of electricity for hydrogen production. It does not have surplus energy for compression – making it the most electrically energy-intensive process in the portfolio (Gomez et al., 2020). Regarding total energy efficiency, AP AEC is the least efficient, followed by BH2S and CCS. AP SMR is the most energy-efficient pathway (del Pozo & Cloete, 2022; Smith et al., 2020; Spath et al., 2005; Tock et al., 2013).

In terms of economic cost assessment, large-scale AP SMR plants, with capacities above 2000 TPD of ammonia, can have capital expenditure (CAPEX) ranging from $500M ($250k/TPD NH3) to $1800M ($900k/TPD NH3) and operating expenditure (OPEX) ranging from $180 to $500 per ton of NH3 (IEA, 2021; Maxwell, 2012; Pfromm, 2017). For AP CCS at an 88.2% capture rate, the CAPEX is estimated to be between $298k/TPD NH3 and $275k/TPD NH3, with an OPEX of €280/Ton NH3 (del Pozo & Cloete, 2022). On the other hand, AP BH2S costs have been studied at scales of 73 to 1187 TPD NH3. Arora et al. (2017) provided a detailed process model for biomass gasification at 73.5 TPD NH3. They noted that the CAPEX and OPEX of biomass gasification are between $170k to $175k/TPD NH3 and $705 to $722/ton NH3, respectively.

Although specific cost data for AP AEC was not easily found in the literature, it is likely to have similar or higher costs than AP CCS and AP BH2S, depending on variable factors such as electricity costs (OPEX-related) and electrode stack costs (CAPEX-related), which are highly uncertain variables (Sousa et al., 2022). AP AEC is the pathway expected to reduce cost due to modularity (Schmidt et al., 2017). AP CCS is expected to remain at a similar cost level –hence only seen as a transitory technology for decarbonization (MacFarlane et al., 2020). AP BH2S, on the other hand, presents significant uncertainties regarding its cost and feedstock availability (Sánchez et al., 2019; Tock et al., 2013; Tunå et al., 2014).

On the environmental front, life cycle assessments (LCA) of AP SMR produce variable results involving the emissions intensity of ammonia production. The cradle-to-gate equivalent CO_2 emissions of AP SMR varied by 10 to 15% from the average across studies (Bicer et al., 2016; Bicer & Dincer, 2017; Liu et al., 2020). For example, Bicer and colleagues measured the emissions intensity for AP SMR to be 1.6 kg of equivalent CO2 emissions (kgCO2e) per kg of NH3 with a plant-wide scope, while ARPA-E reported a value of 2.55 kgCO2e/kgNH3 for a cradle-to-gate analysis using the GREET model (Bicer et al., 2016; Bicer & Dincer, 2017). Liu and colleagues reported emissions intensities of around 1.8 kgCO2e/kgNH3 for a cradle-to-gate scope (Liu et al., 2020). Young and colleagues found that CCS reduced cradle-to-gate CO2e emissions by 69% (Young et al., 2019).

The DOE report on hydrogen production via SMR with CCS found similar results at a 61% reduction in cradle-to-gate CO2e intensity (Lewis et al., 2022). The average CO2e intensity of AP SMR across four studies is approximately 11.7 kgCO2e/kgH2 (1.99 kgCO2e/kgNH3[4]) (Bicer et al., 2016; Bicer & Dincer, 2017; Liu et al., 2020) – Please note that reductions by 61-69% qualify AP SMR with CCS for significant 45Q carbon sequestration credits under IRA (Bauer et al., 2022; Lewis et al., 2022).

AP through BH2S has been considered a viable alternative to ammonia production as it is a zero-carbon fuel (Arora et al., 2016, 2017; Gilbert et al., 2014). Gilbert and colleagues show that biomass reduces cradle-to-gate emissions to 0.7 kg CO2e/kg NH3 (3.95 kg CO2e/kg H2) from a 1.9 kg CO2e/kg NH3 (10.7 kg CO2e/kg H2) natural gas AP SMR baseline (Gilbert et al., 2014). The environmental performance of AP w/ BH2S has also been shown to decrease with increasing scale at varying proportions depending on the type of biomass. Arora et al. (2017) display results indicating the inverse relationship between decreasing life-cycle emissions and scale-up cost reductions (Arora et al., 2017).

While AP AEC pathways mitigate emissions by ensuring a zero-carbon feedstock, the additional indirect electric energy emissions can be higher. The estimated potential emissions intensity of AP AEC can range between 4.4-2.2 kg CO2e/kgH2. Simons and Bauer estimate solar-powered electrolysis at 3 kg CO2e/kgH2 and wind at 2 kgCO2e/kgH2 due to the indirect emissions of the construction materials for wind and solar (Simons et al., 2011). Borole and Greig estimated wind-powered electrolysis at 0.97 kgCO2e/kgH2, and Valente et al. estimated 0.3 kgCO2e/kgH2 (Borole & Greig, 2019; Valente et al., 2020). Liu and colleagues estimated the emissions intensity of N2 production and the Haber-Bosch to be 0.3 kgCO2e/kgH2 and 0.9 kg CO2e/kgH2, respectively (Liu et al., 2020). By adding Liu et al.'s estimates to the results, the estimated potential emissions intensity of AP AEC can range between 4.4-2.2 kg CO2 eq/kg H2.

In essence, AP CCS and AP BH2S are effective strategies for significantly reducing the carbon emissions associated with AP SMR. Despite this, AP CCS is inherently limited by a capture rate that falls short of 100%, leading to unavoidable residual emissions. In contrast, AP BH2S holds the potential for near-net-zero emissions at the risk of limited feedstock supplies and quality. Alternatively, AP AEC can attain net-zero emissions, provided that the emissions linked to the production of materials are disregarded, especially in scenarios where the power generation is green.

3. Methods

Figure 2 illustrates our research methodology. This section first gives an outline of our process economic plant-level model. Then, it describes the stochastic DCF model and gives an overview of policy modeling, scenarios considered in this analysis, and key assumptions. Lastly, the section describes model validation, the robustness of results and their convergence. All related chemical processes, techno-economic parameters, and assumptions are listed and described in the accompanying SI.

[4] Hydrogen is approximately 17% of NH3 by mass. Hence, carbon intensity values on a per-NH3 or H2 unit are interchangeable. Regardless of basis units, ammonia processes will be more carbon intensive as there is more processing than hydrogen production.

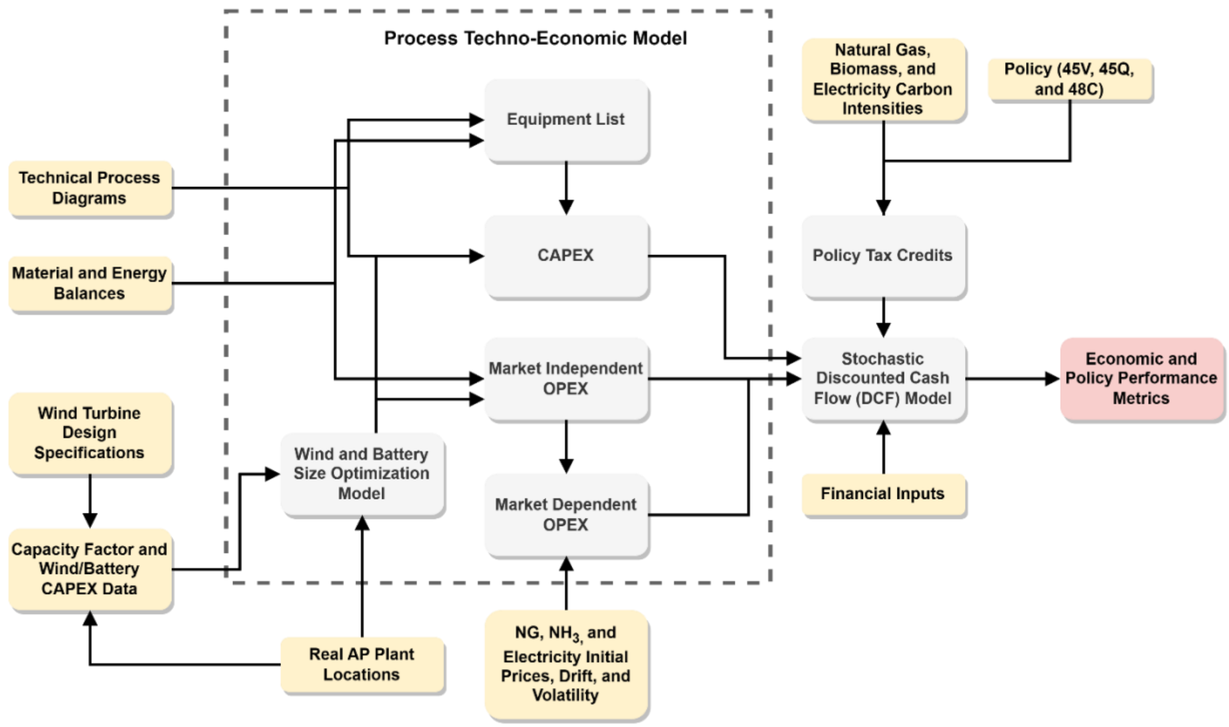

Figure 2 Simplified representation of the research methodology

3.1. Baseline Process Economic Model

To address the impact of the IRA on the low-carbon pathways, we first developed a fixed capital investment and operational expenditure AP plant model, utilizing the techno-economic framework proposed by Peters and Timmerhaus (Peters et al., 2003) – details can be found the SI §A. Figure 2 below illustrates a simple description of the model. In what follows, we present our stochastic DCF model. A complete list of inputs of the model can be found in SI C. We first define the basic deterministic DCF and then outline key inputs that we consider in our stochastic DCF model. Lastly, we summarize the policy and scenarios we model and discuss model validation, robustness of modelling results and its convergence.

3.1.1. Baseline Discounted Cash Flow (DCF) Model

The economic performance of each technology pathway was assessed using a Net Present Value (NPV) per lifetime ammonia produced metric. NPV is the sum of the present value of all cash flows at each period (monthly basis) over the lifetime amount of ammonia production, M_{NH3} (eq. 1a).

$$\boldsymbol{NPV_j} = \frac{\mathbf{1}}{\boldsymbol{M_{NH3}}} \sum_{\boldsymbol{T=0}}^{\boldsymbol{L}} \frac{\boldsymbol{CF_{j(T)}}}{[(\mathbf{1}+\boldsymbol{i})(\mathbf{1}+\boldsymbol{d})]^{\boldsymbol{T}}} \tag{1a}$$

$$\boldsymbol{d} = \boldsymbol{e} * \boldsymbol{R_e} + [\mathbf{1}-\boldsymbol{e}] * \boldsymbol{R_d} * [\mathbf{1} - (\boldsymbol{\varphi_{state}} + \boldsymbol{\varphi_{federal}})] \tag{1b}$$

where $\boldsymbol{M_{NH3}}$ is the lifetime amount of ammonia produced, $\boldsymbol{CF(T)}$ is the cash flow at time $\boldsymbol{T}$, and $\boldsymbol{d}$ and $\boldsymbol{i}$ are the real discount and inflation rates, respectively. The cash flow equals the sum of seven cost components (eq. 2); $\boldsymbol{d}$ – discount rate, was calculated as the weighted average cost of capital (WACC) (eq. 1b); $\boldsymbol{e}$ is the equity, $\boldsymbol{R_e}$ is the cost of equity, $\boldsymbol{R_d}$ is the cost of debt, and $\boldsymbol{\varphi_{state}} + \boldsymbol{\varphi_{federal}}$ are the state and federal income taxes, respectively.

$$\begin{gathered} \boldsymbol{CF_{j(T)} = FCI_j(T) + Land_j(T) + WC_j(T) + PMT_j(T)} \\ \boldsymbol{+Sales_j(T) + OPEX_j(T) + Tax_j(T) + Credits_{CE_j}(T)} \end{gathered} \tag{2}$$

where $\boldsymbol{FCI_j(T)}$ is the fixed capital investment – invested over the first three years and derived in SI 2; $\boldsymbol{Land_j(T)}$ and $\boldsymbol{WC_j(T)}$ are the costs of purchasing land and injecting working capital to begin operation; $PMT_j(T)$ represents the payment of borrowed capital for the construction of the plant; $\boldsymbol{Sales_j(T)}$ and $\boldsymbol{OPEX_j(T)}$ represent revenue from selling ammonia to the market and the plant's cost, respectively. $\boldsymbol{Tax_j(T)}$ is the income tax and $\boldsymbol{Credits_{CE_j}(T)}$ represents the cash-equivalent IRA tax credits. The IRA credits are described in the policy section below.

3.1.2. Stochastic Treatment of the DCF Model

As mentioned earlier, traditional valuation and economic performance methods for low-carbon technology options based on DCF models do not offer an explicit way to incorporate and quantify inherently uncertain conditions that could have asymmetric impacts on economic performance due to model nonlinearities and constraints. Therefore, evaluating economic performance at average conditions does not necessarily represent average economic performance, a result known as the "flaw of averages" in probability theory (de Neufville & Scholtes, 2011). As a result, the latter could lead to erroneous investment decisions and comparative assessments of investment projects.

These limitations can be effectively overcome by the integration of Monte Carlo simulation techniques that can offer probabilistically unbiased estimates of the expected NPV (or any other performance metric) as well as additional valuable statistical measures (standard deviation, Value at Risk/Value at Opportunity) inferred directly from a detailed characterization of its probability distribution profile. Furthermore, a Monte Carlo-based assessment framework can simultaneously accommodate multiple sources of uncertainty, unlike traditional sensitivity analysis, where varying a single unknown model input while keeping the rest at nominal/baseline values is the only way to assess the impact on the project's performance profile.

Our research methodology is designed to quantify variables' uncertainties in the following categories: market parameters (NG, NH_3, and electricity prices), policy criteria (48E credits), and each technology's lifecycle CO_2 intensities (CI). There are also financial inputs, including equity, cost-of-debt, return on equity, loan terms, depreciation, and income taxes – which we keep constant. Market parameters are used to simulate NG, NH_3, and electricity across time using general Brownian motion.

Lastly, CIs can be highly variable due to uncertain value chain emissions. We divide the CI value into the SMR emissions, NG upstream lifecycle emissions, biomass upstream emissions, and grid electricity lifecycle emissions. The SMR CI is governed by the mass and energy balances of the AP plant and originates from Lewis et al. (2022). On the other hand, NG upstream and grid electricity lifecycle emissions are uncertain due to value chain emissions and come from Nicholson & Heath (2021)[5]. Biomass emissions were obtained from a probabilistic

[5] Nicholson & Heath provide values for the CI of various generation technologies. We back-calculated the CI of upstream natural gas by obtaining the upstream CI of NGCC plants on a per $kWh_{electric}$ basis and converting it back to a $kWh_{thermal\ of\ NG}$ basis with the NGCC plant efficiency.

LCA study on dry wood chips of varying qualities (Quinn et al., 2020)[6]. Depending on the supply chain and LCA scope, NG can have varying CIs (Clark et al., 2012). The grid electricity also has uncertain CIs for the same reasons and varies depending on the grid energy composition (EIA, 2023; Nicholson & Heath, 2021). For example, a grid composed of wind and solar electricity may be net-zero, while a grid composed of coal plants would incur severe emissions penalties.

Our analysis neglects the lifecycle emissions of water and construction materials. Water has a negligible carbon intensity, and construction materials are difficult to calculate without a detailed account of plant inventory (Lewis et al., 2022). For a comprehensive description of the emissions-related input variables, please see §A-E.

3.2. Policy modeling, scenarios, and key assumptions

The AP technologies that we consider in this paper will be eligible for IRA programs 45V, 45Q, 45Y, and 48E, which consider tax credits dependent on material production (production tax credits, PTC, and CO_2 sequestration credits, CSC) as well as CAPEX-dependent tax credits (investment tax credit, ITC). Table 2 describes these policy programs.

Table 2 IRA programs considered for this analysis.

<table>
<tr><th>Policy Program</th><th>Description</th><th colspan="2">Benefits</th></tr>
<tr><td rowspan="5">New Clean Hydrogen Production Tax Credit (45V)</td><td rowspan="5">An intensive 10-year tax credit for clean hydrogen production of varying magnitude based on a Well-to-Gate Life-cycle Emissions intensity measured in $\frac{Kg\ CO_2eq}{Kg\ H_2}$.</td><td>Emissions Intensity $\frac{Kg\ CO_2eq}{Kg\ H_2}$</td><td>PTC $[\frac{\$}{Kg\ H_2}]$</td></tr>
<tr><td>0-0.45</td><td>3.00</td></tr>
<tr><td>0.45-1.5</td><td>1.00</td></tr>
<tr><td>1.5-2.5</td><td>0.75</td></tr>
<tr><td>2.5-4.0</td><td>0.60</td></tr>
<tr><td>Carbon Capture and Sequestration Tax Credit (45Q)</td><td>Imposes an intensive 12-year carbon capture tax credit on carbon capture facilities.</td><td colspan="2">The tax credit is $85/MT CO_2. To be eligible, the plant must emit more than 12,500 metric tons of CO_2 per year at the baseline.</td></tr>
<tr><td>New Clean Electricity Investment Tax Credit (48E)</td><td>Provides an investment tax credit for wind farm and battery storage projects. [a]</td><td colspan="2">30% of the CAPEX of the wind and battery system is granted as tax credits and expires at the end of 2032.</td></tr>
<tr><td>New Clean Electricity Production Tax Credit (45Y)</td><td>An intensive tax credit aimed at rewarding low-carbon electricity generation.</td><td colspan="2">1.5 cents/kWh for wind and solar projects started before 2025. PTCs expire in 2033 or when 75% emissions reductions are achieved.</td></tr>
</table>

[6] We choose the highest quality chips – which introduce the largest upstream emissions (Quinn et al., 2020).

[a] We assume 48E credits also support the cost of battery storage systems.

Source: (IRA, 2022)

Credit 45V depends on the ammonia plants' life-cycle CIs. Credit 45Q depends on the difference in the direct emissions between the SMR and CCS plants.

CI values vary based on the supply chain of the utilities, feedstocks, and construction materials. Using the results of life-cycle assessments of natural gas, electricity, and biomass, we estimate a range of CI for each technology to quantify supply-chain emissions intensity and life cycle scope uncertainties (Clark et al., 2012; Nicholson & Heath, 2021; Quinn et al., 2020). AP AEC and AP BH2S are eligible for 45V and 45Y or 48E (when AEC and BH2S own low-carbon electricity generation facilities). AP CCS is eligible for 45V or 45Q and 45Y or 48E (when CCS owns low-carbon electricity generation facilities).

Given the policy incentives and CIs, the cash-equivalent tax credits the ammonia plants will receive can be modeled as follows:

$$\begin{gathered}\boldsymbol{Credits_j(T) = max\left[45V * \dot{m}_{H_2}, 45Q * \dot{m}_{H_2} * \left(CI_{SMR} - CI_j\right)\right] +} \\ \boldsymbol{max\left[CAPEX_{wind\,farm,j} * 48E, \left(E_{\mathrm{AP}} + E_{\mathrm{market}}\right) * 45Y\right]}\end{gathered} \tag{3}$$

$$\boldsymbol{Credits_{CE_j}\left(T \middle| \left|Tax_j(T)\right| > Credits_j(T)\right) = Credits_j(T)} \tag{4a}$$

$$\begin{gathered}\boldsymbol{Credits_{CE_j}\left(T \middle| \left|Tax_j(T)\right| < Credits_j(T)\right) = -Tax_j(T)} \\ \boldsymbol{+F_t * \left(Credits_j(T) + Tax_j(T)\right)}\end{gathered} \tag{4b}$$

where $\boldsymbol{Credits_j(T)}$ is the amount of tax credits the plant $\boldsymbol{j}$ legally qualifies for, and $Credits_{CE_j}$ is the cash-equivalent tax credit which takes transaction costs from “transferability” into account (see Table 3). 45V is a piecewise function of CI – corresponding to the values in Table 2, and has a lifetime of 10 years from the start of plant operation. 45Q is a constant, \$85/tCO_2, and non-zero for the first ten years of operation. 48E is the ITC factor applied to the CAPEX of the wind farm and battery facility[7] – where the CAPEX is a function of the nameplate capacity of the wind and battery storage (see scenarios below). 45Y is the PTC associated with the wind farm, which is mutually exclusive with 48E and is a function of the sum of the electricity supply to the AP plant ($\boldsymbol{E_{\mathrm{AP}}}$) and excess electricity ($\boldsymbol{E_{\mathrm{market}}}$) sold to third parties. $\boldsymbol{\dot{m}_{H2}}$ is the monthly flowrate of H_2. $\boldsymbol{F_t}$ is an exchange rate of USD per tax credit (see Table 3). We assume the excess tax credits are sold to third parties for cents on the dollar after the initial “direct pay” period of five years (see Table 3).

The cash-equivalent tax credits (eq. 4a-b) are not always equal to the nominal tax credits because there are cases where there is not enough income tax to abate with the tax credits. In these cases, we capture this effect by abating the entirety of the income tax and adding the remaining tax credits at a fraction of their value to quantify the transaction costs of “transferability”. When the tax credits are less than the income tax, the cash equivalent tax

[7] We will refer to the wind farm and battery storage facility as a hybrid wind farm.

credits equal the total credits. We assume all tax credits, except for 45Y, qualify for “direct pay” for the first five years of operation (Ben-Yosef, 2023).

Table 3 IRA tax credit market assumptions

Time	Value, $/TC	Notes	Source
Years 0-5 of operation	1	Per IRS “direct pay” guidelines published in June.	(Ben-Yosef, 2023; Chang, 2023; IRS, 2022)
2031-2032	Uniform (0.6,0.85)	Early industry prediction	(Burton, 2019; McKenna et al., 2022; *Renewable Energy Incentives from the Inflation Reduction Act*, 2022)
2032-2033	Uniform (0.7,0.9)	Early industry prediction	
2033-2034	Uniform (0.75,0.925)	Early industry prediction	
2034-2035	Uniform (0.8,0.95)	Early industry prediction	
2035-onwards	Uniform (0.85,0.95)	Early industry prediction	

3.2.1. Baseline scenarios

The CI of electricity inputs is important for LCAP, especially the AEC technology option, to be qualified for policy support. We, therefore, consider three scenarios of how an AP plant can source its electricity demand (Table 4).

For scenario A, we consider the life-cycle assessment (LCA) CI of fuel used in the power generation sector. The lower bound for the LCA CI reflects only emissions at the point of combustion, while the upper bound considers upstream emissions (from “cradle to gate”). All our AP plants source electricity from the grid.

For scenarios B and C, we consider IRA’s subsidies and how they impact LCAP economics when combined with upfront investments in wind and battery (scenario B) or locking into a long-term PPA with a renewable developer (scenario C). Scenario B represents a business model whereby a LCAP plant builds and owns renewable generation to feed into AP. It is an integrated business model whereby the AP producer invests in a wind farm with a battery facility near the main AP plant. In this case, in addition to other IRA policy supports, the AP plant owner can claim 45Y or 48E tax credits as generation from wind is considered a low-carbon, clean electricity source. The downside of this case is the upfront funding for the wind and battery facilities.

We chose to let the AP SMR baseline not be subject to the conditions of scenarios B and C. Instead, we let the AP SMR benchmark be under 2026A conditions as that is the traditional configuration of AP.

Table 4 Business models and policy scenarios.

Electricity source scenarios	AP SMR (Baseline technology)	Low carbon AP

Scenario A: "IRA compatible" US power grid (with a range of LCA of fuels): Grid electricity (2023-2035) – EIA AEO 2023 scenario (CO_2 intensity)	Yes	Yes
Scenario B: "Build and own" a wind farm with a battery that powers the AP processes (upfront CAPEX-intensive, benefit of low marginal cost of electricity generation)[A]	No	Yes
Scenario C: Power Purchase Agreement (PPA) with a wind farm with a battery (OPEX-intensive, electricity purchase paid at the LCOE of wind farm with battery)[A]	No	Yes
[A] We developed an optimization model to minimize the CAPEX of the wind and battery system. The main constraint of this system is constant electric output. For more details, see section D.		

Notes: "No" means we do not consider this case for the baseline AP SMR technology.

On the other hand, scenario C outlines a business model whereby the LCAP plant signs a corporate Power Purchase Agreement (PPA) with a renewable developer. In this case, the renewable developer invests in a new hybrid wind farm and sells this power to the AP plant under a long-term fixed-price PPA. In this case, the AP plant is forgoing the 45Y or 48E tax credit program (as the AP plant is not the wind park owner), but it is also avoiding the upfront wind and battery investment cost. Thus, comparing scenarios B and C will show the implication of the two business models on the economics of LCAP.

In both cases, having a battery helps modulate wind power generation fluctuations. The cost of a battery facility can be considered an opportunity cost of renewable electricity matching to ensure that green hydrogen truly consumes renewable power in line with developments in Europe's green hydrogen regulatory landscape and as suggested by Ricks et al. (2022) for the US low-carbon hydrogen investments to be qualified for IRA supports.

There is a considerable debate regarding the time resolution of this matching requirement (e.g., yearly, monthly, or hourly; see §3.3.2.2) because different time resolutions will have a significant impact on carbon emissions (for a detailed discussion of this question see Ricks et al., 2022). We consider the ***monthly*** matching of renewable electricity to fuel hydrogen production under the AEC pathway for the baseline scenarios. This assumption is consistent with the recently approved European regulation requiring hourly matching. Still, citing short-term technological barriers, this regulation created a grace period until 2030, when only monthly matching is required (COMMISSION DELEGATED REGULATION (EU) 2023/1184, 2023). We offer sensitivity analysis modeling yearly and hourly matching requirements for the AEC pathway (see §3.3.2.2). Lastly, by design, scenarios B and C also meet the deliverability (we assume the AP plant is located in the same area as the wind farm) and additionality (capex of the wind farm is paid by the AP plant) requirements.

We should note that the fuel's LCA assumptions are consistent with the ones we use for feedstock (AP CCS and AP BH2S). Regarding electricity grid CI, the AP plant is assumed to be in a range of locations across the US, so the EIA's 2023[8] average US industrial electricity mix predictions are used for scenario A (EIA, 2023) (see SI H for electricity prices in the model). We utilize the wind and battery CAPEX predictions by Bistline et al. (2023) for scenarios B and C.

[8] The EIA model the IRA under their 2023 Annual Energy Outlook report.

Because time dimensions are important (US power grid decarbonization pace and cost reduction and technology improvements of low carbon energy sources[9]), we are conducting this analysis assuming AP's start of operations in 2026 and 2033. We will refer to these scenarios by the year when operations begin. For example, scenario A in 2026 will be 2026A. Thus, comparing results for 2026 and 2033 will reveal the implications of cost and grid CI reduction on the economics of low-carbon AP. For technologies in 2033, we assume the equity-share of the FCI appreciates at the risk-free rate of 4.25 percent (Damodaran, 2023).

3.2.2. Sensitivity analyses

We analyze two sets of sensitivities critical to the economics of LCAP under the IRA framework – a potential impact of the EU's Carbon Border Adjustment Mechanism (CBAM) and the implications of matching rules for renewable generation with hydrogen production.

3.2.2.1. Sensitivity analysis 1: Export to the EU under the Carbon Border Adjustment Mechanism

The EU is the third largest importer of US-based ammonia production in 2021 ((Observatory of Economic Complexity, 2023). The EU agreed to phase in CBAM from 2027, and the scope is widened to include hydrogen and ammonia. Therefore, we also model a CBAM sensitivity scenario in which ammonia exports to the EU are subject to its carbon tax. Thus, the baseline scenarios are analyzed with and without an EU carbon tax mechanism. The objective is to gauge the impact of IRA and CBAM policies on the economics of US-based AP.

We model this sensitivity scenario by implementing a carbon tax. The European cap is set at the average CI of the top 10% least emissive AP production facilities (McDonald, 2023) – which starts at 8.82 $KgCO_2e/KgH_2$ and decreases by 1.4% per year as per European Commission and literature estimates (European Commission, 2023; Kakoulaki et al., 2021; McDonald, 2023). Any additional emissions above the cap must be penalized by an equivalent purchase of CBAM certificates. We price the CBAM certificates as uniformly distributed between $35-100/tCO2 – corresponding to the latest EU ETS CO2 price range (McDonald, 2023).

Thus, when the CI difference between the EU cap and the US AP technology is negative (meaning the US AP technology is more emissive), the US AP plant incurs a cost, decreasing its cash flow in proportion to the magnitude of the CI difference and CBAM certificate price. In contrast, when the margin between the EU cap and US technology is positive, it leads to a boosted cash flow from the surplus CBAM certificate sales. Thus, we implicitly assume here that the LCAP plant can sell surplus CBAM certificates to other carbon-intensive AP exporters who want to sell their products in the EU; that is, there is potentially a trading scheme for CBAM certificates available for AP exporters and that these certificate prices are linked to the EU ETS price.

3.2.2.2. Sensitivity analysis 2: Implications of matching renewable generation with hydrogen production

Unsteady state operation of the Haber-Bosch process negatively affects its performance (Armijo & Philibert, 2020). The Haber-Bosch process is designed to operate at a steady state. Thus, for

[9] Such as capex of AEC, wind (land-based) and batteries, wind farm hub height

this sensitivity case, a battery facility is assumed to be sufficient to ensure a constant output of a wind park to fuel the AP plants[10].

We explore yearly, monthly, and hourly matching with a hybrid wind farm and find the appropriate facility capacities through an optimization model (see SI D). The strict hourly matching scenario comes with a relatively high battery cost (due to the sizing of wind and battery facilities). There is a debate regarding whether such a strict hourly matching will impede the roll-out of green hydrogen (Cybulsky et al., 2023; "Green Hydrogen: An Assessment of near-Term Power Matching Requirements," 2023; Ricks et al., 2023; Riley et al., 2023; Ruhnau & Schiele, 2023; Vargas et al., 2023). On the other hand, economically more advantageous, relaxed, yearly matched renewable electricity and hydrogen production will incur additional emissions, depending on the grid CI. We explore the impact of yearly and hourly matching on the economic benefits of low-carbon ammonia.

3.3. Model validation, robustness, and convergence of the results

Our plant-level costing model appears credible when benchmarked against data produced by the IEA's Ammonia Technology Roadmap (IEA, 2021). We created a deterministic version of the current model and tested input and sensitivity parameters the IEA used to recreate similar levelized costs and uncertainty ranges. We analyze these results in SI G.

To ensure probabilistic convergence, our stochastic model underwent 4,000 simulation runs, confirmed by a convergence analysis consisting of testing the change in model outputs for a given change of additional simulations. More details can be found in SI G and supplementary files.

Further validation was achieved through a sensitivity analysis, which examined key input assumptions to assess the model's quality and directional impact based on changes to the input parameters (see SI G). Collectively, these evaluations affirm that the model yields economically sound results.

4. Results and Discussion

This section discusses the near-term (2026) potential deployment of LCAP under the IRA framework. Then, we discuss results for the medium term (2033), focusing also on the cost reduction potential of low-carbon technologies and what this means for investments in AP under the IRA. It then discusses the carbon abatement cost (CAC) for the LCAP technologies, comparing it with the social cost of carbon (EPA, 2022) and selected carbon prices under other policy regimes. Furthermore, we discuss the shortcomings of the levelized cost approach compared to our NPV approach under the IRA framework. We include the NPV impacts of CBAM on all AP pathways as a case study. Finally, we discuss the implications of optimally sizing the hybrid wind farm under yearly, monthly, and hourly renewable electricity and hydrogen production matching rules.

4.1. Near-term deployment of low-carbon ammonia

We systematically compare AP SMR, AP CCS, AP BH2S, and AP AEC technologies in various scenarios we consider. We illustrate the economic performance in Figure 4.

[10] For the formulation of the optimization model, see SI D. For the justification of a constant electric output, we perform an in-depth literature review assessing the impact of a variable electricity input into AP (see section F).

4.1.1. Connecting to the US power grid

AP SMR outperforms all low-carbon alternatives in scenario 2026A. AP SMR only requires 64 MW_e to operate, while AP CCS, AP BH2S, and AP AEC require 117 MW_e, 127 MW_e, and 910-1010 MW_e, respectively[11]. For SMR, CCS, and BH2S, the electrical energy demand is almost an order of magnitude smaller than AP AEC because the high energy density (fossil or bioenergy) feedstock makes up for the difference. AP AEC utilizes water as feedstock, so all energy originates from electricity.

Furthermore, AP SMR is hedged against the NH3 market price fluctuations because of the high correlation with the input cost (natural gas prices). In this regard, AP CCS is also hedged. However, AP CCS underperforms compared to AP SMR as AP CCS exchanges the electric penalty (53 MW_e) for environmental performance gains (AP SMR has an average CI of 8.9 Kg CO_2 / Kg H_2 versus AP CCS' 1.45 Kg CO_2 / Kg H_2)[12]. Furthermore, the CCS module has a significant CAPEX (52% of the SMR CAPEX). Under the IRA, the additional electricity demand of AP CCS in scenario A increases emissions and prevents maximal IRA support. Hence, the environmental performance gains of AP CCS are not optimally attained in scenario A with 45V or 45Q programs (showing a difference in the NPV of 21 \$/MT NH_3 between no policy and IRA scenarios). The policy support is insufficient to displace the relative costs associated with CCS (-34 \$/MT NH_3 difference between AP SMR and AP CCS median performance in the no policy scenario).

AP SMR also outperforms AP BH2S as the additional feedstock costs (\$125MM/yr versus \$169MM/yr) and electricity costs (\$25MM/yr versus \$50MM/yr) cause a median no policy cost difference of -29 \$/MT NH_3 and are not displaced by the 10-year policy support (17 \$/MT NH_3). Furthermore, AP BH2S has a higher CAPEX (24% of the AP SMR CAPEX) than AP SMR. The lackluster policy support for BH2S is due to the high grid CI (1.8 – 3.0 Kg CO_2/Kg H_2), which only qualifies it for \$0.75-0.6/Kg H_2 of 45V policy support. Even though natural gas (and NH3) prices are at an all-time high as a repercussion of the energy crisis brought by the Russia-Ukraine war, AP BH2S is not likely to outperform AP SMR under this grid connection scenario in the near term. The relatively large uncertainty bars around AP BH2S (-83 to 156 \$/MT NH_3 versus -67 to 137 \$/MT NH_3 for AP SMR) result from uncorrelated feedstock and NH3 markets.

Finally, AP SMR outperforms AP AEC by such a large margin that even the 75th percentile performance of AP AEC does not outperform the 25th percentile AP SMR. The AP AEC electricity costs are sixteen times higher (\$398MM/yr) than the AP SMR (\$25MM/yr). Furthermore, AP AEC does not qualify for any policy support because its CI is twice AP SMR's at 17-31 Kg CO_2 / Kg H_2 – values in the range Ricks et al. (2023) also derived. Even considering the potential boost to the grid decarbonization envisaged in the IRA, the US electric grid is too carbon intensive, making AP AEC ineligible for any subsidies.

In conclusion, the LCAP support provided by IRA programs is insufficient relative to the additional costs of improving the environmental performance of AP through CCS, BH2S, or AEC technologies. Furthermore, the grid under the IRA is decarbonizing too slowly to enable low-carbon technologies to compete with AP SMR. CCS incurs too much electricity costs, and the

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[11] Owing to the scale at which we model the AP plants, 2717 TPD NH3, the electricity requirements we report are large. An ammonia plant of this size is on the larger end of US AP (Amhamed et al., 2022). More details are in SI A and B.

[12] In the conventional SMR process, excess high-pressure steam is generated. This steam can be sold or used to generate power. In the case of AP CCS, the high-pressure steam is used to regenerate the amine-based solvent that captures the CO_2 (IEAGHG, 2017; Lewis et al., 2022). Losing the steam energy, AP CCS cannot use that energy across other unit operations.

45Q/45V policy support is insufficient to displace the additional cost. BH2S suffers from the same weakness. AP AEC is the worst performer as it has sixteen times the electricity cost of AP SMR, emits twice as much CO_2 as AP SMR, and, for this reason, has no policy support.

4.1.2. Connecting to a hybrid wind farm

As mentioned earlier, scenarios B and C aggregately represent zero-carbon electricity generation alternatives to the grid connection in scenario A. However, separately, scenarios B and C serve as a comparative study to understand the impact of balancing the CAPEX-dominant AP business model (in the case of "Build and Own," scenario B) versus the OPEX-dominant model (under "Power Purchase Agreement," scenario C) under zero electric emissions.

Investors in the Build-and-Own (B) scenario would expect the sum of the benefits from either 48E or 45Y credits in conjunction with selling surplus electricity to produce a net positive cash flow from the hybrid wind farm. The AP investors in the PPA (C) scenario would prefer to avoid the risk of investing capital (to own the hybrid wind farm) upfront and instead sign a long-term PPA and pay a fixed price equal to the LCOE needed to provide firm renewable power to their AP plant.

Owing to the significant up-front costs associated with building electric generation in situ, scenario B severely underperforms compared to scenario C. The NPV difference across scenarios B and C for each technology is proportional to the electricity requirements. AP AEC's high electricity demand incurs either (i) a disproportionately large generation facility, and hence CAPEX, relative to the other technologies (scenario B) or (ii) severe electricity costs (scenario C). Thus, AP AEC suffers the most loss from scenario C to B (-$437/tNH3). AP CCS and AP BH2S are more robust to the configuration of the electric supply from the hybrid wind farm at a -$/72tNH3 and -$63/tNH3 loss for both technologies, respectively, from scenarios C to B. The difference between B and C in NPV occurs because the discount rate in the NPV favors spread-out payments, like the PPA – which exposes the investor to less risk. The first 13 years' discounted cash flows comprise approximately 75% of the total NPV, so significant upfront capital investments will penalize the NPV. On the other hand, the PPA payments are spread out over a larger horizon of 40 years and hence cost less than the upfront CAPEX costs of scenario C[13].

Under a hybrid wind farm configuration, AP CCS and AP BH2S are competitive with AP SMR with a PPA business model. The median NPV of AP CCS and AP BH2S ($51/tNH3 and $52/tNH3) is just under the 75th percentile of AP SMR (60/tNH3). Due to higher electricity requirements and cost, AP AEC fails to compete with the average AP SMR NPV ($31/tNH3) in both scenarios (-$438/tNH3 in scenario B and $0/tNH3 for scenario C).

4.1.3. Should low-carbon APs connect to the grid or rely on a hybrid wind farm?

The grid-based business model relies more on the status of the US power markets in terms of its carbon intensity and prices. In contrast, hybrid wind farm business models heavily depend on upfront capital investments in low-carbon generation or long-term contracting with a renewable developer. The central question is whether additional policy support from investing in ensuring zero-carbon electricity generation can enhance the competitiveness of low-carbon technologies.

[13] The project lifetime of wind farm projects is typically in the 20 year range. Since our AP model is 40 years, we make some assumptions regarding replacement costs of the wind turbines after the 20 year mark (see SI E).

In other words, are investors incentivized to curb electric emissions for low-carbon AP, given the anticipated direction of the US power markets?

Comparing different technologies, AP CCS and AP BH2S demonstrate greater resilience against fluctuations in hybrid wind farm costs due to their significantly lower electric demand than AP AEC. Consequently, AP CCS and BH2S exhibit a more diversified risk profile. Both AP CCS and BH2S are influenced by natural gas, bioenergy feedstock, and electric prices. In contrast, AP AEC's diversity is lower, as its feedstock (excluding water) is also the electricity source. Thus, if hybrid wind facilities prove excessively costly, AP AEC faces a significant risk of loss. In contrast, AP BH2S and AP CCS would experience a less pronounced impact (see scenario 2026B in **Error! Reference source not found.**).

From Figure 3, AP BH2S achieves an average CI that varies around the 45V 0.45 $kgCO_2/kgH_2$ threshold (0.28 – 0.54kg O2e/kgH2) in scenarios B and C – so in some simulations, AP BH2S receives only 1$/Kg H_2. The resulting median policy support for BH2S under a renewable electricity source is \$56/MT NH_3. At this policy support level, the NPV gain is negative from grid-supported 2026A AP BH2S to 2026B AP BH2S (-\$30/MT NH_3) – meaning the grid configuration is preferable to in-situ power generation due to the high upfront CAPEX not offset by 45V. From 2026A to 2026C, the NPV gain is positive (\$30/MT NH_3), which shows that contracting with a hybrid wind farm through a PPA is preferable to both the grid connection (scenario A) and building and owning the wind farm directly (scenario B). In 2026C, this performance gain enables AP BH2S to outperform AP SMR (by \$20/tNH3). Nevertheless, AP BH2S is not hedged against NH_3 price drops, unlike AP SMR, a risk investors must consider (see section G). AP CCS achieves similar performance (by \$19/tNH3) while its risk is more diversified.

While we find that CCS and BH2S have been proven as the best low-carbon options, AP BH2S does come with its unique set of limitations we did not capture in our modeling despite its better economic performance against other LCAP options. It relies on a substantial nearby biomass reserve, which may run out, limiting the scalability of AP BH2S, or incur additional costs to grow the biomass *in-situ* – not to mention the considerable land use that may be better allocated to agriculture (Arodudu et al., 2020; T.M. Young, 1991). Algal biomass, for example, costs between \$694-864/MT to grow through pond cultivation, while in our model, we use costs between \$50-118/MT of woody biomass (Klein & Davis, 2021). We chose to use woody biomass because the underlying engineering design of the BH2S techno-economic model relies on NREL's (Spath et al., 2005) rigorous work– which they only performed for woody biomass.

There are also process operation consequences, as biomass is known to vary in quality, thereby creating variable hydrogen output (Armijo & Philibert, 2020)[14]. In contrast, electrolysis is not plagued by this constraint, given water's ubiquity and on-demand production capabilities. In our analysis of 2026B and 2026C, AP AEC not only obtains the full \$3/Kg H_2 45V PTCs but also receives eight times the amount of 48E ITCs than AP BH2S (see Table 5, scenario B) because of an 8-fold difference in electricity requirements. Nevertheless, the cost of the hybrid wind system for AP AEC is too high in proportion to the IRA PTCs awarded – as we see that on a per capital (scenario B) basis, 48E tax credits are not sufficient (for more direct visualization, see **Error! Reference source not found.**) – making the technology largely uneconomic compared

[14] Unsteady state operation of the Haber-Bosch process negatively affects its performance (Armijo & Philibert, 2020). The Haber-Bosch process is designed to operate at a steady state (and we assume steady state) – under a biomass feedstock, this condition may not be the case.

to SMR and other low-carbon AP options even under this level of support. The other (mutually exclusive) alternative, 45Y PTCs, is less valuable than 48E credits and is never chosen by the model (see Table 5).

4.2. Medium-term deployment of low-carbon ammonia

4.2.1. Economic performance shifts from near-term scenarios

Fast forward to 2033A, and the landscape shifts. Despite predictions of significant cost reductions for electrolysis impacting economic performance, AP AEC still fails to compete when it is off taking electricity from the grid – AP AEC's 75th percentile performance in 2033A is still below AP SMR's 25th percentile by $10/tNH3. Unlikely high NH3 prices and low electricity costs characterize AP AEC's 75th percentile and above performance. In 2033A, AP CCS and AP BH2S performance relative to AP SMR remains the same as in 2026A.

AP SMR, AP CCS, and AP BH2S still outperform AP AEC despite technology cost reductions from deployment and R&D – which are observed to increase AP AEC's NPV by $3/MT NH3 from 2026A to 2033A. We assume in our analysis that AP CCS and AP BH2S do not experience cost reductions[15], as these processes are not as easily deployable as AP AEC, which benefits from its modularity and scale versatility to undergo a high learning rate (Lee et al., 2021).

Technology cost reductions are generally insufficient to make the AP AEC a viable alternative to AP SMR in a grid configuration unless the grid CI is very low. Only in unlikely high NH3 prices and low electricity prices AP BH2S and AP AEC will become better options than AP SMR because (i) they are not hedged by NG markets and (ii) their economics are more sensitive to electricity prices than AP SMR.

In 2033B, we find the most improvement to the economics of AP AEC. AP AEC improves its performance from 2026B by $306/tNH3 because of a non-linear effect stemming from a reduction in AEC stack costs and wind CAPEX costs in conjunction with increasing hub heights and capacity factors for wind technology in 2033. These improvements are also observed for AP CCS ($38/tNH3) and AP BH2S ($29/tNH3) but are not as large as AP AEC due to the difference in electricity demand. Still, AP CCS and AP BH2S outperform AP AEC by a large margin ($151/tNH3 and $152/tNH3, respectively).

In 2033C, technology cost reductions of AEC and the hybrid wind farm, combined with now high 45V IRA-eligibility, produce an average boost in NPV for AP AEC of $44/MT NH3 from 2033A – which makes AEC surpass AP SMR by $11/tNH3. AP CCS and AP BH2S also experience identical hybrid wind farm cost reductions in cases B and C. The NPV response, however, is much less as the scale of the hybrid wind farm required is almost an order of magnitude smaller than AP AEC's (refer to SI G).

In 2033A, the NPV distribution of all technologies stretches across all scenarios because of compound uncertainty from our Brownian motion modeling of NH_3, natural gas, and electricity prices. The implications of the compounding market effects have a directional effect on AP BH2S, which can be observed in scenario A. As natural gas prices return to the normal range,

[15] For example, CCS demonstration projects cost on the order of US$1 billion each – hence the number of projects is low (Reiner, 2016; Scott et al., 2013). The driver of the learning rate is the number of units deployed among other factors.

the NH3 prices follow. The decreasing NH3 prices and lack of hedging cause AP BH2S to shift downwards by -\$11/tNH3 at the mean, by \$1/tNH3 at the 75th percentile, and by \$19/tNH3 at the 25th percentile.

4.2.2. Technology cost reductions and the opportunity cost of waiting

By 2033, the reductions in technology costs for electrolysis and hybrid wind farms offset additional policy support opportunity costs between 2026 and 2033. The median NPV difference between 2026C and 2033C AP AEC is \$300/MT NH3. In scenario B, AP AEC only improved by \$40/MT NH3 from 2026 to 2033. The discount rate causes an asymmetric response to technology improvements and cost reductions across scenarios.

The increasing value of waiting arises from two sources. Firstly, there are direct cost reductions in AEC, wind, and battery systems. Secondly, wind farm capacity factors are anticipated to rise as average hub heights shift from 90m in 2023 to 120m in 2030 due to enhanced turbine design, optimizing placement in higher wind velocity zones (Observatory of Economic Complexity, 2023). Combining cost reductions with increasing capacity factors results in non-linear NPV increments.

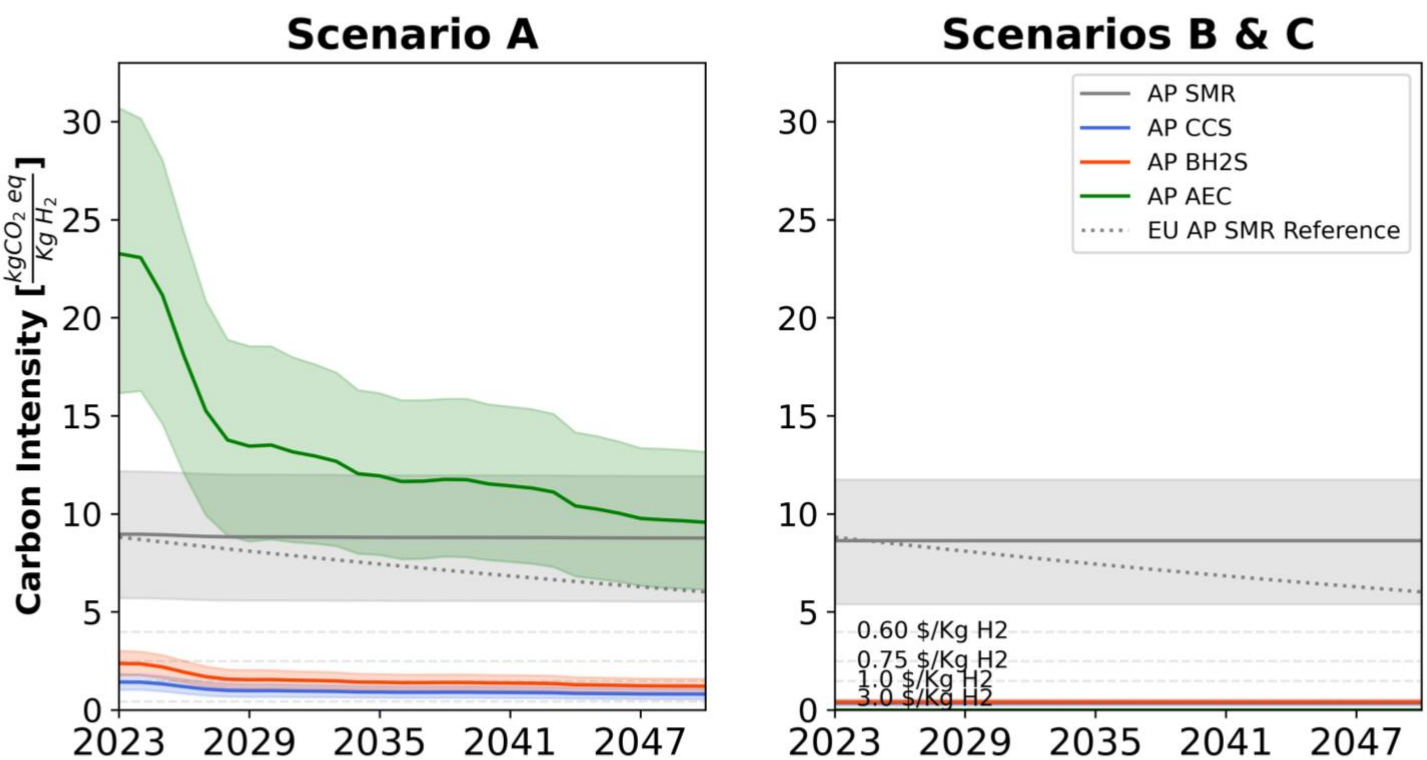

Figure 3 Carbon intensity of AP technologies: grid versus hybrid wind farm

By the year 2033, there are competing factors at play that influence investment decisions in AP AEC. On one side, the expectations of cost reduction and technological improvements of renewable generation technologies, including AEC, could incentivize investors to delay their investments. Conversely, the looming expiration dates of the IRA programs could prompt investors to invest immediately to maximize policy support.

In conclusion, investors are incentivized to wait until at least 2030 to invest in AP AEC plants to maximize technology and deployment-driven cost reduction – indeed, as a function of the expected growth and volatility in the value gap[16]. This dynamic could lead to a situation where the anticipated immediate deployment of electrolysis or hybrid wind farms for AP is delayed, as investors may be waiting for further technological cost reductions. Paradoxically, if the technology is not deployed, these cost reductions could take longer to materialize, creating a "chicken-or-the-egg" problem that is at odds with the intent of the IRA. Thus, if the highest tranche of 45V policy support were to be increased to a level that lets 2026C AP AEC perform on the same level as 2033C AP AEC, the new highest 45V credit would be \$4.8/Kg H2– 60% larger than the current 45V support[17]. 92% of the support increase would be due to technological improvements and the remaining 8% due to capital appreciation at the risk-free rate.

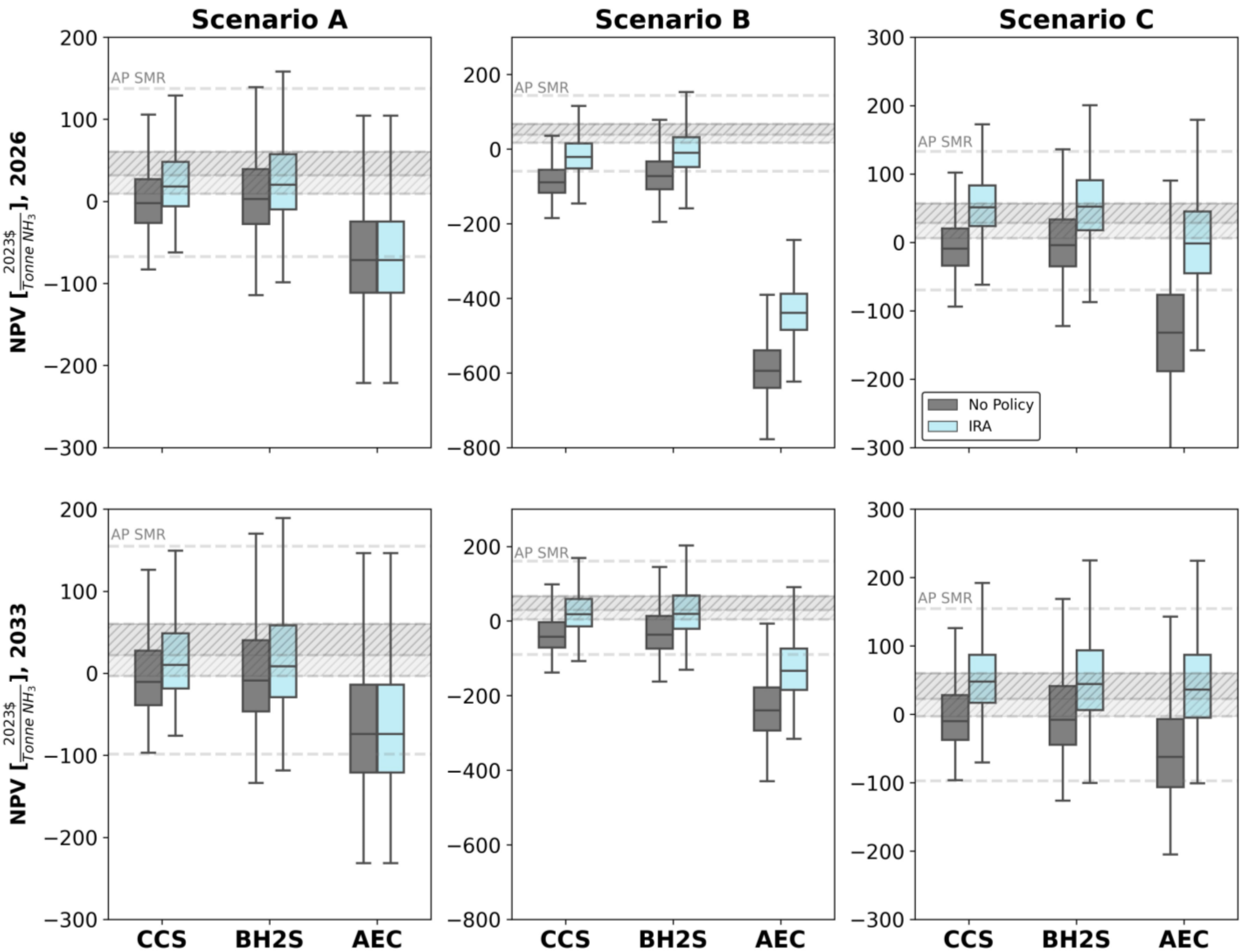

Figure 4 NPV of low-carbon AP technologies

Notes: The NPVs are benchmarked against a control scenario with no policy and AP SMR. Scenarios B and C are monthly matched to the wind and battery system.

[16] This effect has been studied before. The interested reader might look at an interesting study regarding investor optionality in green vehicle investment by Dimanchev et al. (2023).

[17] This value was calculated by increasing the highest tranche of 45V credits (\$3/kg) until 2026C AP AEC's NPV matches 2033C AP AEC's NPV.

4.3. Carbon abatement costs of low-carbon ammonia

The incentives offered by the IRA are sufficient to render low-carbon technologies competitive with AP SMR in some scenarios. However, this outcome is tied closely to the context of U.S. policy. The bulk of existing literature on the impact of carbon policy on AP is focused on a straightforward carbon tax scenario, where tax is proportionate to emissions (Lee et al., 2021; Sousa et al., 2022). Interestingly, while U.S. policies tend to bolster the profitability of low-carbon technologies, EU policies aim to curtail the profitability of carbon emitters by putting a price on carbon emissions (via EU ETS). This difference offers a compelling opportunity to juxtapose the effects of structural policy attributes under a common metric.

A valuable measure in this context could be the carbon abatement cost (CAC), which quantifies the cost to the taxpayer of bringing low-carbon technologies to commercialization, normalized by the mitigated emissions over the lifetime of the plant (see eq.5). The CAC is presented in Figure 5.

$$\boldsymbol{CAC_j} = \sum_{T=S+C}^{L+S+C} \frac{\dfrac{\boldsymbol{Credits}_{\mathrm{j}(T)}}{[\mathbf{1} + \boldsymbol{d_s}]^{T-S}}}{\sum_{T=S+C}^{L+S+C} \left[\dfrac{\boldsymbol{M}_{\cdot H2}\left(\boldsymbol{CI_{SMR}} - \boldsymbol{CI_j}\right)}{[\mathbf{1} + \boldsymbol{d_s}]^{T-S}}\right]} \tag{5}$$

where $\boldsymbol{L} + \boldsymbol{S} + \boldsymbol{C}$ represents the operating lifetime, the month the plant begins to be built, and the construction period, respectively. The denominator represents the total abated emissions as a Riemann sum of the CO_2 at all periods. Both the carbon and credits are discounted to the present value. The discount rate for the CAC is set to two percent – in line with EPA's estimates of the social cost of carbon (EPA, 2022).

In scenario A, the CAC is below the lower end of the social cost of carbon. Simultaneously, the NPV of AP CCS and BH2S is primarily positive, implying that these technologies can be profitable while costing less than the predicted economic cost from carbon's associated economic damages. Moreover, we note that most of the CAC hovers around 35-53 $/tCO2 for AP CCS and 28-45 $/tCO2 for AP BH2S. These figures are in line with the CO_2 prices in the EU ETS. For AP CCS, our simulations reveal that the preferred policy program is 45V over 45Q because the difference in direct emissions between SMR and CCS is smaller than 45V credits at the $1/kg H_2 level. Table 5 shows that CCS does opt for 45Q credits sometimes, depending on its CI. Across all scenarios, AP CCS opts for 45V over 45Q in 89% of simulations.

Overall, AP BH2S is marginally cheaper to fund than AP CCS and has a better economic performance. However, considering the limitations of BH2S previously discussed, AP CCS seems to be a viable option for investors aiming to produce low-carbon ammonia.

In scenario B, the investor bears the high initial costs of the hybrid wind farm, anticipating a return on investment through two mechanisms: (i) support from 48E or 45Y tax credit programs and (ii) selling excess electricity resulting from the oversizing of the hybrid wind system to guarantee continuous firm electricity supply. Should electricity prices soar, this business model could become appealing as the excess electricity will offset more battery costs. We model the price at which the excess electricity is sold as the greater value between the PPA price of the wind farm without battery storage and the market electricity price from scenario A. With this reasoning in mind, we should note the following findings:

(1) The initial high costs of the hybrid wind farm and the abundance of 48E credits make the CAC of AP AEC higher than the social carbon costs in 2026B (by $28/tCO2 or +13%), implying that the IRA might be overpaying for carbon reduction via AEC technology pathway in the near term. However, by 2033, due to decreasing costs, the AEC CAC falls below the social cost of carbon ($-34/tCO2 or -16%), suggesting that the IRA might cost-efficiently fund AP AEC – albeit less efficiently than AP CCS and AP BH2S. Moreover, the range of values we use for 48E is 30-40% ITC; should an AP AEC process qualify for the maximum 50%[18], its 2033 CAC could match or surpass the social cost.

(2) The financial advantages of selling excess electricity do not compensate for the additional CAPEX because of anticipated low electricity and competitive PPA prices from wind-only farms. This suggests the IRA might be investing too much in AEC projects with a low-profit chance.

In scenario C, the public will spend the same amount as in scenario B. However, in our depiction of C, the 45Y/48E credits are inherently factored into the PPA price and are not explicitly shown in the chart.

The CAC metric we employ measures the total credits awarded by the IRS to the private sector through low-carbon AP. In a unique case where the market value of a tax credit (TC) is $1/TC, we determine the CAC as the cash-equivalent tax credit. AP Investors considering any IRA-supported business model can only aspire to attain this "potential" tax credit as transaction costs are expected by the industry (see Table 3). In the next section, we elucidate this transaction cost by comparing levelized cost versus NPV approaches.

[18] 50-60% ITC can be achieved by being in (i) an energy community, and (ii) meeting domestic manufacturing requirements– where each criteria met will result in a 10% ITC increment (IRA, 2022).

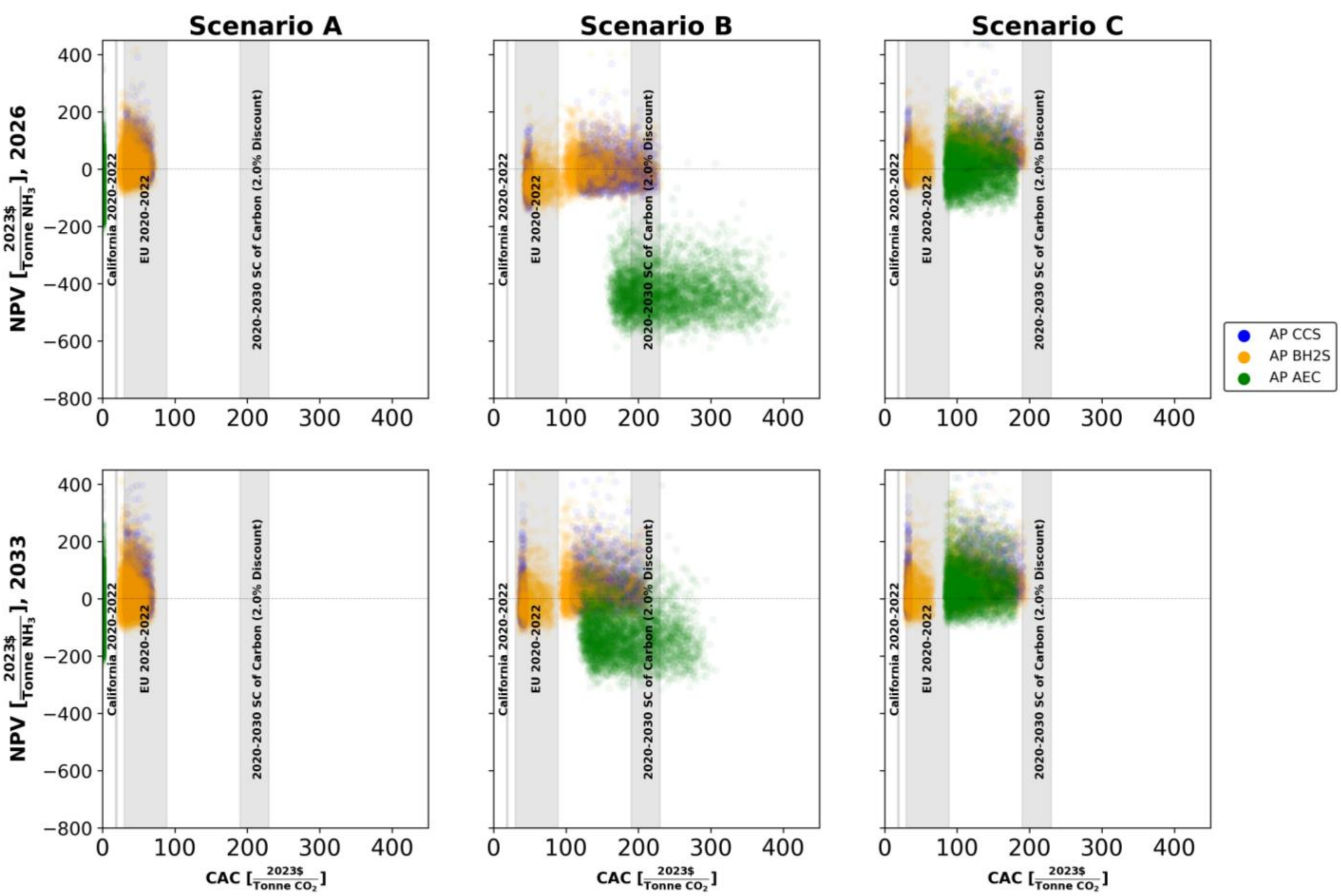

Figure 5 NPV versus carbon abatement cost

Sources: Foreign tax quantities were obtained from the IEA (IEA, 2021); California tax prices from 2020-2022 are displayed as a band and come from the EIA (Brown, 2022).

4.4. Over-estimating policy support under the levelized cost approach

The levelized cost approach, commonly used in hydrogen and ammonia production studies, concentrates on the impact of engineering variables on cost ((Arora et al., 2016; Campion et al., 2022; del Pozo & Cloete, 2022; Gomez et al., 2020; Guerra et al., 2020; IEAGHG, 2017; Jenkins & Ricks, 2023; Lee et al., 2021; Lewis et al., 2022; Osman et al., 2020; K. H. R. Rouwenhorst et al., 2019; Sánchez et al., 2019; Sousa et al., 2022; Tock et al., 2013; Tunå et al., 2014; G. Wang et al., 2020b; Zhang et al., 2020)). However, in papers focusing on the IRA, it has been assumed that deducting eligible tax credits from the cost basis is a valid modeling approach. For instance, Jenkins et al. (2023) examined the effect of IRA credits on electrolysis for hydrogen production across various technology scenarios and developed a levelized cost of hydrogen (LCOH) calculator. In this tool, altering the value of the hydrogen PTC would directly be deducted from the estimated LCOH by the PTC amount. Cheng et al. (2023) also employ the same levelized cost approach and report remarkable economic performance for low-carbon technologies (SMR CCS, electrolysis, and BH2S).

Figure 6 presents the total tax credit policy support on a per-kilogram-of-hydrogen basis, making the support measures easily interpretable. For instance, technologies receiving \$3/KgH2in support will be plotted at \$3 on the tax credits Y-axis. This allows for a direct comparison of the total tax credits received by an ammonia investor against legislative provisions, taxpayer expectations, and the investor's valuation of these credits. In the subsequent results and discussion, we first describe the potential tax credits and the criteria for technology qualification. We then explore the transaction costs associated with each technology and scenario and examine how discount rates affect the value of the tax credits.

4.4.1. Potential tax credits

In our analysis for scenario 2026A, AP CCS receives $1.00/KgH2, aligning with the $1.00 per kilogram threshold set by the 45V program. Given the option between the 45Q and 45V programs and the input dataset, CCS chooses 45V credits in 89% of simulations; the 45Q program is selected in only 11% of simulations for carbon capture ammonia in this scenario. Turning to AP BH2S, the tax credit range is notably broader due to the variable carbon intensity of biomass, which fluctuates around the $1.00 and $0.75 per kilogram thresholds. Alkaline electrolysis, conversely, does not benefit from any tax credits in scenario 2026A.

In scenario 2026B, AP CCS attains the maximum $3/kgH2 tax credit under the 45V program in 75.5% of simulations. However, in 24.5% of simulations, it only garners $1.00/kgH2, making 45Q credits occasionally more favorable, though such cases are rare in this scenario. Credits under programs 48E and 45Y contribute to carbon capture ammonia's support. While all low-carbon technologies can opt between 48E and 45Y, 48E credits are consistently more attractive. If the energy efficiency per unit CAPEX for the hybrid wind facility were larger (i.e., higher capacity factors or lower system CAPEX), 45Y would be preferable.

For AP CCS, the total policy support exceeds $3/kgH2, reaching $3.48/kgH2 when 48E credits are included, attributing approximately $0.48/kgH2 to these credits. A similar pattern is seen for AP BH2S, with the main difference being its slightly higher emission levels. This results in more frequent qualification for the $1.00/kgH2 45V credits.

AP AEC garners additional policy support beyond its 45V qualification of $3/kgH2. The high electricity demand makes it conducive for a large-scale hybrid wind farm, resulting in substantial 48E credits. Consequently, the total value of 48E credits is estimated at $3.07/kgH2.

In scenario 2026C, separating the hybrid wind farm and AP complicates the perception of actual policy support required for low-carbon AP. Despite this, the public expenditure remains consistent in scenarios B and C due to the principle of additionality (Ricks et al., 2023). All new green hydrogen capacities qualify for electricity-related tax credits. Our quantification reveals that the value of these credits is roughly on par with the $3/kgH2 offered by the 45V program. This signifies a substantial public investment in the electricity and hydrogen infrastructure essential for green hydrogen production.

Fast forward to scenario 2033B, there is a notable decline in total policy support. AP CCS sees its potential tax credits diminish from $3.48/kgH2 in 2026 to $3.22 in 2033. A similar trend is observed for AP BH2S, with credits falling from $3.42 to $3.19/kgH2. AP AEC faces a more drastic reduction, from $6.07 to $4.51/kgH2, primarily due to technological advancements that lower wind, battery, and electrolysis technologies costs – thereby reducing 48E credits. In contrast, scenarios 2033A and 2033C show no change in policy support, as they lack cost reductions, and their tax credits (45V and 45Q) are determined by carbon intensity rather than capital investment. To observe these changes in policy support more clearly, please see Table 5.

4.4.2. Cash equivalent credits

In scenario A, AP CCS experiences a 6.8% reduction in tax credits when converted from nominal to cash-equivalent terms (at a 2% discount), while AP BH2S sees a 4.6% decrease. These reductions are consistent across time, holding for 2026 and 2033. In scenario B, the deductions rise to 7.6%, 7.7%, and 4.6% for AP CCS, AP BH2S, and AP AEC, respectively. In scenario C, the deductions further escalate to 8.8%, 9.2%, and 8.7% for the same technologies.

Explaining the variance in tax credit deductions across technologies is challenging when relying solely on aggregate metrics like total tax credits. This complexity arises from the interplay among several factors: income tax and profitability, depreciation, loan payments, and the market value of the tax credits themselves. In highly profitable cases, income taxes increase the potential for tax reduction without needing to trade credits, resulting in minimal loss in value. Conversely, an unprofitable process with negative cash flows has no income tax liability, requiring the awarded tax credits to be traded at a lesser value. Adding to this complexity are the effects of depreciation and loan payments, which reduce net revenue and income tax. While these elements act as a tax shield, they can also lower the value of eligible tax credits. Notably, these credits are generally awarded in the first 12 years of operation, during which depreciation and loan payments are still ongoing.

When evaluating the cash-equivalent tax credits discounted at a 9.3% rate, they fall below the potential tax credits in scenarios A and C. However, in scenarios 2026B and 2033B, these cash-equivalent credits can exceed the potential tax credits discounted at a 2% rate. For AP CCS and AP BH2S, the cash-equivalent tax credits discounted at 9.3% closely align with the potential tax credits. AP CCS' potential tax credits are valued at $3.48/kgH2, while the cash-equivalent value is $3.43/kgH2 in 2026 (at a 9.3% rate). Similarly, AP BH2S shows a potential value of $3.42/kgH2 versus a cash-equivalent value of $3.35/kgH2 in 2026. In contrast, AP AEC sees a significant gain in value when discounted at a 9.3% rate compared to a 2% rate. The potential tax credits are valued at $6.07/kgH2, while the cash-equivalent value at a 9.3% discount rate is $6.97 per kilogram in 2026.

In 2033, a similar trend is observed. AP CCS has potential tax credits valued at $3.22/kgH2, with its cash equivalent at $3.09/kgH2. Biomass gasification follows suit, showing a potential value of $3.19/kgH2 and a cash-equivalent value of $3.04/kgH2. The additional value from discounting the cash-equivalent credits at 9.3% diminishes alkaline electrolysis ammonia. The gap narrows from approximately $0.90 to $0.33/kgH2. The potential tax credits are valued at $4.51/kgH2, while the cash equivalent at a 9.3% discount rate is $4.84/kgH2.

Indeed, for all scenarios, we assume that the market value of the tax credits is the same across technologies. This assumption becomes particularly salient in the context of CCS, where both environmental and financial risks related to CO2 leakage present significant challenges (Bartlett & Krupnick, 2019; Herzog, 2011). According to Norton Rose Fulbright, the financial liability for recapture under 45Q credits lasts for 15 years (Burton, 2023; Martin, 2021), thereby increasing the risk profile for tax equity investors. Consequently, the actual market value of these credits may be considerably lower than their nominal value, influencing both investment decisions and the rate of technology adoption (D'Alelio et al., 2022). Therefore, the commonly assumed value of tax credits in fostering AP CCS technologies may be more overestimated than other technologies, necessitating a more comprehensive analysis than what we present.

The value discrepancy across discount rates arises from the uneven temporal distribution of tax credits in scenario B, specifically 48E credits. These are awarded in the first year of operation and represent a substantial initial cash influx to the ammonia production process. Given the lower discount rate applied to this immediate cash injection, as opposed to hydrogen production 9 to 10 years later, the value per kilogram of hydrogen becomes significantly higher. This is especially true for private investors with higher discount rates than public investments.

In conclusion, the general trend shows that the cash-equivalent value of tax credits typically falls short of the nominal value the government offers. Traditional levelized cost approaches have often overlooked this discrepancy, thereby overestimating the actual policy support. As the market value of these tax credits approaches $1 per tax credit, the gap between the levelized cost and net present value methods narrows. However, the actual market value of these credits remains uncertain due to the high-risk nature of these technologies. For instance, investors purchasing future tax credits from a particular low-carbon process risk acquiring ineligible or nonexistent credits if the process fails to meet the requisite carbon intensity levels for qualification. Such risk assessments incur additional verification, compliance, and monitoring costs. Nonetheless, it is reasonable to suggest that the actual value of tax credits could be considerably lower than projected, creating substantial valuation gaps between levelized cost and net present value approaches.

Table 5 Average net present absolute policy support in billion $ by IRA program.

		Policy Support [2023 M$]									
		AP CCS				**AP BH2S**			**AP AEC**		
		45V	**45Q**	**48E**	**45Y**	**45V**	**48E**	**45Y**	**45V**	**48E**	**45Y**
2026	**A**	716	809	0	0	665	0	0	0	0	0
	B	1908	809	556	0	1809	513	0	2369	3341	0
	C	1908	809	0	0	1809	0	0	2369	0	0
2033	**A**	716	809	0	0	665	0	0	0	0	0
	B	1908	809	273	0	1809	252	0	2369	1656	0
	C	1908	809	0	0	1809	0	0	2369	0	0

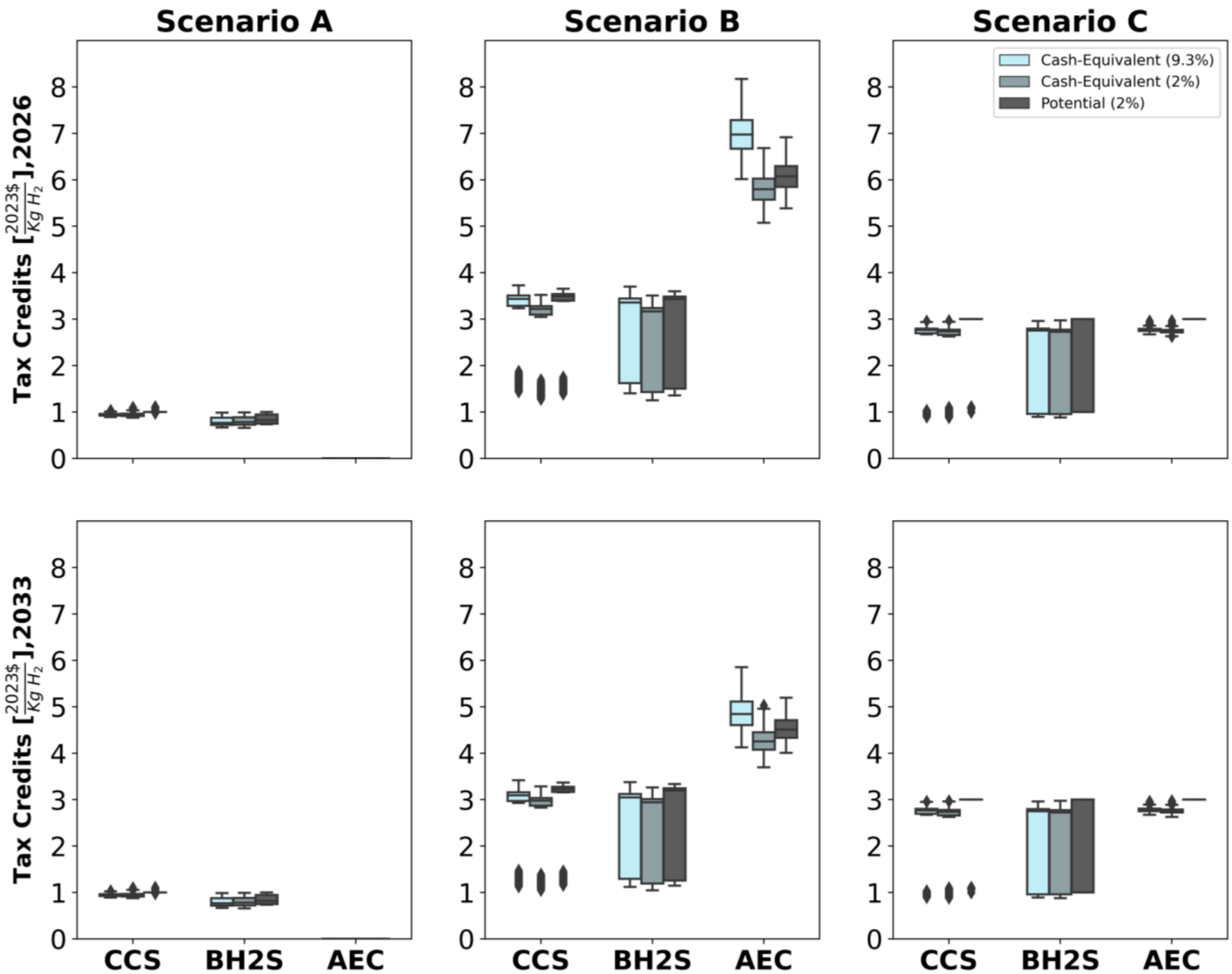

Figure 6 Hydrogen levelized policy support for low-carbon AP technologies.
Notes: the percentages in the keys signify the discount rate utilized to derive the levelized policy support.

4.5. Sensitivity analysis 1: Impact of carbon border adjustment mechanism

CBAM will be fully operational by 2033 (European Commission, 2023), so we model this scenario exclusively for 2033. As the European AP SMR progresses towards increasingly cleaner operations (see SI E), AP SMR and AP AEC surpass the threshold and experience diminishing cash flows over time. Conversely, those below the threshold see cash flow increases (see §3.2.2.1). With the advent of a border carbon tax, AP CCS and AP BH2S fall below the threshold European AP CI and realize an enhancement in profitability by approximately \$13/MT of NH3 across all scenarios, given a CBAM certificate price uniformly ranging from \$35-100 per MT of CO_{2e} (see Figure 7).

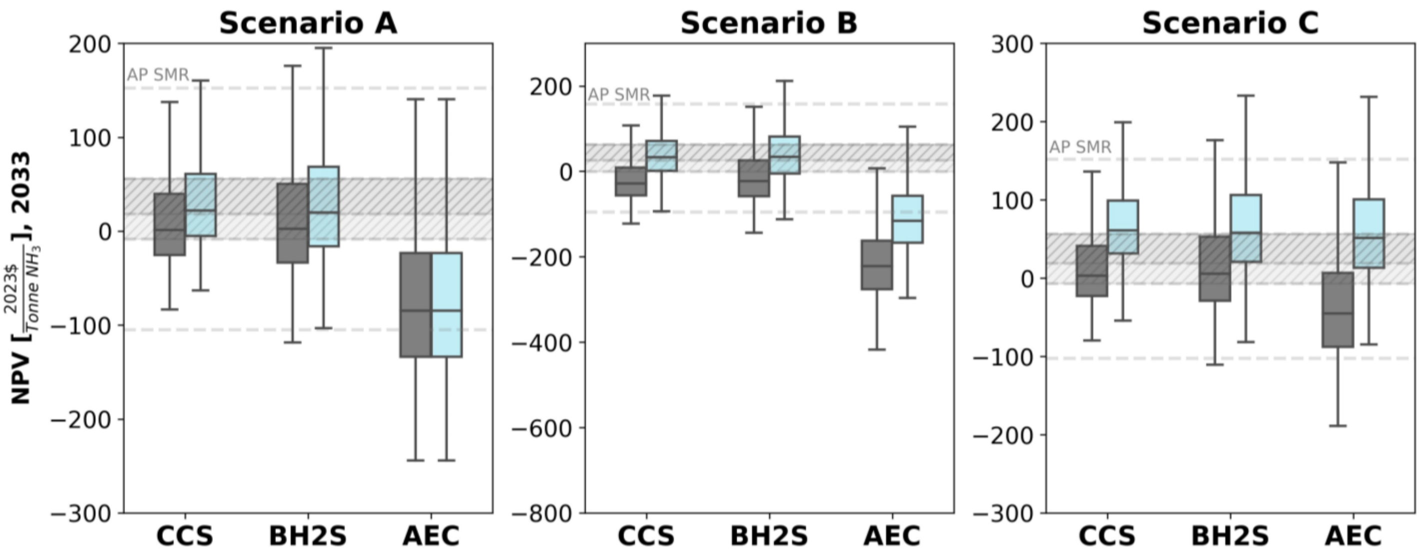

Figure 7 Impact of CBAM on NPV of AP technologies

Notes: The NPVs are benchmarked against a control scenario with no IRA policy and AP SMR.

As would be expected, when the CBAM is introduced, the AP SMR's economic performance is pushed down while the low-carbon technologies increase. The exception is AP AEC in scenarios A and B, which have higher emissions than the established cap. In the previous US-focused context, AP BH2S and AP CCS were not, on average, competitive with AP SMR without CBAM in scenarios A and B. With CBAM in place, the median performance of AP BH2S and AP CCS improves by 13 and 14$/MT, respectively, while the AP SMR's median performance diminishes by $3/tNH3. As expected, when targeting European exports under CBAM, AP BH2S and AP CCS are poised to be as profitable as AP SMR. AP CCS is $4/tNH3 above AP SMR, and AP BH2S is $1/tNH3 above AP SMR.

In scenario 2033C, the technologies were already on par with AP SMR without CBAM. Previously, the median performance of AP CCS and AP BH2S matched that of AP SMR. Now, the median of AP CCS and AP BH2S technologies occupy the 75th percentile of AP SMR ($58/MT), implying that AP SMR has only a 25% probability of matching or surpassing the median performance of AP CCS and AP BH2S.

In scenario A, AP AEC struggles to compete under the CBAM framework. It emits too much and incurs CBAM certificate costs rather than benefits. Scenario B accumulates excessive costs associated with upfront investment in the hybrid wind farm, exceeding the benefits from CBAM, hence still underperforming compared to all other AP options. Nonetheless, in scenario C, AP AEC surpasses AP SMR in performance because of the advantage of the PPA and CBAM support. In the baseline 2033C, AP AEC surpasses AP SMR by $13/tNH3. Under CBAM, this difference becomes $30/tNH3.

Inherent to this analysis is the assumption that the IRA mandates monthly renewable electricity and hydrogen production matching. Extensive discourse surrounds the impact of matching rules on green hydrogen deployment ((Cybulsky et al., 2023; “Green Hydrogen: An Assessment of near-Term Power Matching Requirements,” 2023; Ricks et al., 2023; Riley et al., 2023; Ruhnau & Schiele, 2023; Vargas et al., 2023). Yearly matching, while promoting green hydrogen deployment, comes at the cost of consequential emissions depending on power grid CI. Conversely, hourly matching would decelerate green hydrogen adoption while closely ensuring zero emissions. Therefore, in the following sensitivity analysis, we gauge the impact of yearly and hourly matching requirements on the performance of low-carbon AP options.

4.6. Sensitivity analysis 2: Cost of matching renewable generation with hydrogen production

It is worth noting that due to primarily inherent physical and technical limitations, the requirement of a steady-state/stable hydrogen production output profile still dominates industrial applications of end-use hydrogen such as i) ammonia (36%), methanol (15%), ii) hydrogen liquefication for transportation purposes, iii) hydrogen utilization in oil refining facilities to desulfurize oil (42%), iv) mining activities and also in v) steelmaking through the direct reduced iron (DRI) process (5%) (Barbir et al., 2016; Dincer & Ishaq, 2021; Genovese et al., 2023; Wijk, 2021)

In all the above industrial applications, modern sensor and feedback control technology is employed to ensure smooth dynamic reversion to the desirable design operating steady states in the presence of inevitable disturbances/shocks (system regulation) and also enforce smooth transitions under desirable time scales to new operating steady states (set point tracking) that may reflect new production (or other performance-related requirements) (Barbir et al., 2016; Dincer & Ishaq, 2021; Green & Southard, 2018).

However, in systems reliant on continuous hydrogen intake without hydrogen storage (i.e., ammonia, methanol, etc.), conventional control systems face limitations in adapting to the rapid variability of hydrogen input with the existing control system and equipment technology. While hydrogen production can fluctuate on a minute time scale, the Haber-Bosch process lacks such agility. The initiation of the Haber-Bosch (HB) system startup can span multiple days (Verleysen et al., 2023). Armijo and Philibert (2020) highlighted the HBS flexibility at 20% of the nominal hourly flow rate. Across the capacity factor datasets we study, we ascertain an hourly coefficient of variation ranging from 67% to 108%[19]. Given that green hydrogen production closely parallels electricity production on a minute scale, steady-state green hydrogen supply from VREs to the Haber-Bosch process is technically not feasible in the IRA timeframe.

In the ensuing section, we explore the implications of changing electricity-hydrogen matching rules while aligning with the Haber-Bosch process's steady-state requirements. Figure 8 presents the NPV of yearly matching and hourly matching. Table 6 presents the median NPV and CAC values across the three matching scenarios examined in this study. We also present the carbon abatement cost for yearly and hourly scenarios in Figure 9. We focus on AP AEC because it is the most sensitive technology to electricity by a large margin. The other technologies experience the same effects but to a lesser extent.

4.6.1. Yearly Matching

Replacing monthly constraints with yearly constraints yields positive outcomes for AEC. In 2026B, yearly matching AP AEC NPV outperforms monthly matching NPV by $289/tNH3.

[19] The locations mapped to the capacity factors correspond to the largest operational AP plants in the US. Some plants, like the complex in Donaldsonville – also the largest ammonia production complex in the world – has a low annual capacity factor of 18%. Other facilities, like the Woodward complex by CF Industries, have capacity factors upwards of 46% (Pfenninger & Staffell, 2016). We capture this variability in the upper and lower bound of the wind-farm and battery capacity input variables.

Furthermore, the gap between AP SMR and AP AEC shortens from $471/tNH3 (monthly matched) to $182/tNH3 (yearly matched) in scenario 2026B. Significant enhancements are also observed in AP AEC's NPV in 2033 scenario B (by $134/tNH3). The gap between AP AEC and AP SMR shrunk from $155/tNH3 to $38/tNH3 from monthly to yearly matching. The difference in NPV between yearly and monthly scenarios for scenario B, between 2026 and 2033, shrunk by 60% ($289/MT in 2023 to $117/MT in 2033). As renewable technology becomes more efficient and cheaper, the economic gain from relaxed matching shrinks considerably.

Table 6 Median NPV and CAC of electricity matching sensitivities.

Time	**2026**												*NPV increase and CAC decrease ↓*
Matching	**Yearly**				**Monthly**				**Hourly**				
Scenario	**B**		**C**		**B**		**C**		**B**		**C**		
Metric	**NPV**	**CAC**	**NPV**	**CAC**	**NPV**	**CAC**	**NPV**	**CAC**	**NPV**	**CAC**	**NPV**	**CAC**	
Reference (AP SMR)	32		32		32		32		32		32		
AP CCS	24	129	51	119	-21	140	51	119	-52	147	29	119	
AP BH2S	30	107	52	99	-10	114	52	99	-39	120	29	99	
AP AEC	-150	172	-2	114	-439	231	-2	114	-1889	550	-209	114	
Time	**2033**												
Matching	**Yearly**				**Monthly**				**Hourly**				
Scenario	**B**		**C**		**B**		**C**		**B**		**C**		
Metric	**NPV**	**CAC**	**NPV**	**CAC**	**NPV**	**CAC**	**NPV**	**CAC**	**NPV**	**CAC**	**NPV**	**CAC**	
Reference	22		22		22		22		22		22		
AP CCS	36	124	48	119	18	129	48	119	-14	138	38	119	
AP BH2S	35	103	44	99	19	106	44	99	-10	113	33	99	
AP AEC	-16	147	36	114	-133	172	36	114	-801	336	-60	114	
NPV decrease and CAC increase →													

Notes: Cells shaded in blue and gray are values that remain constant across time or scenario.

Under the monthly scenario and in the absence of batteries, the wind farm must be designed to ensure that there is sufficient energy supply for the AP plant even during the least efficient month of electricity production (typically in the summer; see SI D for more details). In the monthly matching scenario context, due to the cost differential between wind and battery technologies and wind resource availability (see section D), our optimization reveals that the most cost-effective solution is oversizing the wind farm without a battery.

Conversely, under a yearly matching scenario, the wind plant's objective is to generate sufficient renewable energy over a year to meet the energy requirements of the AP plant. When the wind farm falls short of producing the necessary electricity, the AP plant draws power from the grid, resulting in CO_2 emissions (which depend on the grid's CI; see Ricks et al. 2023 for a discussion of this issue). Conversely, the excess clean energy could neutralize the CO_2 emissions during wind farm surpluses.[20] However, this assessment does not encompass the potential consequential emissions arising from the need for additional dispatchable (most likely fossil-based) power to meet the increased power demand of the AP plant. This observation

[20] The extent of this neutralization depends on actual grid condtions which varies from one location to another and from one hour to another. We did not attempt to model this issue at this level of precision so leave this for future research

aligns with the conclusions drawn by Ricks et al. (2023) and other relevant studies (Cybulsky et al., 2023; "Green Hydrogen: An Assessment of near-Term Power Matching Requirements," 2023; Vargas et al., 2023).

In scenario C, the performance between yearly and monthly matching is the same because there is no battery storage. When there are no batteries, the only difference between yearly and monthly matching is the wind farm's capacity. The PPA price is indifferent to scale (capacity) and equal across these matching cases ($46.2/MWh) (see SI D for more details).

In scenario B, the significant shortening of the matching gap is due to the compounding effects of both technology cost reductions and increasing wind farm capacity factors. As wind turbine hub height increases (in our study, 90m in 2023 to 120m in 2030), so is the average capacity factor, reducing the required wind design capacity by 16% (Observatory of Economic Complexity, 2023; Pfenninger & Staffell, 2016). Similarly, the cost per nameplate capacity decreases by 2033, resulting in non-linear cost reductions.

4.6.1. Hourly Matching

The median difference in AP AEC NPV across yearly and hourly matching is massive $1739/MT and $207/MT for scenarios B and C, respectively, in 2026. In 2033, the gap decreases to -$785/MT in scenario B and -$96/MT in scenario C. The economic costs of ensuring hourly matching are non-linear. The gap across seven years is decreasing by 54.9% and 54.6% in scenarios B and C due to technological improvements and cost reductions of the AEC stack and hybrid wind farm. However, by 2033, the gap will not shrink enough to make AP AEC viable. Even in a case of outstanding performance (75th percentile NPV) in 2033, AP AEC lags behind AP SMR by $659/MT in case B and 206/MT in case C. Hence, we see that a build-and-own scenario is never viable while a PPA contract AP AEC may outperform AP SMR slightly in less than 25% of simulations – which are characterized by high technology cost reductions, high ammonia prices, and high wind capacity factors.

The problem we describe in hourly matching is designing a hybrid wind farm to be resilient to long-lasting periods of low capacity while simultaneously maintaining emissions from the grid to a minimum. This problem has been investigated to assess the performance of Power-to-Ammonia plants in the context of a feasibility analysis by Verleysen et al., 2023. The most general form of the problem arises when recognizing the capacity factor as a stochastic function. Engineers can design renewable variable electricity generation and hydrogen production matching resilience for a given probability of consecutive hours with minimal electric generation. With more resilience, the facility's nameplate capacity becomes more significant to withstand prolonged periods of low electricity generation.[21]

The concept of resiliency serves as a representation of the matching constraint. Over a 40-year plant lifespan, achieving a fully resilient design on a yearly matching basis involves selecting the poorest-performing year from the 40-year duration (assuming perfect foresight)

[21] We assume 2019 capacity factors for all years of our analysis. The deterministic capacity factor allowed us to make this problem tractable across 40 years – especially for hourly matching. Therefore, it is likely our results are an underestimation of hourly matching costs because the design of the wind farm and battery system should be envisioned to be robust to extreme scenarios across the 40-year lifespan.

and designing the system accordingly. This approach guarantees zero carbon emissions on a yearly matching basis[22].

Now, envision extending this statistical exercise to the hourly timescale, which involves a staggering 350,400 hours. Given that the minimum value is likely to be near zero[23], and in the case of wind-only setups, the optimal scale would tend toward infinity, necessitating battery integration to prevent this outcome. Consequently, one can infer that the sizing of an hourly matched wind farm should be notably larger than its yearly matched counterpart to deliver an equivalent amount of firm power.

4.6.2. Hydrogen deployment and IRA implications of an hourly matched world

Given that most of the hydrogen production serves established fossil-fuel-based chemical plants (e.g., those producing ammonia, methanol, hydrogen peroxide, etc.)—which have (i) vertically integrated fossil-fuel hydrogen production and (ii) cannot accommodate hydrogen fluctuations (Armijo, J., & Philibert, 2020)—it is improbable that AEC will achieve significant market penetration in the near term, especially under the hourly matching requirement[24].

In scenario B, the 48E credits directly influence the CAC, whereas in scenario C, these credits are implicitly factored into the PPA. As a result, the most representative CAC for the low-carbon technologies producing ammonia is that shown in scenario B. This approach mirrors the accounting methods used for carbon emissions via the LCA. In scenario B, the policy support is comprehensively incorporated. In contrast, in scenario C, the credits achieved by the wind farm are not considered part of CAC computations (subsidies for the hybrid wind farm in C are not part of CAC calculations for low-carbon ammonia). We highlight this distinction as we aim to identify a technology that (a) competes with AP SMR and (b) realizes such an economic outcome while minimally utilizing public funds.

Under the outlined criteria, by 2033, the current AP AEC technology is less likely to attract investment when other low-carbon alternatives, such as AP CCS and AP BH2S, are on the table. AP CCS stands out as the most viable option for investors. Its economic performance aligns closely with AP SMR and AP BH2S, but it circumvents the market risks inherent to AP BH2S. AP CCS naturally offers a hedge against decrements in ammonia prices and spikes in natural gas costs. Although the median CAC of AP CCS is 22% greater than that of AP BH2S, it remains a cost-effective avenue for public funds to cut emissions substantially. When set side by side, AP AEC does not come close to the NPV of either AP CCS or AP BH2S. Its median CAC stands higher at a median of 257% and 80% of the social cost of carbon for hourly and yearly matching in 2026, respectively, while AP CCS and AP BH2S only stand at a median of 68-56% and 60-49% for hourly and yearly matching[25]. In a scenario where matching occurs annually, 2033C AP AEC has the potential to economically compete with AP BH2S and AP

[22] In this study we assume the capacity factor for each year is constant and equal to the hourly capacity factors of the 2019 data we use to size the hybrid wind farm (see section D) (Pfenninger & Staffell, 2016).

[23] Across all capacity factor datasets, 15.7% of hourly data points are below 0.05 capacity factor. 5.8% of data points are below 0.01 capacity factor.

[24] We acknowledge that one of the limitations of our study is that we exclude solar and hydrogen storage. These technology alternatives may bridge the gap between AP AEC and AP SMR. However, the degree to which hydrogen storage or solar helps bridge the gap depends on the cost. PVs are as costly as wind and are less efficient and hydrogen storage is known to be relatively expensive as well. We leave this question for future research.

[25] Bearing in mind our consistent use of a 2% discount rate for the social cost of carbon.

CCS albeit at a higher abatement cost ($147/tCO2 for AP AEC while AP BH2S and AP CCS are at $107/tCO2 and $129/tCO2, respectively)[26].

Given these findings, there are essential insights that policymakers must consider. Should the primary aim be carbon emissions reduction cost-effectively, then it is a no-regret policy to sustain and possibly enhance support for AP CCS and AP BH2S until AP AEC can bridge the technological gap — whether this comes from direct advancements in electrolyzer technology or through peripheral benefits stemming from the maturation of wind farms and batteries or when the US power grid becomes (near) zero carbon. During this period, enforcing monthly matching and gradually transitioning to hourly matching would be a strategic approach – similar to the European approach, allowing monthly matching until 2030 (COMMISSION DELEGATED REGULATION (EU) 2023/1184, 2023). While it will always be true that yearly matching will be better than hourly matching due to the statistical problem we described, if wind technology can reach sufficiently high capacity factors, then the hourly matched scenario may be competitive with AP SMR.

Conversely, should deployment and cost reduction of AEC technology be the prime policy objective, even if it exceeds the current social cost of carbon and potentially a much higher near-term increase in emissions, then an immediate implementation of yearly matching seems sensible.

4.6.2.1. Limitations of assuming an inflexible steady state[27]

The assumption of a steady-state operation for the Haber-Bosch (HB) loop in our study reflects a conventional HB unit, which imposes significant costs on the associated hybrid wind farm system, especially for the AEC option. A survey of industry opinions indicates that conventional HB systems may typically operate with a 20%/h flexibility. However, the operable capacity range remains uncertain, spanning from 10% to 90% of nominal capacities in the literature (Verleysen et al., 2023; C. Wang et al., 2023). In contrast, Topsoe is advancing pilot projects that aim for 10% to 100% operational flexibility, although these are in the early stages and have not yet been cost-optimized (K. Rouwenhorst, 2023).

Our analysis shows a significant net value gain if HB flexibility could ease the load on hybrid wind systems to meet monthly instead of hourly matching rule; however, this technology is not yet commercialized. Thus, we consider flexible HB to be at early demonstration stage and will unlikely deploy at large commercial scale by the end of the IRA policy framework (2033).

[26] We compare the CAC of scenario B only because scenario B's CAC encompasses the total policy support for the entire system (AP and hybrid wind farm). Scenario C only accounts for the AP plant.

[27] We provide an in-depth literature review on this topic in SI F.

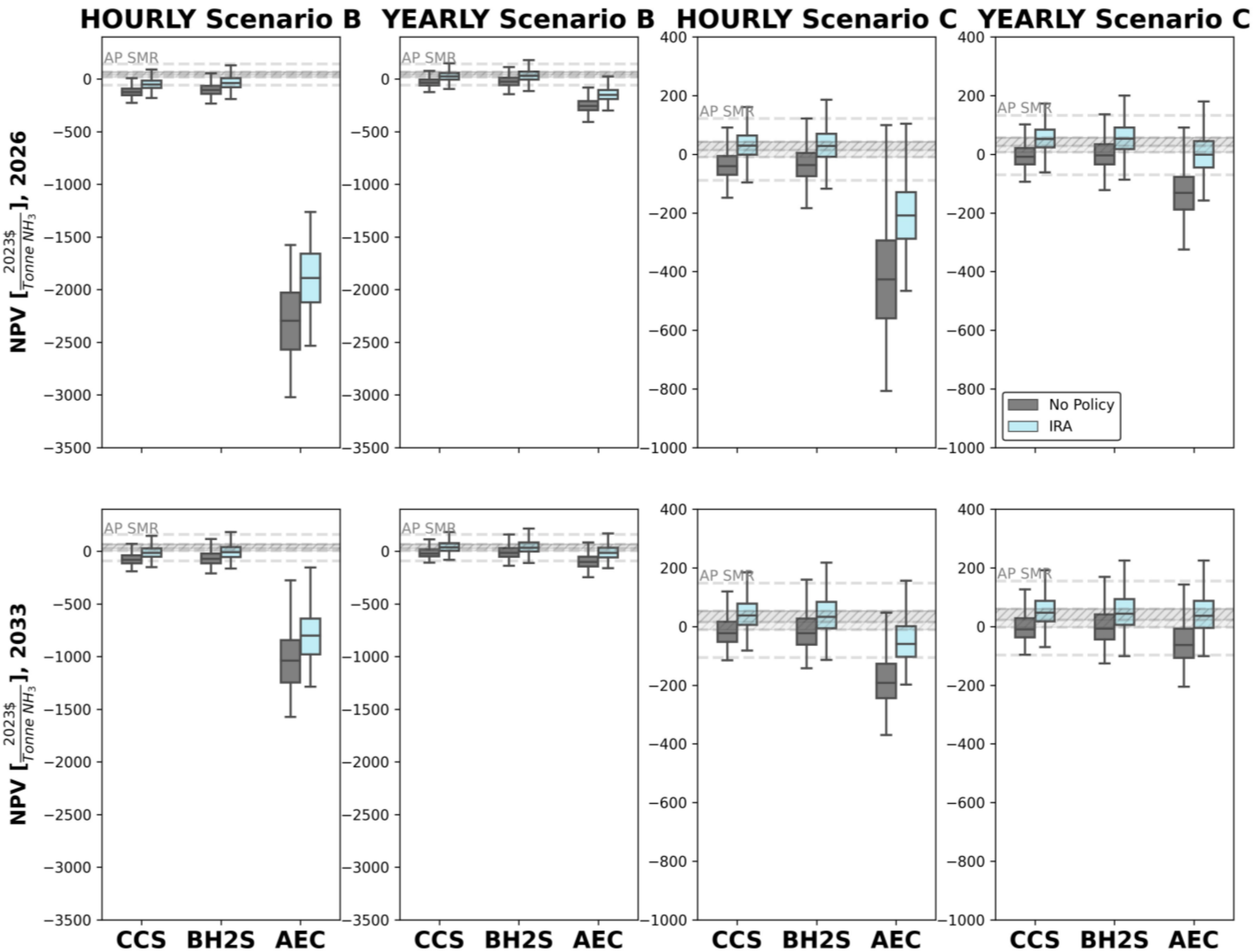

Figure 8 NPV of low-carbon AP technologies: hourly and yearly matching scenarios

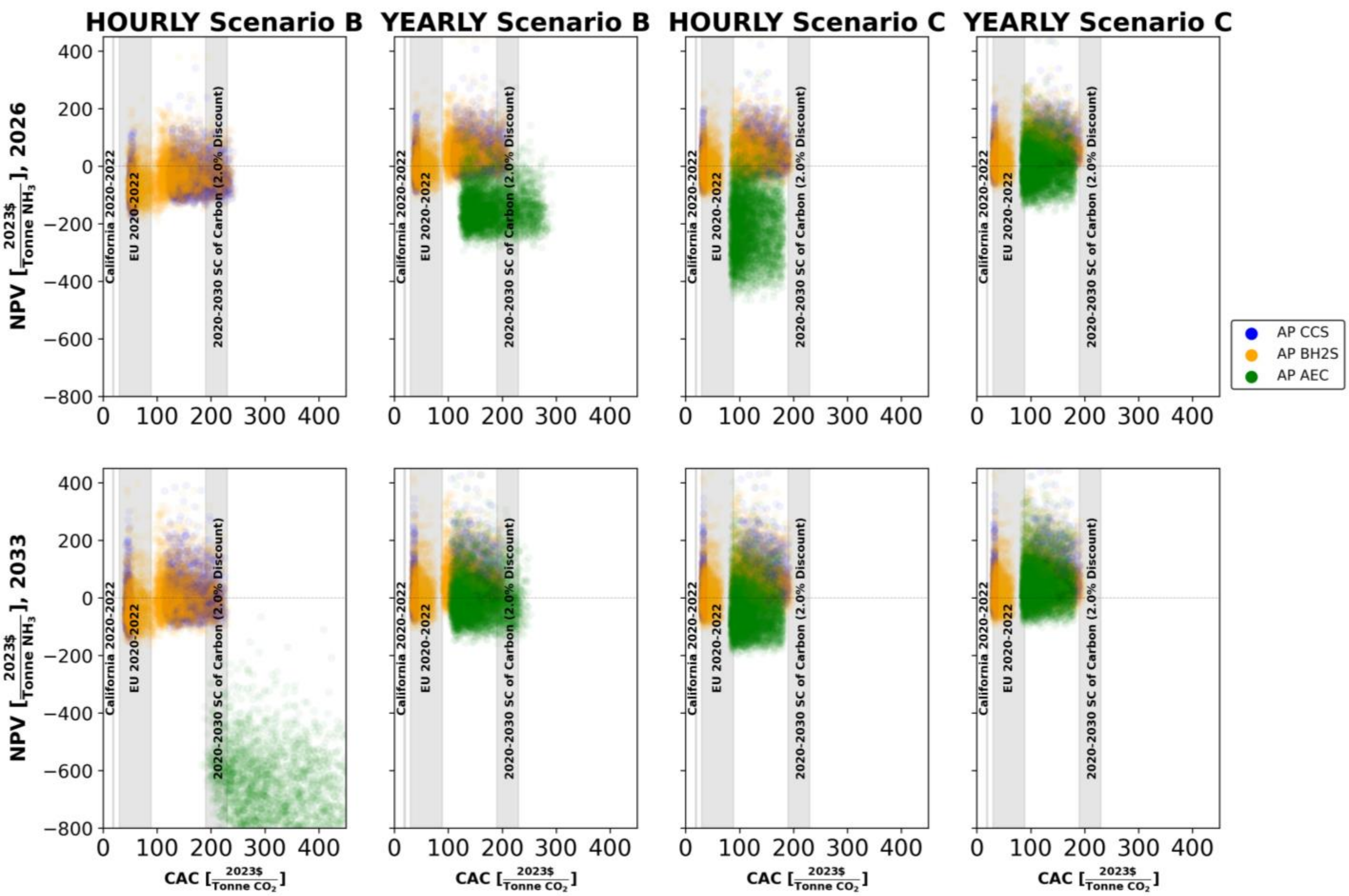

Figure 9 NPV versus carbon abatement cost: hourly and yearly matching scenarios

5. Conclusions and Policy Implications

The existing studies either focused on LCAP's techno-economic analysis or on policy support for low-carbon hydrogen (see SI §F). Building on our stochastic economic analysis of the plant-level AP model, this study comprehensively considers key LCAP pathways under multiple policy frameworks – subsidies (IRA tax credit programs and transaction costs of the US tax credit market), carbon pricing policies (EU ETS and CBAM), and hydrogen production rules (renewable electricity and hydrogen production matching rules). Our detailed modeling findings imply the following conclusions.

CCS and BH2S are competitive against SMR under the IRA policy framework and perform on par. CCS option has a natural market hedge as ammonia prices are highly correlated with natural gas prices. BH2S has a higher market risk profile than CCS because ammonia price is uncorrelated with bioenergy cost (See SI §G). Further, given its dependence on relatively cheap biomass feedstock, BH2S's competitiveness is limited by feedstock supply costs and constraints. Similarly, CCS economics depend on the performance of its downstream value chain – CO2 transport and storage. Risks (or perception) of CO2 leakage could negatively impact IRA's cash-equivalent support, influencing both investment decisions and the rate of CCS technology adoption.

AEC has the lowest rate of return among the competing LCAP technologies and is not competitive (against SMR) in the near term despite potentially receiving the highest public support. Under IRA, AEC's economics depends on access to a well-developed, cheap, renewable PPA market with 24/7 clean energy matching, which is still under development and costly (Hausman & Bird, 2023; Jain, 2022; Miller, 2020). CCS and BH2S also depend on the PPA market, but their economics are less sensitive to the matching requirements.

Our findings show that between 2026 and 2033, there is a noticeable improvement in AEC's economics due to technology improvements and cost reductions. However, these cost reductions depend on investor participation in early deployment to drive these costs down. If the policy concerns early AEC deployment to drive costs down, IRA subsidies may need to be increased to account for these dynamics (i.e., the $3/kgH2 tranche increased to $4.8/kg)[28]. While public attention was focused on the trade-off between the stringency of carbon accounting of the AEC pathway and its early deployment, irrespective of these cost reductions, AEC still underperforms relative to CCS and BH2S in the IRA policy timeline. Thus, technology neutrality in designing policy support for low-carbon technologies is essential, while the focus should be on stimulating innovation in low-carbon hydrogen technologies and, crucially, their supply chains and market organizations, such as the 24/7 clean PPA market.

The IRA provides unprecedented support for AEC, but the technology underperforms from private and public perspectives: its NPV is lower than those of CCS and BH2S, while its CAC, in most cases, exceeds the social cost of carbon and that of CCS and BH2S. Although marginally exceeding the recent EU carbon prices, IRA subsidy programs are cost-effective in terms of value for public money in supporting hydrogen-based climate mitigation technologies.

It is essential to consider nuances of the US tax credit markets because tax credits under the IRA will not translate into actual subsidies on a parity level. Thus, the levelized cost approach should explicitly consider these transaction costs. Ignoring the complexity of the tax credit market and its interactions with the PPA markets will result in an underestimation of LCAP levelized cost, especially those with significant barriers to deployment and demonstrate their efficiency at scale (Abolhosseini & Heshmati, 2014; Barradale, 2010; Kahn, 1996). Risky and unproven (at scale) technologies (AEC has the highest risk profile[29]) will involve higher capital costs and verification, compliance, and monitoring costs, potentially significantly increasing transaction costs beyond what this study assumes. Technologies with high-risk profiles will be costlier for the government to support, implying that the government may consider underwriting risks to lower capital costs for investors and, hence, lower support costs per unit of H_2 (e.g., by 12-17% for AEC if its WACC is reduced from 9% to 2%).

In the foreseeable future, there is little chance of putting a price on carbon emissions in the US. Instead, the IRA framework offers unprecedented financial incentives to stimulate private capital into low-carbon energy technologies. On the contrary, the EU's flagship carbon pricing is regarded as the first-best economic policy to tackle carbon emissions (Bennear & Stavins, 2007; Nordhaus, 1992; "The Stern Review on the Economic Effects of Climate Change," 2006). Perhaps not by design, the interactions between the CBAM and IRA will likely mean much stronger incentives to decarbonize US AP than standalone IRA. The relatively small carbon taxing and the opportunity to trade CBAM certificates could substantially increase the relative economics of US-based LCAP: grid connection (Scenario A) is now a cost-effective option for at least CCS and BH2S. Under CBAM and IRA, the CAC to decarbonize US AP via CCS and BH2S could be much lower, falling in the range of recent EU carbon prices (Scenario A). This finding reconfirms the potential effectiveness of multiple policy instruments in a "second-best" world (Bennear & Stavins, 2007; Lehmann, 2012; Sorrell, 2003) to reduce the US AP carbon emissions.

There is considerable debate about consequential emissions from renewable electricity and hydrogen production matching rules. Starting from the monthly matching rule will not unduly penalize AEC's economics while ensuring lower consequential emissions than the yearly rule.

[28] This value was calculated by increasing the highest tranche of 45V credits ($3/kg) until 2026C AP AEC's NPV matches 2033C AP AEC's NPV.

[29] Measured as coefficient of variations (CV) of its NPV compared to CV of other LCAP.

While the hourly matching rule ensures limited consequential emissions from the AEC, its unfavorable economics will unlikely stimulate private investment. Hourly-matched AEC pathway seems unlikely a worthwhile avenue to pursue from the public policy perspective because its support cost outweighs the carbon savings benefits (in most cases, AEC's CAC is substantially higher than the social cost of carbon).

AP is expected to almost triple (688 Mt/year) by 2050, with 83% from renewable ammonia (IRENA, 2022). If renewable ammonia is part of this vision, then advancements in the flexibility of the HB process are a crucial avenue for research and development. Some research has highlighted the challenges of flexible HB[30]. The literature reports HB may handle wide ranges of output (5-80% of capacity) and ramping rates (20% capacity/hour) based on feasibility studies and industry opinion (Armijo & Philibert, 2020; Lazouski et al., 2022; Verleysen et al., 2023). However, the demonstration of flexible HB at a small scale is only starting, while the additional costs of flexible HB loops at a commercial scale are unclear (Rouwenhorst, 2023; Davenne et al., 2022). Given the current industry state versus the optimistic techno-economic literature, it may be a reality that flexible HB may exist commercially in the next ten years but beyond the IRA timeline. Nevertheless, the incentives for making flexible HB are clear under an electric grid with increasingly fluctuating renewables: our results highlight that the economic benefit of flexible HB could be substantial: \$3.4-7.4 bn or \$96-207/tNH3[31].

Overall, this research finds that to decarbonize the AP there are key areas for policymakers and the academic community to focus on in the next decade: (i) adapting HB to variable bioenergy quality and process efficiency while ensuring feedstock's sustainability and availability, (ii) ensuring safe transport and permanent storage of CO2 while de-risking CCS value chain, (iii) supporting research and development to drive down cost and efficiency improvements of flexible HB, renewable energy, and electrical and hydrogen-based storage, (iv) policy support framework should ensure technology neutrality and competition while recognizing the nature of "dynamic" technology cost reduction (Gillingham & Stock, 2018) and interactions between policy instruments and between technologies.

[30] We include an in-depth literature review on flexible HB in SI §F.
[31] Or 25-50% of the levelized cost of grey ammonia in 2020 (IEA, 2021)

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