

Article

Selection of P2X Technical Routes for Integrated Energy Production Units Based on Technical and Economic Analysis

Yuqing Wang¹, Qian Liu¹, Jiayi Yu¹, Min Tang¹ and Yani Yang^{2,*}

¹ Department of Economic Management, North China Electric Power University, Baoding 071000, China; wangyuqingncepu@foxmail.com (Y.W.); qianliu@ncepu.edu.cn (Q.L.); jiayiyu@ncepu.edu.cn (J.Y.); mintang@ncepu.edu.cn (M.T.)

² Qionghai Power Supply Bureau, Hainan Electric Power Co., Ltd., Qionghai 571442, China

* Correspondence: yangyani8@hn.csg.cn

Abstract

In pursuit of energy decarbonization and supply security, the integrated energy production unit (IEPU) is regarded as a notable multi-technology energy production model integrating coal-fired power, carbon capture, and renewable energy. As a core component of the IEPU, Power-to-X (P2X) technology encompasses various technical routes with distinct economic performance and technological maturity at different development stages. Thus, selecting the most techno-economically optimal route is critical. In view of this, this paper proposes an integrated decision-making framework for the selection of P2X technology routes in IEPU, which combines “technology selection—economic analysis—risk assessment”. Firstly, a decision model for key P2X processes is established, with the levelized cost of hydrogen and unit hydrogen conversion revenue as core performance metrics to identify the optimal technology combination for hydrogen production and utilization. Secondly, integrating the aforementioned optimized technical route, a life-cycle economic benefit evaluation model is constructed for IEPU retrofit projects to systematically assess the overall economic feasibility of the IEPU project. Thirdly, an investment risk assessment model for P2X-integrated IEPU retrofits is established based on interval number theory, which can quantify project risks under fluctuations of critical parameters such as electricity and carbon prices. Finally, a case study of a 600 MW coal-fired unit retrofit demonstrates that “alkaline electrolysis + methane synthesis” constitutes the optimal P2X technology combination. However, its profitability is relatively sensitive to fluctuations in external market parameters, necessitating the implementation of corresponding risk management strategies.

Keywords: integrated energy production unit; Power-to-X; techno-economic analysis; selection of technology route



Academic Editor: Massimo Caruso

Received: 2 February 2026

Revised: 12 March 2026

Accepted: 17 March 2026

Published: 20 March 2026

Copyright: © 2026 by the authors.

Licensee MDPI, Basel, Switzerland.

This article is an open access article distributed under the terms and conditions of the [Creative Commons Attribution \(CC BY\)](https://creativecommons.org/licenses/by/4.0/) license.

1. Introduction

Under the goals of carbon peak and neutrality, the priority for the power generation sectors is to advance the low-carbon transition of conventional coal-fired power generation and to enhance the efficient utilization of renewable energy [1,2]. In this context, the integrated energy production unit (IEPU) is a multi-energy production unit that is based upon carbon capture retrofit for thermal power units. It integrates technologies such as renewable-based water electrolysis and green fuels synthesis. And IEPU presents a viable solution for achieving high-efficiency energy utilization, facilitating low-carbon transition,

and ensuring energy security and stable supply [3–5]. As a crucial component of IEPU, Power-to-X (P2X) technologies significantly influence the overall operational efficiency and revenue model of IEPU systems due to their varying levels of technological maturity, economic viability, and operational flexibility [6]. Therefore, the systematic evaluation and selection of the optimal P2X technical combination have become urgent issues in the decision-making of the IEPU retrofit project.

At present, scholars have conducted a series of studies on the structural design and economic assessment of IEPU systems. The reference [7] proposed the basic structure of IEPU, integrating carbon capture systems in thermal power units, renewable energy-based water electrolysis for hydrogen production, and methanol synthesis equipment into a unified system. Through coordinated operation of internal subsystems and flexible interaction with external power grids, the system can produce and store multiple types of energy and further synthesize green fuels. References [8,9] pointed out that the IEPU with green methanol as the product has significant carbon emission reduction potential, and the carbon trading market can provide economic impetus for IEPU development. References [10–12] identified carbon capture and utilization (CCU), electrolytic hydrogen production, and hydrogen utilization as the core production processes of IEPU. In the section of CCU, reference [13] indicates that post-combustion capture is the most mature and widely adopted, particularly applicable to the retrofit of existing power plants. Reference [14] analyzed the investment threshold and transformation route for coal-fired unit CCU under the carbon trading mechanism. For electrolytic hydrogen production, the three most prevalent methods include alkaline water electrolysis (AWE), proton exchange membrane (PEM), and solid oxide electrolyzer cell (SOEC). Among these, the AWE technique was formulated for analysis in reference [15] and compared with the PEM technique in references [16–18]. References [19–21] compared these technologies from the perspectives of energy efficiency and energy consumption. Reference [22] focused on the economic differences among AWE, PEM, and SOEC technologies, analyzing the combined impact of electricity prices and key equipment investment on hydrogen production costs. Reference [23] further systematically compared the application of AWE, SOEC, and AEM technologies in power-to-gas from the perspective of thermal economy. Reference [24] evaluated the environmental impact of four mainstream electrolyzer technologies from a life-cycle perspective, providing a systematic basis for the sustainability assessment of electrolytic hydrogen production technologies. However, few studies have systematically compared the applicability boundaries and economic differences among the three mainstream technological pathways: AWE, PEM, and SOEC. In the hydrogen utilization stage, reference [25] conducted an energy analysis of different methanol synthesis methods and compared the economic feasibility of different synthesis devices. Reference [26] constructed an IEPU system including both power-to-methane and power-to-methanol, analyzing the impact of electrolyzer investment costs and product market prices on system economics. Reference [27] examined the comprehensive performance of hydrogen-to-methane conversion and liquid fuels such as methanol across multiple dimensions, including technical, economic, environmental, and political aspects. Reference [28] optimized hydrogen production and consumption, with particular focus on the utilization pathways of hydrogen conversion into methanol and ammonia. References [15,28] achieved the on-site conversion of hydrogen into ammonia and methanol within the same system. These studies lay the foundation for understanding the economics of specific technologies but suffer from two common limitations. (1) Most are limited to comparing the technologies in a single step of P2X, lacking a comprehensive economic evaluation of the entire technical route coupling hydrogen production and utilization at the system level; (2) Existing economic analyses are mostly based on certain parameter

assumptions and fail to fully consider the inherent uncertainty of key economic parameters within the entire life-cycle of the project.

In view of this, this paper proposes a structured approach for optimal P2X technology route selection in IEPU projects. Firstly, an economic decision-making model for the “electrolysis-utilization” dual-stage of P2X technology is constructed to enable horizontal comparability among different technology combinations. Secondly, a life-cycle economic benefit evaluation model is established to verify the overall economic viability of the project. Thirdly, an investment risk assessment model is based on interval number theory to quantify investment risks induced by uncertain factors. Finally, a 600 MW coal-fired unit retrofit into an IEPU is used as an empirical case to validate the effectiveness of the proposed research framework and models and to identify the optimal technology route. A detailed summary highlighting the main features of the studied literature and the novelty of the present work is shown in Table 1.

Table 1. Summary of the related literature.

Reference	Electrolytic Hydrogen Production			Hydrogen Utilization			Economic Assessment	Risk Assessment
	AWE	PEM	SOEC	Methane Synthesis	Methanol Synthesis	Green Ammonia Production		
[7]	×	×	×	✓	×	×	✓	×
[8]	×	✓	×	×	✓	×	✓	×
[15]	✓	×	×	×	✓	✓	✓	×
[16]	✓	✓	✓	✓	✓	✓	✓	×
[17]	✓	✓	✓	✓	✓	✓	×	×
[18]	✓	×	×	×	✓	✓	✓	×
[19]	✓	✓	×	✓	✓	×	✓	×
[20]	✓	✓	×	×	×	×	×	×
[21]	✓	✓	×	×	×	×	×	×
[22]	✓	✓	✓	×	×	×	✓	×
[24]	✓	✓	✓	✓	✓	✓	×	×
[25]	✓	✓	✓	×	✓	×	✓	✓
[26]	✓	×	×	✓	✓	×	✓	×
[27]	✓	×	×	✓	✓	×	✓	×
[28]	×	×	×	✓	×	×	✓	×
Proposed model	✓	✓	✓	✓	✓	✓	✓	✓

Compared with previous studies, the main novelties of this paper are highlighted as follows.

- (1) An investment decision-making analysis framework for the P2X technology route of the IEPU project is proposed, covering “technology selection—economic analysis—risk assessment”. The technology selection, full life-cycle economic assessment, and uncertainty risk management are integrated into a unified analysis system, providing a complete decision support path from technical feasibility to investment stability for the IEPU retrofit project.
- (2) An economic evaluation method suitable for the “electrolysis—utilization” dual links of P2X technology is proposed. By establishing two core indicators, namely the levelized cost of hydrogen and the unit hydrogen conversion revenue, a systematic economic comparison of the P2X technology route is achieved.
- (3) The interval number theory is introduced to establish an investment risk assessment model for IEPU retrofit projects. This model expanded the key parameters, such as electricity price and product price, from single definite values to internal representations. Through indicators such as interval net present value (I-NPV) and interval internal rate of return (I-IRR), the potential fluctuation range of project economic benefits is quantified.

The subsequent structure of this paper is organized as follows: Section 2 elaborates on the system structure and technical route decision-making framework of IEPU; Section 3 constructs the decision-making model of the key processes of P2X technology; Section 4

establishes the full life-cycle economic effect assessment model for IEPU retrofit projects; Section 5 proposes an investment risk assessment model based on interval numbers; Section 6 describes the case study and comparative analysis of results; Section 7 concludes the study.

2. System Structure and Technical Route Decision-Making Framework of IEPU

2.1. System Structure of IEPU

The IEPU integrates coal-fired plants, renewable energy systems, electrolytic hydrogen production systems, carbon capture, utilization, and storage (CCUS) units, hydrogen storage tanks, and hydrogen utilization units. Surplus renewable energy powers electrolyzers and hydrogen utilization units. The hydrogen produced by electrolysis units reacts with CO₂ obtained from the carbon capture to produce green fuels like methane, methanol, and green ammonia [29,30]. The system structure is shown in Figure 1.

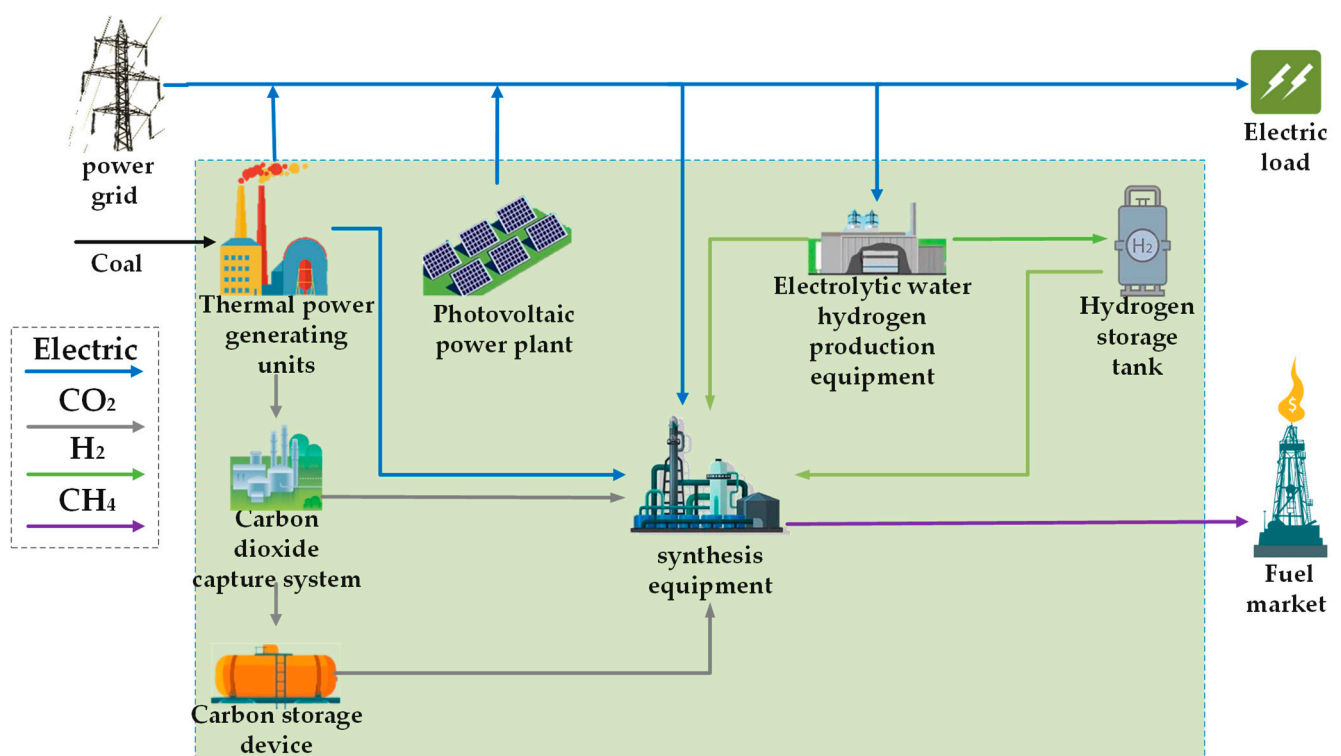


Figure 1. System structure of integrated energy production unit.

To optimize and upgrade existing energy production units, the retrofitted IEPU project leverages carbon capture techniques at conventional coal-fired plants to separate and purify CO₂ emissions. Simultaneously, by integrating photovoltaic power generation into the retrofitting, water electrolysis can harness renewable energy to produce clean hydrogen. Through CO₂ hydrogenation, the system generates carbon-neutral synthetic fuels, like methane, methanol, and ammonia, reducing the carbon footprint and closing the carbon cycle.

2.2. Key Technical Route for IEPU

As shown in Figure 2, P2X technology, comprising electrolytic hydrogen production and hydrogen utilization, plays a critical role in IEPU technical routes.

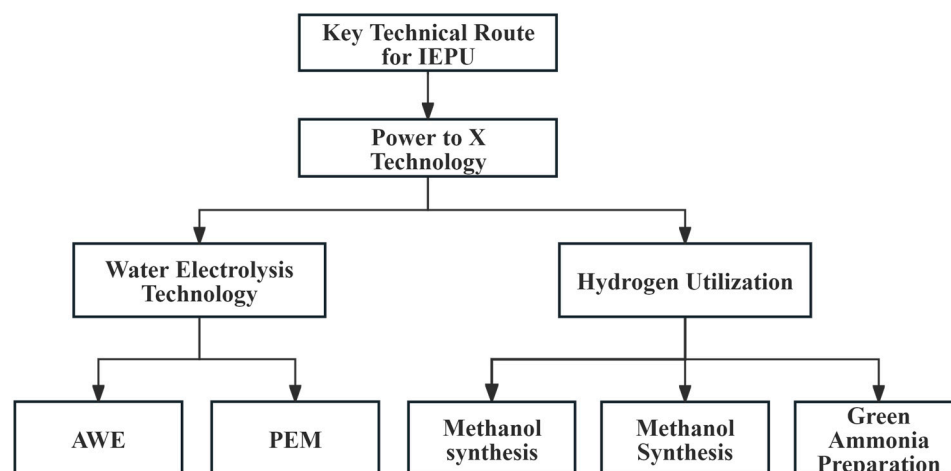


Figure 2. Key technology roadmap for integrated energy production units.

2.2.1. Technology Routes for Electrolytic Hydrogen Production

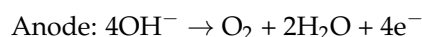
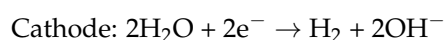
The primary technologies are AWE, PEM, and SOEC. A comparative analysis of their parameters and features is presented in Table 2.

Table 2. Comparison of electrolysis techniques.

Electrolysis Technology Type	AWE	PEM	SOEC
Electrolyte	KOH	PEM	YSZ
Temperature range (°C)	70–90	50–80	500–1000
Operating pressure (MPa)	<3	<7	0.1
Electrolysis efficiency (%)	60–75	70–90	85–100
Startup time (min)	>20	<10	<60
Commercial characteristics	Mature, high commercialization, low investment	Small-scale domestic application, high investment	In the laboratory research and development stage, not yet industrialized

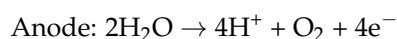
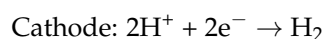
(1) Alkaline Water Electrolysis Technique

AWE typically employs KOH or NaOH as the electrolyte. Water dissociates at the cathode into H^+ and OH^- . H^+ get electrons at the cathode to form H_2 , while OH^- migrates across the diaphragm, loses electrons, and recombines to form water and oxygen at the anode. Reactions occurring on the electrodes of AWE can be summarized as follows:



(2) Proton Exchange Membrane Electrolysis Technique

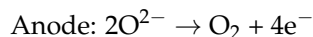
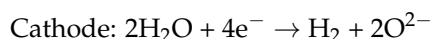
A PEM electrolyzer comprises electrodes and a proton exchange membrane, using pure water as the electrolyte. At the anode, H_2O is oxidized to generate H^+ and O_2 . During this phase, the H^+ migrates across the membrane to the cathode, combining to form H_2 . Reactions of the whole procedure in PEM can be written as:



(3) Solid Oxide Electrolysis Technology

The SOEC electrolyzer utilizes a ceramic material as the electrolyte, offering a highly efficient process for low-cost hydrogen production. At the cathode, H_2O is reduced to

generate H_2 . The O^{2-} formed at the cathode migrates through the solid electrolyte toward the anode, where it recombines to form O_2 , thereby completing the electrical circuit with the release of electrons. The partial reactions involved in this process are as follows:



2.2.2. Technology Routes for Hydrogen Utilization

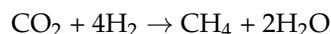
The hydrogen utilization technologies involve coupling hydrogen generated via water electrolysis with downstream chemical processes to yield target green fuels or chemical products. Hydrogen conversion is achieved primarily through three routes: methane synthesis, methanol synthesis, and green ammonia synthesis. An energy efficiency analysis is presented in Table 3.

Table 3. Energy efficiency comparison of hydrogen utilization technologies.

Indicator	Methane Synthesis	Methanol Synthesis	Green Ammonia Production
Raw materials	CO_2, H_2	CO_2, H_2	N_2, H_2
Conversion efficiency (%)	81.9	85.1	67
Unit energy consumption (kWh/kg)	28.1	14	12
Comprehensive energy efficiency (%)	49.5	51.8	43

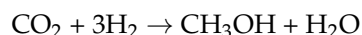
(1) Methane Synthesis

This process involves reacting the produced hydrogen with carbon dioxide captured from fossil-fuel power plants to produce methane (synthetic natural gas). The reaction equation is as follows:



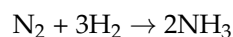
(2) Methanol Synthesis

This route produces green methanol by reacting electrolytic hydrogen with captured carbon dioxide. The reaction equation is as follows:



(3) Green Ammonia Production

The green ammonia production primarily occurs through the Haber-Bosch (HB) ammonia synthesis reactors, where the mixture of nitrogen and hydrogen is synthesized into ammonia with an iron-based catalyst. The reaction equation is as follows:



2.3. Technical Route Decision-Making Framework for IEPU Based on Techno-Economic Analysis

To enable the systematic and rational selection of key P2X technology routes for the IEPU, this paper develops a comprehensive evaluation framework—“technology selection—economic analysis—risk assessment”. Technology selection provides the technical foundation, economic analysis validates financial feasibility, and risk assessment ensures robustness under uncertainty, as illustrated in Figure 3.

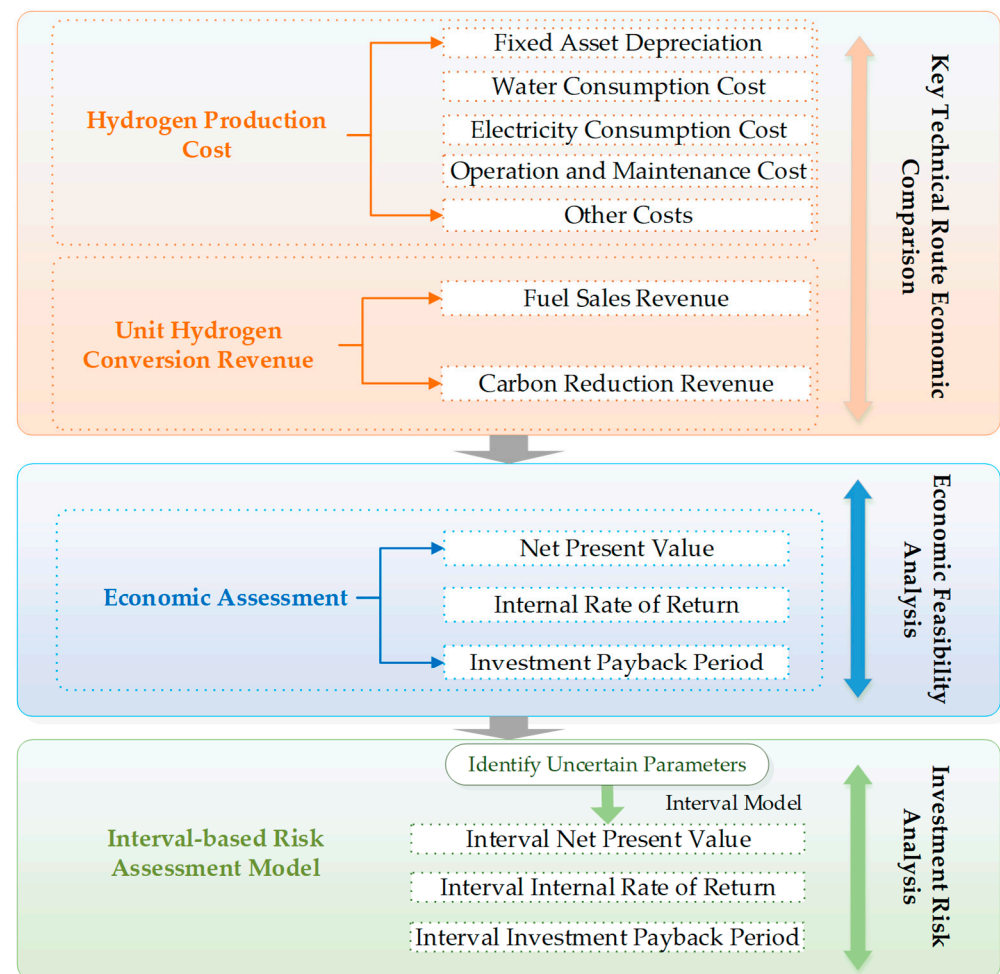


Figure 3. Selection Roadmap of the key technical routes for IEPU.

Firstly, for electrolytic hydrogen production, a comparative analysis of the levelized cost of hydrogen (LCOH) for AWE and PEM is conducted. The analysis integrates key cost factors, including initial investment, operational energy consumption, and material usage, to determine the optimal route from an economic perspective. Secondly, regarding hydrogen utilization, a model calculates the unit hydrogen conversion revenue for methane synthesis, methanol synthesis, and green ammonia production, integrating product price, potential carbon credit revenue, and operational energy costs. Subsequently, the optimal “electrolysis–utilization” combination route is embedded in a typical IEPU retrofit scenario. By conducting a life-cycle cost-benefit analysis and integrating core financial indicators such as net present value (NPV), internal rate of return (IRR), and discounted payback period (PP), the economic feasibility of this route is systematically verified. Finally, investment risks are quantified by applying interval number theory. This involves constructing an interval-based risk assessment model to calculate key interval metrics (e.g., NPV and IRR) for the project. Thereby, the risk resilience of the optimal route can be assessed amidst fluctuating market and policy environments.

3. Decision-Making Model for Key Processes of P2X Technology

3.1. Decision-Making Model for Hydrogen Production by Electrolysis Based on Unit Cost

The LCOH is used to compare AWE and PEM technologies. For an electrolysis unit of a given capacity, the LCOH is calculated considering annualized cost and annual output, as shown in Equation (1):

$$C = \frac{C_D + C_W + C_e + C_o + C_M}{m_{H_2}} \quad (1)$$

where C is the levelized cost of hydrogen; m_{H_2} is the hydrogen production volume; C_D is the depreciation of fixed assets; C_W is the water consumption cost; C_e is the electricity consumption cost; C_o are the other costs; C_M is the operation and maintenance cost. The other costs consumed by alkaline electrolysis mainly consider KOH.

$$C_D = \frac{C_i(1 - V_r)}{YT} \quad (2)$$

$$C_W = m_W P_W \quad (3)$$

$$C_e = m_e P_e \quad (4)$$

$$C_o = m_o P_o \quad (5)$$

$$C_M = 3.5\% C_i \quad (6)$$

where C_i is the initial investment cost of the electrolyzer; V_r is the expected residual value rate; Y is the depreciation period; T is the annual operating hours; m_W is the water consumption of the electrolyzer; P_W is the industrial water price; m_e is the electrical energy consumption of the electrolyzer; m_o is the consumption of other materials; P_o is the price of other materials.

3.2. Decision-Making Model for Hydrogen Utilization Processes Based on Unit Revenue

The unit hydrogen conversion revenue refers to the net revenue from converting a unit of hydrogen into methane, methanol, or green ammonia during the fuel conversion process, after deducting various costs and expenses. Calculating the unit hydrogen conversion revenue, the economic viability and profitability of the hydrogen utilization project can be evaluated.

This study analyzes and compares three routes—methane synthesis, methanol synthesis, and green ammonia production—based on their respective unit hydrogen conversion revenue. The production costs of each chemical product consist of two parts: fixed and variable costs. Fixed costs include the capital investment and annual operation and maintenance costs. Variable costs include raw material costs and energy consumption costs. Among these, the CO_2 feedstock cost is from CCUS systems for thermal power generation, the N_2 feedstock cost is obtained by air separation processes, and the hydrogen feedstock cost is the levelized hydrogen cost derived from the aforementioned alkaline electrolysis process. Furthermore, as the production of methane and methanol synthesis processes utilizes captured CO_2 as the raw material, the overall production process can reduce CO_2 emissions, offering carbon reduction benefits. Therefore, considering the corresponding carbon revenue, the calculation formulas for the unit hydrogen conversion revenue under the three routes are shown in Equations (7)–(10):

$$C_{CH_4}^{ci} = P_{CH_4} - \left(P_e + \frac{C_{CH_4m}^i}{G_{CH_4}^T} + \frac{C_{CH_4m}^O}{G_{CH_4}} + C_{CO_2} + C_{H_2} \right) + R_{CH_4} \quad (7)$$

$$C_{\text{CH}_3\text{OH}}^{\text{ci}} = P_{\text{CH}_3\text{OH}} - \left(P_e + \frac{C_{\text{CH}_3\text{OHm}}^i}{G_{\text{CH}_3\text{OH}}^T} + \frac{C_{\text{CH}_3\text{OHm}}^O}{G_{\text{CH}_3\text{OH}}} + C_{\text{CO}_2} + C_{\text{H}_2} \right) + R_{\text{CH}_3\text{OH}} \quad (8)$$

$$C_{\text{NH}_3}^{\text{ci}} = P_{\text{NH}_3} - \left(P_e + \frac{C_{\text{NH}_3}^i}{G_{\text{NH}_3}^T} + \frac{C_{\text{NH}_3}^O}{G_{\text{NH}_3}} + C_{\text{N}_2} + C_{\text{H}_2} \right) \quad (9)$$

$$R_{\text{CH}_4}(R_{\text{CH}_3\text{OH}}) = P_C \cdot E_{\text{CO}_2} \quad (10)$$

where $C_{\text{CH}_4}^{\text{ci}}$, $C_{\text{CH}_3\text{OH}}^{\text{ci}}$, and $C_{\text{NH}_3}^{\text{ci}}$ respectively represent the unit hydrogen conversion revenue for synthesizing methane, methanol, and green ammonia; P_{CH_4} , $P_{\text{CH}_3\text{OH}}$, and P_{CH_4} respectively represent the unit selling price of methane, methanol, and ammonia. P_e is the unit electricity consumption cost of the corresponding synthesis equipment. $C_{\text{CH}_4\text{m}}^i$, $C_{\text{CH}_3\text{OHm}}^i$, and $C_{\text{NH}_3\text{m}}^i$ are the investment costs for the methanation equipment, methanolization equipment, and synthetic ammonia equipment, respectively. $C_{\text{CH}_4\text{m}}^O$, $C_{\text{CH}_3\text{OHm}}^O$, and $C_{\text{NH}_3\text{m}}^O$ are the operation and maintenance costs for the methanation equipment, methanolization equipment, and synthetic ammonia equipment, respectively. $G_{\text{CH}_4}^T$, $G_{\text{CH}_3\text{OH}}^T$, and $G_{\text{NH}_3}^T$ are the total methane production, methanol production, and ammonia production over the entire life-cycle of the methanation equipment, methanolization equipment, and synthetic ammonia equipment, respectively. G_{CH_4} , $G_{\text{CH}_3\text{OH}}$, and G_{NH_3} are the annual production volumes of methane, methanol, and ammonia, respectively. C_{CO_2} , C_{H_2} , and C_{N_2} are the CO_2 capture cost per unit, hydrogen levelized cost, and nitrogen per unit, respectively. R_{CH_4} and $R_{\text{CH}_3\text{OH}}$ are the carbon emission reduction revenues from synthesizing methane and methanol, respectively; P_C is the carbon trading price; E_{CO_2} is the amount of carbon dioxide emission reduction.

4. Life-Cycle Economic Evaluation Model for IEPU Retrofit Project

4.1. Life-Cycle Cost Model for IEPU Retrofit Project

The total life-cycle cost of an IEPU retrofit project is categorized into initial investment and operational costs. The initial investment accounts for the upfront investment in equipment and future electrolyzer replacements. The operational costs, on the other hand, include ongoing expenses for maintenance and production.

(1) Initial investment of IEPU Retrofit Project

The initial investment C_1 for IEPU retrofit projects primarily consists of seven components: the procurement and installation expenses for carbon capture units, electrolyzers, photovoltaic systems, methanation reactors, hydrogen storage and carbon storage facilities, as well as the costs of electrolyzer replacement. The cost is shown in Equation (11):

$$C_1 = C_c + C_e + C_p + C_m + C_h + C_s + C_2 \quad (11)$$

where C_c is the initial investment of the carbon capture unit, C_e is the electrolyzer initial investment, C_p is the initial investment of the PV system, C_m is the initial investment of the methanation reactor, C_h and C_s are the initial investments of the hydrogen and carbon storage facilities, and C_2 is the replacement cost of electrolyzers.

These initial investments for each major unit are scale-dependent, calculated as the product of its unit cost and installed capacity, as shown in Equation (12):

$$C_j = U_j I_j \quad (12)$$

where U_j is the unit cost of the i -th device, I_j is the installed capacity of the i -th device, and C_j is the i -th device's initial investment.

Given that the service life of an electrolyzer (typically 5–10 years) is shorter than the overall lifespan of the IEPU system, a replacement is required during operation. The replacement cost C_2 is calculated as follows:

$$C_2 = U_{e'} I_e \quad (13)$$

where $U_{e'}$ is the electrolyzer replacement unit cost, and I_e is the installed electrolyzer capacity.

(2) Operational Expenditures of the IEPU Retrofit Project

The total operating cost C_{op} consists of two components: the operation and maintenance (O&M) cost $C_{O\&M}$ of the various equipment and the production costs C_{prod} . These are calculated as follows:

$$C_{op} = C_{O\&M} + C_{prod} \quad (14)$$

$$C_{O\&M} = \sum \lambda C_i \alpha_i \quad (15)$$

where λ is the capital formation ratio, and C_i and α_i represent the initial investment and the annual O&M cost factor, respectively, for the i -th type of equipment.

$$C_4 = Q_u P_u + Q_w P_w \quad (16)$$

where Q_u and Q_w represent the annual coal consumption and annual water consumption of the IEPU retrofit project, respectively; P_u and P_w represent the unit price of coal and water, respectively. The detailed calculation of Q_u is given by Equation (17):

$$Q_u = \frac{E_g + E_e}{H \cdot NCV \cdot 1000} \quad (17)$$

where E_g represents the annual grid feed-in electricity from the IEPU retrofit project; E_e denotes the annual on-site electricity consumption (e.g., for electrolysis); η indicates the net plant efficiency; and NCV is the coal net calorific value.

The total annual water consumption, comprising electrolytic and cooling demands, is determined by Equations (18)–(20):

$$Q_w = Q_d + Q_l \quad (18)$$

$$Q_d = \frac{m_{H_2}}{18} \cdot \frac{1000}{2} \cdot \eta_d \quad (19)$$

$$Q_l = \frac{F_R \cdot 1000}{C_p \cdot \Delta T} \cdot \varepsilon \quad (20)$$

where Q_d and Q_l are the annual water consumption for electrolysis and cooling; η_d is the electrolysis efficiency; F_R is the cooling heat load; C_p is the specific heat capacity of water; ΔT is the cooling water temperature rise; ε is the water circulation system loss rate.

4.2. Life-Cycle Revenue Model for IEPU Retrofit Project

The revenue of IEPU retrofit projects primarily comprises revenue from electricity sales, methane sales, carbon capture tax credits, and residual value recovery, as calculated in Equation (21):

$$R = Q_e P_e + Q_m P_m + Q_c P_c + C_1 \beta \quad (21)$$

where Q_e is the electricity sales volume; P_e is the electricity sales price; Q_m is the methane sales volume; P_m is the methane sales price; Q_c is the mass of CO₂ captured; P_c is the unit value of carbon captured (e.g., tax credit price); β is the residual value recovery factor.

The electricity sales volume Q_e is calculated specifically by Equation (22):

$$Q_e = 2,400,000,000 \times (1 - \eta_{ce}) - E_g \quad (22)$$

where η_{ce} is the electricity utilization rate.

The chemical product sales volume is calculated using Equation (23):

$$Q_m = m_{H_2} \cdot \psi \cdot Y \quad (23)$$

where for each product i (CH_4 , CH_3OH , NH_3): ψ is the stoichiometric coefficient (moles of CO_2 consumed per mole of product); Y is the synthesis efficiency.

The corresponding CO_2 capture volume $M_{CO_2,i}$ is determined from Equations (24) and (25):

$$Q_C = m_{CO_2} \cdot \eta_{CO_2} \quad (24)$$

$$m_{CO_2} = Q_u \cdot C_{Ch} \cdot \frac{44}{12} \quad (25)$$

where m_{CO_2} is the annual CO_2 emissions; η_{CO_2} is the CO_2 capture rate; C_{Ch} is the carbon (mass) fraction of coal.

4.3. Life-Cycle Economic Benefit Assessment Model for IEPU Retrofit Project

Considering the time value of money, the life-cycle economic benefits of an IEPU retrofit project are evaluated using key financial metrics: NPV, IRR, and PP. The corresponding calculation models are given by Equations (26)–(28):

$$NPV = \sum_{t=0}^n \frac{[R(t) - (C_y(t) + C_z(t))]}{(1+r)^t} - C_1 \quad (26)$$

$$0 = \sum_{t=0}^n \frac{[R(t) - (C_y(t) + C_z(t))]}{(1+IRR)^t} - C_1 \quad (27)$$

$$0 = \sum_{t=0}^{Pt} \frac{[R(t) - (C_y(t) + C_z(t))]}{(1+IRR)^t} - C_1 \quad (28)$$

where $R(t)$, $C_y(t)$, and $C_z(t)$ are revenue, operational cost, and financing cost in year t ; n is project lifetime; r is discount rate; IRR is internal rate of return; P_t is discounted payback period.

The financing costs $C_{fin,t}$ for the IEPU retrofit project comprises the costs of working capital and long-term debt, as given by Equation (29):

$$C_{fin,t} = C_5 + C_6 \quad (29)$$

where C_5 and C_6 denote the annual financing costs for working capital and long-term debt, respectively. These costs scale directly with the amount of capital raised. The scaling equations are given by Equations (30)–(32):

$$C_5 = L_5 \cdot I_5 \quad (30)$$

$$L_5 = F_5 \cdot P_5 \quad (31)$$

$$F_5 = A_5 \cdot D_5 \quad (32)$$

where for annual financial metrics: L_5 is working capital loan amount; I_5 is working capital loan interest rate; F_5 is working capital; P_5 is working capital loan ratio (proportion of working capital financed by debt); A_5 is current assets; D_5 is current liabilities.

The annual taxes payable consists of three components: value-added tax (VAT), VAT surcharges, and revenue tax. It is calculated using Equation (33).

$$T = T_v + T_a + T_t \quad (33)$$

where T_v , T_a and T_t are the payable amounts for VAT, VAT surcharges, and revenue tax, respectively. Their calculations, based on deductible items and taxable revenue, are provided by Equations (34) and (35):

$$T_v = (R - C_y) \cdot I_v \quad (34)$$

$$T_a = T_v \cdot I_a \quad (35)$$

where I_v and I_a are the VAT rate and the VAT surcharge rate, respectively.

A project is considered economically viable if its NPV is greater than or equal to zero, indicating that it can cover all investments after considering the time value of money. A higher NPV represents greater value creation and investment efficiency. An IRR that exceeds the hurdle rate (or required rate of return) signifies that the project's profitability satisfies the cost of capital, making it an attractive investment. A shorter PP indicates faster capital recovery, thereby implying lower project liquidity risk.

5. Investment Risk Assessment Model for IEPU Retrofit Project Based on Interval Numbers

5.1. Investment Risk Identification

IEPU retrofit projects are characterized by a substantial investment scale, high technological integration, an extended life-cycle, and strong policy dependence. The inherent investment risk stems from uncertainties in key economic parameters, which propagate through cash flow mechanisms, potentially causing project returns to deviate from projections. Building on the operational and life-cycle economic assessment models developed for the selected technical route, this study systematically identifies investment risks across three core dimensions: market, policy, and finance.

(1) Market Risk

Market risk arises primarily from the volatility of key commodities and energy prices in a market-driven environment. Project revenue depends mainly on electricity and green fuel sales. Among these, the feed-in tariff, subject to regional electricity supply-demand balance, renewable integration policies, and market rules, directly determines electricity sales revenue. Meanwhile, the market price of green fuels (e.g., methane, methanol) is driven by fossil fuel prices, green premiums, and feedstock competition. Uncertainty in these prices directly affects the project's core business revenue. Collectively, these price volatilities define the core market risk.

(2) Policy Risk

Policy risk is predominantly associated with uncertainty in carbon-related regulations. The carbon price is a central policy lever linking environmental performance to revenue. Changes in China's emissions allowance, the eligibility and offset rules for Chinese certified emissions reductions, market liquidity, or price stability mechanisms would directly affect the project's CCUS credit revenue.

(3) Financial Risk

Financial risk focuses on uncertainties in initial investment during project execution and early operation. Fluctuations in the total capital investment are the primary manifestation. Key equipment, including electrolyzers, high-pressure carbon capture units, and catalytic synthesis reactors, undergoes rapid technological iteration. Their costs are sensitive to raw material markets and global supply chains. Furthermore, the complex system integration entails inherent risks of cost overruns in design and construction. Higher initial investment increases annual depreciation, alters the capital structure and thus the weighted average cost of capital, ultimately exerting an amplified adverse effect on key financial indicators such as NPV and PP.

5.2. Investment Risk Assessment Model Based on Interval Numbers

To quantify the investment risk induced by the volatility of key parameters and to delineate the impact boundaries of uncertainty on economic viability, this study employs interval theory. This approach substitutes deterministic parameters in conventional economic assessment models with interval numbers. This substitution effectively captures the plausible fluctuation ranges of these parameters over the project's life-cycle.

Building upon a comprehensive set of indicators—including value, ratio, and time-based metrics—the model evaluates investment risk for retrofit projects using three interval metrics: I-NPV, I-IRR, and interval discounted payback period (I-PP).

The core of the modeling approach is to replace crisp parameters with interval numbers. Formally, let the true value of an uncertain parameter be x and define its possible range as an interval number:

$$\tilde{x} = [x^-, x^+]$$

where x^- and x^+ are the lower bound and upper bound of the interval, respectively.

The calculations for I-NPV, I-IRR, and I-PP follow from Equations (36)–(38):

$$[NPV] = \sum_{t=0}^n \left[\frac{\tilde{R}(t) - \tilde{C}(t)}{(1+r)^t} \right] \quad (36)$$

$$[0, 0] = \sum_{t=0}^n \left[\frac{\tilde{R}(t) - \tilde{C}(t)}{(1+[IRR])^t} \right] \quad (37)$$

$$[0, 0] = \sum_{t=0}^{[Pt]} \left[\frac{\tilde{R}(t) - \tilde{C}(t)}{(1+IRR)^t} \right] \quad (38)$$

where: $[NPV]$ is the interval net present value; $\tilde{R}(t)$ is the interval revenue in year t ; $\tilde{C}(t)$ is the interval cost in year t ; $[IRR]$ is the interval internal rate of return; $[Pt]$ is the interval discounted payback period.

Interpretation:

I-NPV: The lower and upper bounds establish the risk threshold for the project. The position of this interval relative to zero indicates the range of possible outcomes for investment recovery and risk resilience.

I-IRR: This interval represents the possible profitability range of the project profitability under uncertainty. Comparing the entire interval, and especially its lower bound, to the hurdle rate helps assess whether the required return is achievable across the spectrum of possible scenarios, providing a direct measure of downside risk.

I-PP: The width of this interval directly quantifies the sensitivity of the capital recovery period to input fluctuations. A wider interval implies greater uncertainty in payback time and, consequently, higher liquidity risk.

Collectively, these interval metrics provide a robust quantitative foundation for a comprehensive risk assessment, enabling more informed and resilient investment decisions under uncertainty.

6. Cause Study

6.1. Comparative Selection of Key Processes in P2X Technology Route

6.1.1. Basic Data

For the electrolytic hydrogen production, this study employs an LCOH model to systematically compare AWE and PEM electrolysis technologies. The operating costs include water electrolysis encompass electricity, water, other material consumption (e.g., KOH for AE), and maintenance. The annual maintenance cost is estimated at 3.5% of the initial investment. Fixed assets are depreciated over a 5-year period with a 5% residual value, assuming an annual operating duration of 7000 h. Based on current market research data, the cost parameters for electrolytic hydrogen production are summarized in Table 4, while those for hydrogen utilization technologies are presented in Table 5. Detailed data sources and corresponding years for the cost parameters are provided in Appendix A.

Table 4. Cost parameters for electrolytic hydrogen production [2,31–40].

Name	Value	Unit
AWE equipment	2000	CNY/kW
PEM equipment	7196	CNY/kW
SOEC equipment	19,600	CNY/kW
Electricity consumption for alkaline electrolysis	4	kWh/Nm ³ ·H ₂
Electricity consumption for PEM electrolysis	3.54	kWh/Nm ³ ·H ₂
Electricity consumption for SOEC electrolysis	3.1	kWh/Nm ³ ·H ₂
Electricity price	0.2	CNY/kWh
Water consumption	0.36	t/h
Industrial water price	4.5	CNY/t
KOH loss	1.9	g/kg H ₂
KOH price	5.7	CNY/kg

Table 5. Cost Parameters for Hydrogen Utilization Technologies [8,41–45].

Cost and Expense Item	Value	Unit
Methane price	4	CNY/Nm ³
Methanol price	2.2	CNY/kg
Ammonia price	2.4	CNY/kg
Methane synthesis equipment investment cost	4800	CNY/kW
Methane synthesis equipment maintenance cost	144	CNY/kW/year
Methane synthesis equipment life-cycle	20	Years
Methanol synthesis equipment investment cost	4000	CNY/kW
Methanol synthesis equipment maintenance cost	120	CNY/kW/year
Methanol synthesis equipment life-cycle	20	Years
Ammonia synthesis plant investment cost	4111	CNY/ton
Ammonia synthesis plant maintenance cost	123	CNY/ton/year
Ammonia synthesis plant life-cycle	15	Years
Carbon trading price	210	CNY/ton
Annual production capacity of methane per nit capacity	70,000	tons/year
Annual production capacity of methanol per nit capacity	840,000	tons/year
Annual production capacity of ammonia per unit capacity	84,000	tons/year

6.1.2. Selection of Electrolytic Hydrogen Production Processes

The levelized cost of hydrogen for the three mainstream water electrolysis technologies is compared in Figure 4. The calculation results show that AWE exhibits the lowest LCOH at 0.95 CNY/Nm³·H₂, which is approximately 22.8% lower than PEM (1.23 CNY/Nm³·H₂) and 45.7% lower than SOEC (1.75 CNY/Nm³·H₂). This cost hierarchy is consistent with

recent multi-technology comparative studies [22–24], all of which identify AWE as the most economically viable option under current techno-economic conditions.

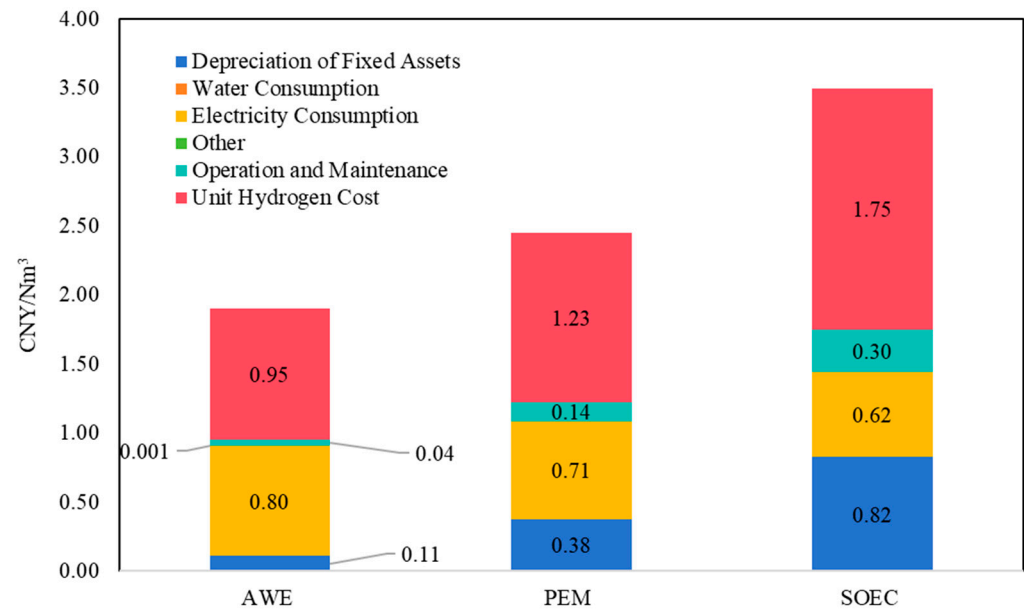


Figure 4. Cost comparison of different electrolytic hydrogen production technologies.

To assess the robustness of this conclusion under varying renewable penetration levels, a sensitivity analysis of the electricity price on LCOH is conducted. In IEPU/P2X systems, hydrogen production preferentially utilizes surplus renewable electricity that would otherwise be curtailed. As this surplus power has near-zero marginal cost, higher renewable penetration increases its availability and lowers the average electricity cost for hydrogen production. Thus, the electricity price serves as an effective proxy for renewable energy penetration, with lower prices reflecting greater utilization of surplus renewables. Figure 5 illustrates the sensitivity of the three electrolytic hydrogen production technologies to the electricity price. The results indicate that AWE maintains its cost advantage across all levels of renewable penetration, as reflected by electricity price variations of $\pm 20\%$ from the baseline.

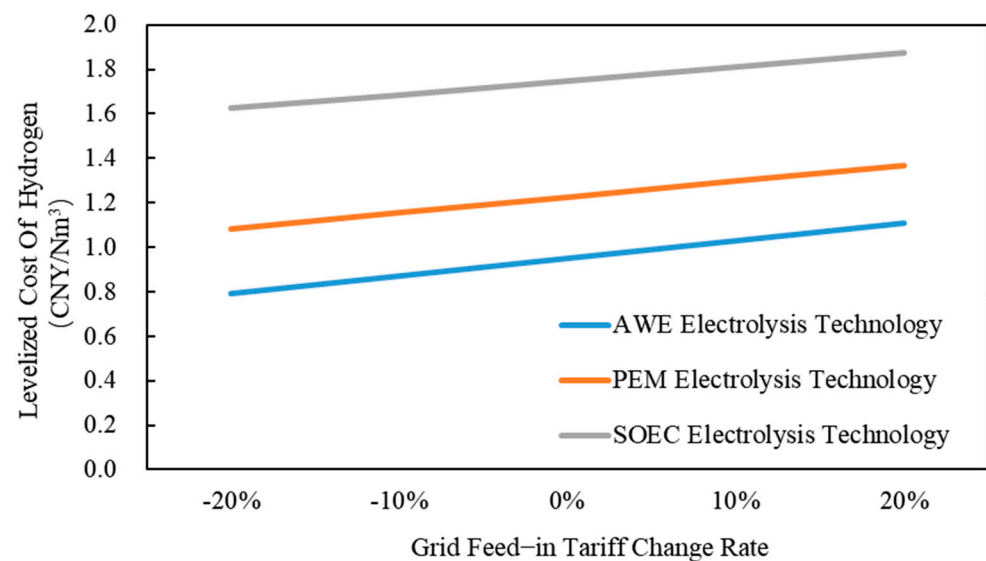


Figure 5. The electricity price impact on levelized cost of hydrogen.

The underlying reasons for this consistent cost advantage can be traced to two fundamental factors. From a cost perspective, PEM technology relies on expensive proton exchange membranes and platinum-based catalysts, and SOECs also have high expenses attributed to bespoke materials and insulation. Both of which lead to a significantly higher initial equipment investment compared to AWE, which utilizes nickel-based electrodes and alkaline electrolyte. From an operational and commercial perspective, the AWE benefits from greater commercial maturity, a well-established supply chain, and pronounced economies of scale. SOEC systems are still in the early stages of commercialization, with their scale constrained. These factors collectively contribute to lower operation and maintenance costs, resulting in superior lifecycle economics.

6.1.3. Selection of Hydrogen Utilization Process

The unit hydrogen conversion revenue of the hydrogen utilization technologies, including methane synthesis, methanol synthesis, and green ammonia production, is shown in Table 6. The calculation results show that methane synthesis achieves the highest economic return at 0.22 CNY/kg H₂, outperforming green ammonia production (0.17 CNY/kg H₂) and methanol synthesis (0.12 CNY/kg H₂). This finding aligns with and extends the recent literature [41], which examined these three routes from the perspectives of technological maturity and market flexibility. The study notes that methane and ammonia exhibit higher technological maturity, while methanol offers greater market adaptability. Compared with the qualitative research conducted in a recent paper, the present study contributes quantitative economic evidence to this qualitative framework. The main reason is that the selling price of methane is higher than that of the other two products, while there is no significant difference in the unit investment cost, operation, and maintenance cost among the three schemes. Although the electricity cost under the methane synthesis route is higher than the other two routes, the selling price of methane can cover the higher electricity cost, and the carbon revenue price of methane synthesis is higher than that of the methanol synthesis. Even if the green ammonia production does not involve carbon revenue, its lower electricity cost still renders it more economically viable than the methanol route.

Table 6. The unit hydrogen conversion revenue of hydrogen utilization techniques.

Technique	Unit Hydrogen Conversion Revenue	Unit
Methane synthesis	0.22	CNY/kg
Methanol synthesis	0.12	CNY/kg
Green ammonia production	0.17	CNY/kg

Taking all the above circumstances into consideration, methane synthesis is selected as the optimal hydrogen utilization route and is integrated into the subsequent IEPU retrofit analysis.

This study conducts a sensitivity analysis to explore the economic performance differences among the three technical routes under various renewable penetration scenarios. Electricity price is used as a proxy for renewable energy penetration, with unit hydrogen conversion revenue as the evaluation indicator.

To further investigate the economic performance differences among the three technical routes under varying renewable penetration scenarios, a sensitivity analysis is conducted using electricity price as a proxy for renewable energy penetration, with unit hydrogen conversion revenue as the evaluation indicator. The results are illustrated in Figure 6. Methane synthesis is the most sensitive to renewable penetration, due to its higher electricity consumption. In the context of reduced electricity costs due to the increased penetration of

renewable energy, the unit revenue advantage of methane synthesis is substantially higher than that of methanol synthesis and green ammonia production. On the contrary, in the context of continuously rising electricity prices, since the electricity consumption required for methanol synthesis and green ammonia production is lower, these two methods have gradually become more economically viable compared to methane synthesis.

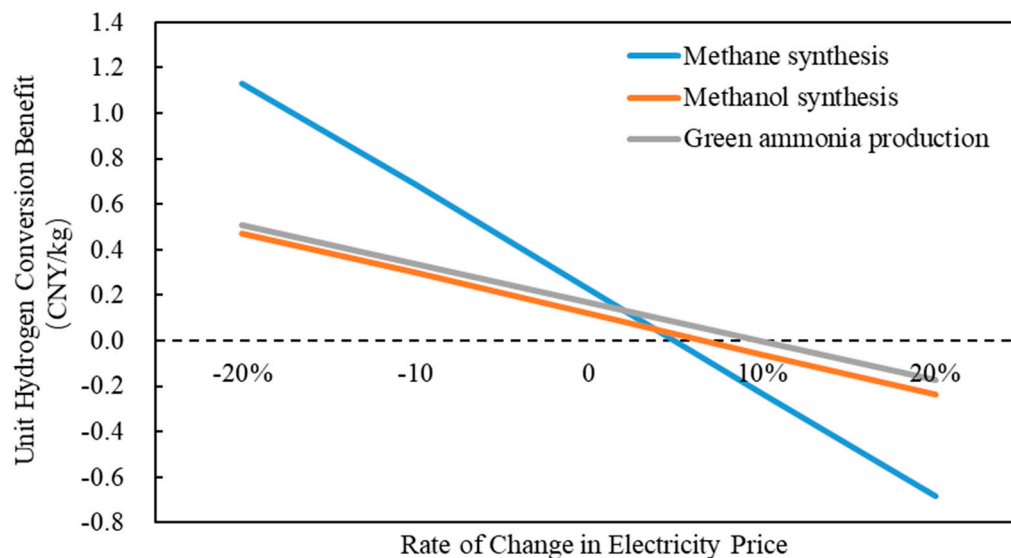


Figure 6. The electricity price impact on unit hydrogen conversion revenue.

Considering the potential market uncertainties associated with fuels, fluctuations in final product prices impose constraints on the maximum acceptable cost of renewable electricity generation. To address this problem, a sensitivity analysis is conducted on the relationship between the acceptable cost of renewable energy generation (LCOE) and the product selling price for the three hydrogen utilization routes.

As illustrated in Figure 7, the acceptable renewable energy LCOE demonstrates a positive correlation with fuel selling prices across all three routes. Notably, the methane synthesis route consistently tolerates the highest renewable energy costs at every fuel price level, indicating that this pathway offers a crucial buffer against electricity market uncertainty. Furthermore, all three routes exhibit high sensitivity to product price declines: a 20% reduction in fuel prices lowers the acceptable LCOE by 22–25% across all pathways. This uniform sensitivity underscores that downside risk in fuel markets directly translates into tighter cost constraints on renewable energy infrastructure, thereby affecting the overall economic feasibility of IEPUs.

6.1.4. Comprehensive Evaluation of P2X Technology Selection

The preceding analyses identified “AWE + methane synthesis” as the optimal technology combination under baseline economic assumptions. However, robust technology selection for IEPUs retrofit projects requires a deeper examination of how technological maturity, investment cost sensitivity, and infrastructure synergies collectively influence long-term feasibility. This section integrates these dimensions to provide a comprehensive evaluation of the competing P2X pathways.

To evaluate the economic impact of technological maturity, a sensitivity analysis of the LCOH to variations in electrolyzer investment cost was conducted, as shown in Figure 8. The results reveal starkly different economic sensitivities. AWE shows the strongest cost rigidity due to its mature technology and well-established supply chain. Its LCOH is mainly determined by operational costs, making it less susceptible to variations in investment

costs. Although SOEC has high efficiency, due to its excessively high initial investment cost, it is difficult to be economically competitive within any sensitivity range.

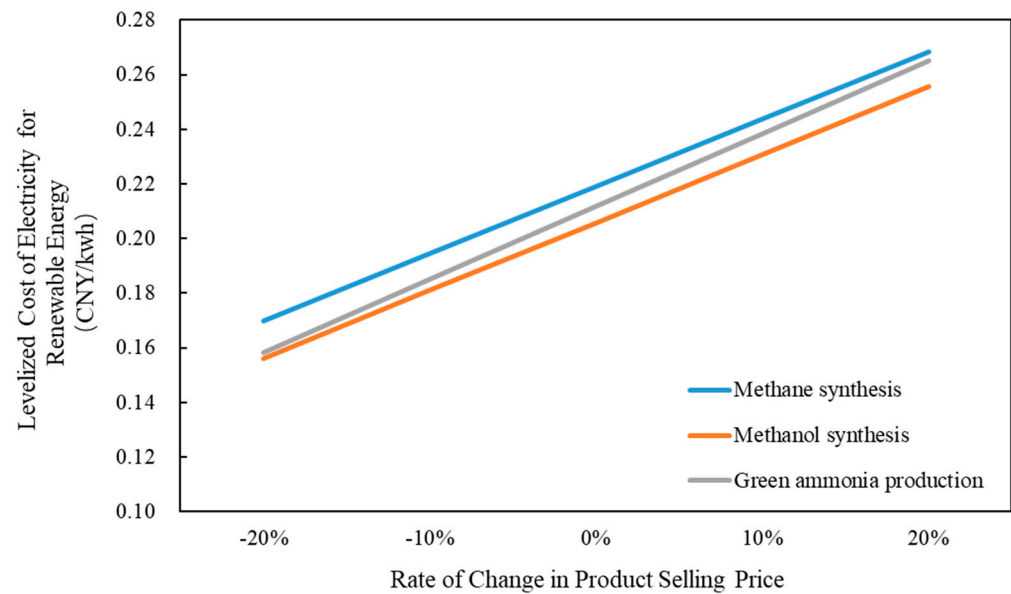


Figure 7. The product selling price impact on acceptable renewable energy LCOE.

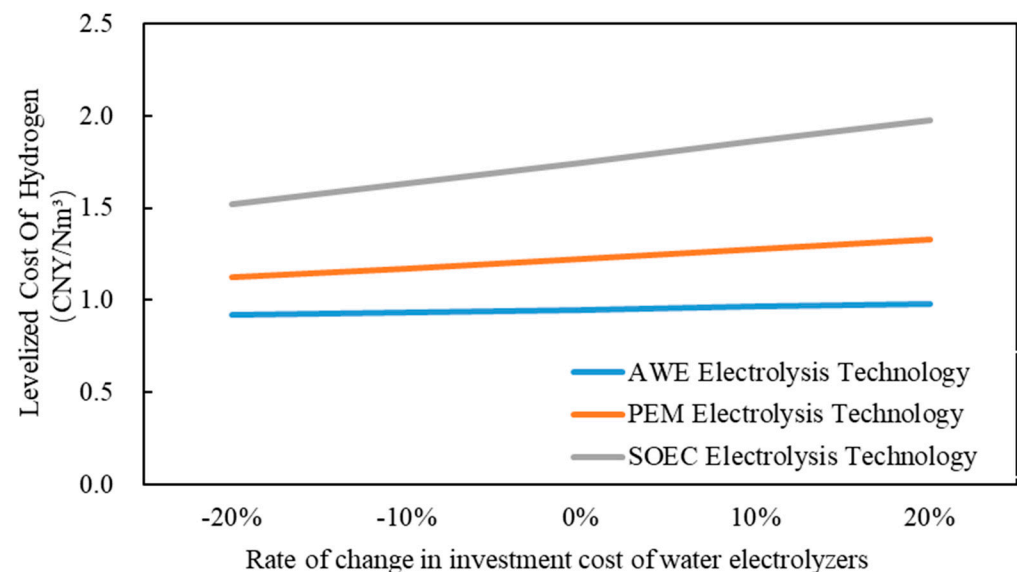


Figure 8. Sensitivity of Levelized Cost of Hydrogen to Variations in Water Electrolyzer Investment Cost.

The selection of AWE as the optimal route is further supported by its technological maturity and proven scalability, reflected in its widespread commercial deployment and established supply chain. While PEM offers superior dynamic response suitable for highly intermittent renewable integration, its current higher investment cost constrains its near-term applicability. The unresolved durability issues of SOEC under variable operation further limit its readiness for integration with fluctuating renewable power. These considerations of maturity and flexibility further validate the suitability of AWE for the baseline IEPU configuration. Nevertheless, future technology advancements are expected to alter the competitive landscape over the long term. These include reduced precious metal loadings in PEM and enhanced thermal cycling resistance in SOEC, which may improve their competitiveness in specific niche applications.

Similarly, the economic sensitivity of the three hydrogen utilization routes to variations in their respective synthesis equipment investment costs was analyzed, with results presented in Figure 9. Within the $\pm 20\%$ investment cost fluctuation range, methane synthesis exhibits not only the highest baseline unit hydrogen conversion revenue but also the greatest sensitivity to investment cost variations. This dual characteristic implies significant profit upside potential from future equipment cost reductions, while simultaneously indicating stronger economic constraints from upfront fixed investment during the project's initial phase. In contrast, both green ammonia production and methanol synthesis demonstrate relatively lower sensitivity, with their revenue curves exhibiting greater stability and superior resistance to capital cost fluctuations.

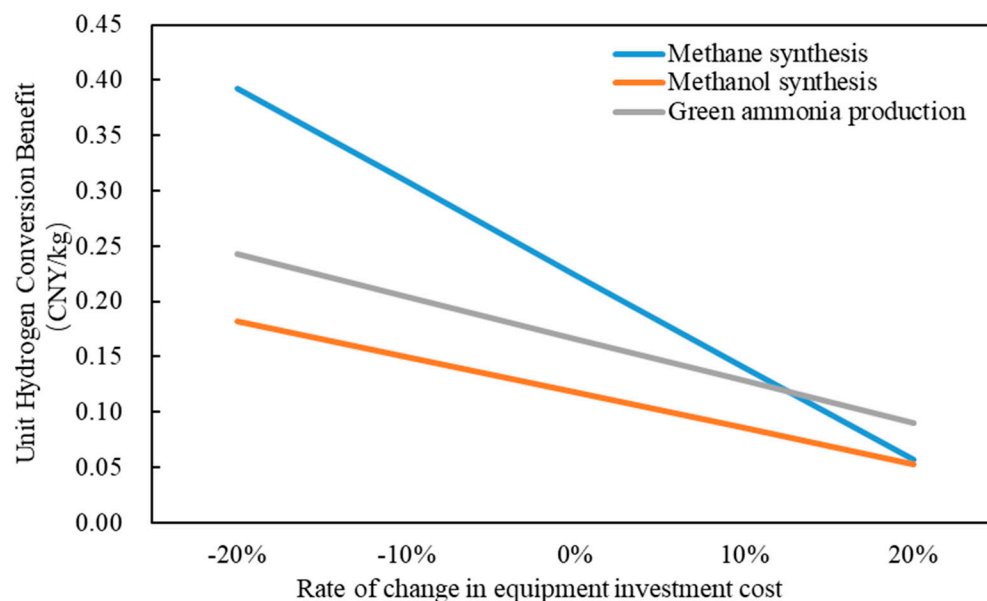


Figure 9. Sensitivity of unit hydrogen conversion benefit to variations in equipment investment cost.

Beyond investment cost sensitivity, the future competitiveness of these pathways is shaped by upstream and downstream uncertainties. Electrolytic hydrogen costs, contingent upon the maturity of electrolysis technologies, will fundamentally influence the economics of all downstream routes. On the demand side, methane benefits from its current price advantage and established carbon credit mechanisms, while methanol offers greater market flexibility as a versatile chemical feedstock. Green ammonia holds great potential for long-term development opportunities. Its application prospects in offshore decarbonization and direct blending in coal-fired power plants can bring about a large number of new demands. As the carbon market expands, this may make its economic appeal surpass that of methane.

Based on its superior current economic performance and significant infrastructure synergies, the “AWE + methane synthesis” route is selected as the optimal configuration. This pathway integrates directly with existing natural gas networks for methane delivery and utilizes on-site CO₂ capture from the coal-fired unit. This design eliminates dependencies on external feedstocks, reduces vulnerability to supply chain disruptions, and avoids additional capital expenditures for dedicated transport and storage infrastructure.

6.2. Economic Evaluation Results and Analysis of the IEPU Retrofit Project

6.2.1. Retrofit Plan and Basic Data

This study selects alkaline electrolyzed water and methane synthesis as the optimal technological routes for the IEPU system, applying them to the retrofit project of 600 MW existing thermal power plants to evaluate the system-level life-cycle economic feasibility. The capacity of each key piece of equipment is determined based on systematic balancing

principles to ensure continuous and stable production: the annual average operating hours of the main equipment are determined with reference to industry benchmarks; the total annual hydrogen demand is derived from the fixed-rate CO₂ output of the power plant and the stoichiometry of the methanation reaction. The electrolyzer capacity is determined based on the hydrogen demand and its designated operating hours, with the photovoltaic power supply is configured at a certain ratio; the methane synthesis reactor capacity is determined according to the hydrogen processing rate and reaction kinetics; the intermediate storage tanks for hydrogen and carbon dioxide are designed to hold a specified duration of output from their respective upstream production equipment under rated load, thereby enhancing operational flexibility and system stability. The key technical parameters of each piece of equipment within the system were determined based on the above principles, as shown in Table 7. The life-cycle of the project is set at 21 years. The economic assessment covered the initial investment, operation, and maintenance costs, energy consumption, and raw material costs in the production process, as well as multiple revenue streams, including electricity sales, methane sales, and carbon capture tax rebates. The main economic parameters and related tax rate involved in the system operation are shown in Tables 8 and 9, respectively. Detailed data sources and corresponding years for the cost parameters are provided in Appendix A.

Table 7. Key technical equipment parameters within IEPU [42–44,46,47].

Equipment Type	Project Name	Value	Unit
Thermal power unit	Capacity	600	MW
	Power generation coal consumption	305.5	gce/kWh
	Carbon capture power consumption	310.3	kWh/tCO ₂
	Annual running hours	4000	h
	Annual carbon capture	398,000	tons
Carbon capture device	Carbon capture power consumption	310.3	kWh/tCO ₂
	Annual carbon capture	398,000	tons
Electrolyzer	Unit energy consumption	4.2	kWh/Nm ³ ·H ₂
	Annual running hours	7000	h
Photovoltaic	Annual running hours	1300	h
Methane synthesis Equipment	Unit energy consumption	0.3	kWh/Nm ³ ·H ₂

Table 8. Key economic parameters within IEPU [8,36,38,39,45,48–50].

Equipment Type	Project Name	Value	Unit
Carbon capture device	Investment cost	68,767	×10 ⁴ CNY
Electrolyzer	Investment cost	2000	CNY/kW
	Replace years	5	Year
	Replace unit cost	1000	CNY/kW
Photovoltaic	Investment cost	3000	CNY/kW
Methane synthesis equipment	Investment cost	4800	CNY/kW
Hydrogen storage equipment	Investment cost	2880	CNY/kgH ₂
Carbon storage equipment	Investment cost	234	CNY/kgCO ₂
Cost/Sale price	Fuel cost	400	CNY/tce
	Water price	4.5	CNY/t
	Electricity price	0.35	CNY/kWh
	Carbon capture tax credit revenue	210	CNY/tCO ₂
	Methane sales price	4	CNY/m ³

Table 9. Relevant tax rate parameters within IEPU [51–54].

Name of Tax Rate	Value
VAT rate for electricity and fuel	13%
VAT rate for methane	9%
VAT rate for water fee	13%
VAT rate for sale of carbon assets	6%
VAT surcharge	10%
Revenue tax rate	25%

6.2.2. Economic Assessment Results

The financial indicators of the IEPU retrofit project under the synthetic methane technology route are shown in Table 10. According to the standards for economic evaluation of construction projects in China [55], the benchmark rate of return on basic investment in the energy industry is 8%.

Table 10. Financial indicators of IEPU retrofit project.

Financial Indicators	Value ($\times 10^4$ CNY)
Initial investment cost	256,840.2
Annual O&M cost	14,471.85
Annual fuel cost	29,328
Annual water fee cost	2075.46
Annual average total cost	66,444.93
Annual power supply revenue	45,745
Annual methane sale revenue	34,300
Annual carbon capture tax credit revenue	8358
Annual average revenue	88,403
NPV ($i = 8\%$) [55]	57,807.61
IRR(%)	11.21
Static investment pay-back period (Year)	8.38
Discounted investment pay-back period (Year)	13.64

Based on the relevant financial indicators obtained through calculation, under the electricity-to-methane technology route, the internal rate of return of the project is 11.21%, which is higher than the benchmark discount rate, and the NPV is 578.08 million CNY. The investment can be recovered within the life-cycle of the project. The results indicate that the project is economically feasible. The composition of the investment and annualized cost indicators for the IEPU retrofit project under this technology route is shown in Figures 10 and 11. From the perspective of investment composition, the initial investment mainly focuses on distributed photovoltaic, carbon capture, and electrolysis hydrogen production equipment, which together account for over 90% of the total. In contrast, the methane synthesis, hydrogen storage, and carbon storage devices have relatively low investment due to their mature technology and scale effect. In terms of various annualized economic indicators, the annualized fixed costs mainly include equipment operation and maintenance costs and depreciation costs, accounting for approximately 51.1%; the annualized variable costs mainly include coal-fired costs and water fees, accounting for 48.9%. The revenue end presents a diversified structure, with the electricity sales revenue accounting for the highest proportion, followed by the methane sales revenue, and the carbon capture rebate revenue, as a policy incentive, also contributes a certain proportion. This revenue composition reflects the dual value of the project in the power market and the green fuel market. Its economic performance is expected to further improve with the improvement of the carbon market mechanism.

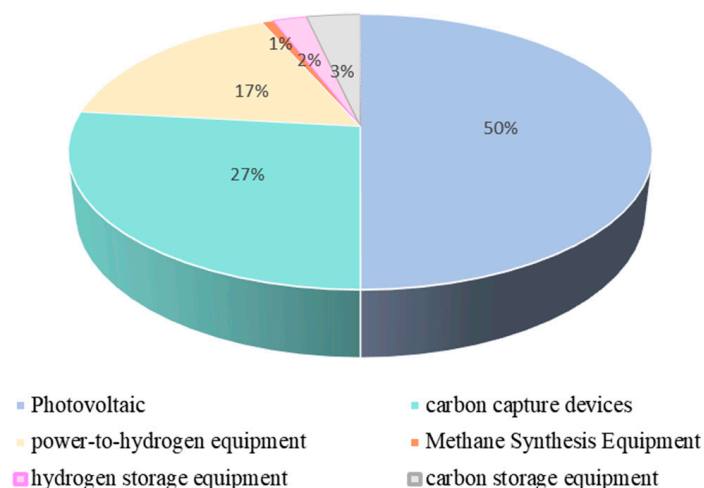


Figure 10. The initial investment composition of IEPU system.

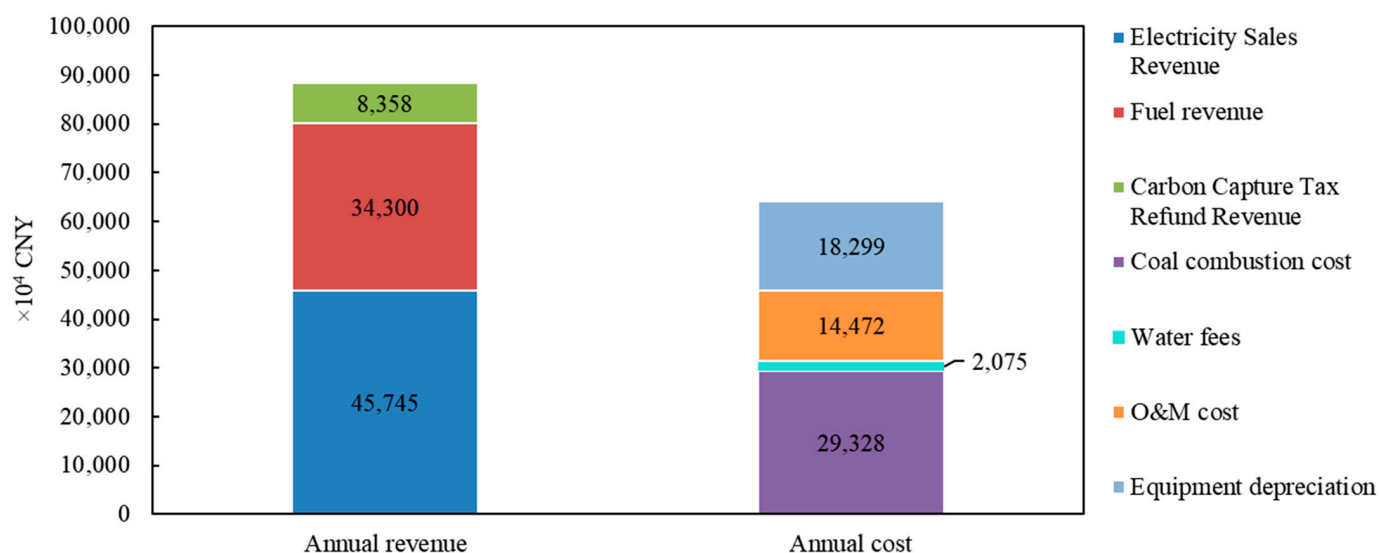


Figure 11. Composition of annualized economic indicators in IEPU.

6.2.3. Sensitivity Analysis

In the economic assessment of the integrated energy production unit retrofit project, conducting a sensitivity analysis on key parameters such as the feed-in tariff, methane sales price, carbon capture tax credit revenue, and coal price holds significant decision-making value. These factors essentially constitute the core economic cash drivers of the project: fluctuations in the feed-in tariff significantly affect the project's cash flow; methane price, as the main product, determines the revenue base; the carbon capture tax credit revenue reflects the level of policy support and represents a key green premium; coal price, as an important cost factor, directly relates to the fuel cost in the production process. Therefore, it is necessary to conduct sensitivity analysis on these factors and calculate the impact of every single factor's fluctuation within the range of -10% to 10% on the project NPV. The analysis results are shown in Figure 12.

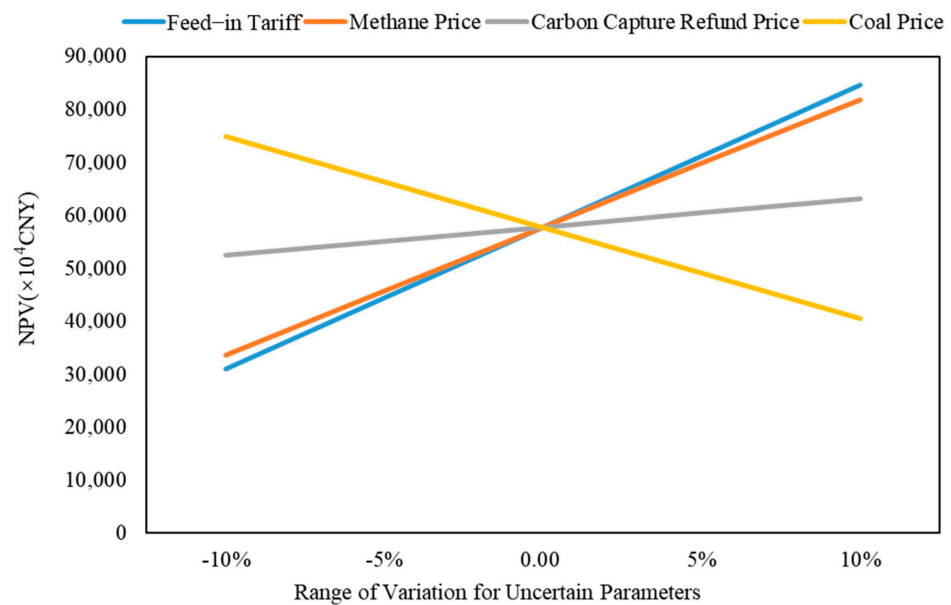


Figure 12. NPV sensitivity for the IEPU project.

The calculation results show that the NPV of the IEPU retrofit project under the power-to-methane technology route is highly sensitive to the grid electricity price, followed by the methane price and the coal price. The impact of the carbon capture rebate price on the project NPV is relatively small. With the continuous technology advancements, the investment costs of core equipment such as electric hydrogen production, hydrogen storage, and carbon storage in the IEPU system will decrease. Therefore, the economic benefits of the IEPU system will further improve.

6.3. Investment Risk Analysis Based on Interval Numbers

Based on the interval number theory, this section quantifies the investment risks of the IEPU retrofit project under the fluctuations of key economic parameters. By combining the aforementioned risk identification and sensitivity analysis, four parameters with high uncertainties and significant impacts on the project economics are determined as the core risk variables: the feed-in tariff, methane price, carbon price, and initial investment. The electricity price is a comprehensive reference to the electricity prices of most regions across China, and is set as [0.3, 0.4] CNY/kWh. The methane price is based on the benchmark methane price of most regions of China [56], considering the effect of raw material procurement scale and regional price differences, and is set as [3.8, 4.2] CNY/m³. The carbon price is set according to a volatility rate of 14% [37]. The initial investment is set based on a 4.79% fluctuation [49]. The investment risk evaluation results are shown in Table 11.

Table 11. Investment risk assessment results.

Indicator	Range Value	Unit
Electricity price	[0.3, 0.4]	CNY/kWh
Methane price	[3.8, 4.2]	CNY/m ³
Carbon price	[180, 239]	CNY/ton CO ₂
Initial investment	[244,537.6, 269,142.8]	10 ⁴ CNY
NPV (i = 8%)	[−12,083.03, 125,096.44]	10 ⁴ CNY
IRR	[7.31, 15.01]	%
Discounted investment payback period	[9.23, 21.63]	years

The interval number risk assessment results reveal that the economic feasibility of the preferred technical route has significant conditional sensitivity on external market parameters. The project's profitability exhibits a wide possible range, with the I-NPV ranging from −120.83 to 1250.96 million CNY, the I-IRR ranging from 7.31% to 15.01%, and the I-PP from 9.23 to 21.63 years. The analysis shows that the feed-in tariff and methane price are the predominant risk drivers, exerting the strongest influence on project returns.

From an investment attractiveness perspective under uncertainty, the project demonstrates robust potential. The upper-bound values of I-IRR (15.01%) and I-NPV (1250.96 million CNY) indicate substantial upside potential under favorable market conditions. More importantly, the downside risks reflected in the lower-bound values are relatively limited: even under reasonably adverse scenarios, the I-IRR lower bound of 7.31% is only slightly below the commonly accepted benchmark and can be effectively mitigated through proactive risk management. By establishing long-term power purchase agreements and utilizing market hedging instruments to stabilize electricity, product, and carbon prices, the volatility of returns can be significantly reduced. These measures narrow the risk range, ensuring that the project remains resilient even under adverse scenarios.

Consequently, while the project's returns are subject to external uncertainties, its risk-adjusted investment attractiveness remains strong. The combination of favorable baseline economics and manageable downside exposure positions the project as a viable and appealing investment opportunity in the evolving low-carbon energy landscape.

7. Conclusions

This study constructs a comprehensive decision-making framework integrating “technology selection—economic analysis—risk assessment” to support the selection of P2X routes for IEPU retrofits. A systematic analysis is conducted on the electrolytic hydrogen production and hydrogen utilization stages, along with the application of life-cycle economic analysis coupled with interval number-based risk assessment. Through the evaluation and analysis of a 600 MW retrofit case, the following conclusions can be drawn:

- (1) For electrolytic hydrogen production, AWE technology exhibits superior economic viability in large-scale commercial applications. Its LCOH is approximately 22.8% lower than that of PEM electrolysis and 45.7% lower than that of SOEC electrolysis. This advantage is attributable to lower initial investment, a mature supply chain, and reduced operating costs. Under current technological and economic constraints, AWE is a more suitable choice for large-scale integration within IEPU systems.
- (2) In terms of hydrogen utilization, the methanation route shows the highest economic returns. It generates the greatest revenue per unit of hydrogen converted, outperforming methanol and green ammonia synthesis. This economic edge is largely attributed to the higher market value of green methane and the additional revenue stream from carbon capture.
- (3) The integrated “AWE + methanation” route is economically viable for renovating a 600 MW coal-fired unit in IEPU. Coupled with advancing “dual-carbon” policy, declining renewable power costs, and a maturing hydrogen market, this retrofit is expected to substantially enhance its future profitability.
- (4) The interval number-based risk assessment reveals that the project's economic feasibility is significantly sensitive to fluctuations in key parameters such as the feed-in tariff and methane prices. Favorable levels of these can yield substantial returns while adverse shifts may lead to sub-benchmark performance or financial losses. Therefore, implementing corresponding risk hedging and management mechanisms is crucial.

However, the proposed methodology in this paper also has some limitations, which we aim to resolve in future studies. Chiefly, the current analysis focuses solely on the

external sale of hydrogen-based products and does not consider their potential internal utilization within the IEPU system, such as on-site co-firing of green ammonia in retrofitted coal-fired units. Future work should investigate routes to systematically evaluate the synergistic effects on overall system efficiency, economic performance, and deep-decarbonization potential.

Author Contributions: Conceptualization, Y.Y. and Y.W.; methodology, Y.Y., Y.W. and Q.L.; validation, Y.W., Q.L. and J.Y.; formal analysis, Y.W., Q.L. and J.Y.; investigation, Y.W. and Q.L.; resources, Y.Y. and M.T.; data curation, Q.L. and J.Y.; writing—original draft preparation, Y.W. and Y.Y.; writing—review and editing, Y.Y., Y.W. and Q.L.; visualization, J.Y. and M.T.; supervision, Y.Y.; project administration, Y.Y. and Y.W.; funding acquisition, Y.W. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by the Social Science Foundation of Hebei Province, grant number HB22GL064; the Fundamental Research Funds for the Central Universities, grant number 2025MS167.

Data Availability Statement: The original contributions presented in this study are included in the article. Further inquiries can be directed to the corresponding author.

Conflicts of Interest: Author Yani Yang was employed by the company Hainan Electric Power Co., Ltd. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

Abbreviations

The following abbreviations are used in this manuscript:

P2X	Power-to-X
IEPU	Integrated Energy Production Unit
AWE	Alkaline Water Electrolysis
PEM	Proton Exchange Membrane
SOEC	Solid Oxide Electrolyzer Cell
AEM	Anion Exchange Membrane
CCUS	Carbon Capture, Utilization, and Storage
CCU	Carbon Capture and Utilization
HB	Haber-Bosch
LCOH	Levelized Cost of Hydrogen
NPV	Net Present Value
IRR	Internal Rate of Return
VAT	Value-Added Tax
CCER	Chinese Certified Emissions Reductions
I-NPV	Interval Net Present Value
I-IRR	Interval Internal Rate of Return
I-PP	Interval Discounted Payback Period

Appendix A

Table A1. X technology selection and IEPU economic analysis.

Name	Value	Unit	Ref.	Year
AWE equipment investment cost	2000	CNY/kW	[31]	2025
PEM equipment investment cost	7196	CNY/kW	[31]	2025
SOEC equipment investment cost	19,600	CNY/kW	[32]	2024
Methane synthesis equipment investment cost	4800	CNY/kW	[8]	2024
Methanol synthesis equipment investment cost	4000	CNY/kW	[37]	2025
Ammonia synthesis plant investment cost	4111	CNY/ton	[44]	2025

Table A1. Cont.

Name	Value	Unit	Ref.	Year
Carbon capture device investment cost	68,767	$\times 10^4$ CNY	[8]	2024
Photovoltaic investment cost	3000	CNY/kW	[38]	2024
Hydrogen storage equipment investment cost	2880	CNY/kgH ₂	[47]	2025
Carbon storage equipment Investment cost	234	CNY/kgCO ₂	[47]	2025
Fuel cost	400	CNY/tce	[50]	2025
Electricity cost	0.2	CNY/kWh	[38]	2025
Industrial water cost	4.33	CNY/t	[36]	2024
KOH cost	5.7	CNY/kg	[39]	2025
Electricity sale price	0.35	CNY/kWh	[35]	2025
Methane price	4	CNY/Nm ³	[43]	2025
Methanol price	2.2	CNY/kg	[45]	2024
Ammonia price	2.4	CNY/kg	[44]	2025
Carbon capture tax credit revenue	210	CNY/tCO ₂	[47]	2025

References

- Li, T.; Li, Y.; Han, X.; Fan, X. The transaction solution in coupled energy-frequency market mechanism considering multi-agent integrated energy production unit. *Sustain. Energy Technol. Assess.* **2025**, *78*, 104347. [\[CrossRef\]](#)
- Nie, H.; Ye, W.; Mo, J. Research on China's Energy Transition Development Strategy for the 15th Five-Year Plan Period. *Henan Soc. Sci.* **2025**, *33*, 1–9.
- Cui, Y.; Xu, Y.; Zhang, J.; Wang, M.; Fu, X. Stochastic Low-carbon Scheduling Strategy of Integrated Energy Production Unit Considering Solar-assisted Carbon Capture Technology. *Proc. CSEE* **2024**, *44*, 5574–5588. [\[CrossRef\]](#)
- Li, Y.; Li, Z. A novel risk-averse multi-energy Management for Effective Offering Strategy of integrated energy production units in a real-time electricity market. *Appl. Energy* **2025**, *377*, 124380. [\[CrossRef\]](#)
- Lu, Z.; Xiong, J.; Wang, T.; Kang, Y.; Li, Y.; Zhuo, J. Source-Load Synergistic Optimization Of Integrated Energy systems Considering Dynamic Hydrogen Blending and Flexible Carbon Capture. *Acta Energiæ Solaris Sin.* **2025**, *46*, 82–92. [\[CrossRef\]](#)
- Lystbaek, N.; Gregersen, M.; Shaker, H.R. Review of Energy Portfolio Optimization in Energy Markets Considering Flexibility of Power-to-X. *Sustainability* **2023**, *15*, 4422. [\[CrossRef\]](#)
- Li, Q.; He, M.; Tang, X.; Lee, W.-J.; Zhang, Z. Capacity Configuration in Integrated Energy Production Unit Considering Ladder-Type Carbon Trading Under CCER Quota. *IEEE Trans. Ind. Appl.* **2025**, *61*, 884–894. [\[CrossRef\]](#)
- Yu, Q.; Zhang, Y.; Zhao, Q.; Sun, L. Life-cycle Carbon Footprint Assessment and Techno-economic Analysis of Integrated Energy Production Unit. *Proc. CSEE* **2024**, *44*, 3115–3125. [\[CrossRef\]](#)
- Zhang, N.; Pang, J.; Wen, J.; Wang, J. The Economic Impact of Abolishing Electricity Price Subsidies in China—An Analysis Based on Electricity Price Regulation and Perfectly Competitive Markets. *China Environ. Sci.* **2022**, *42*, 2442–2452. [\[CrossRef\]](#)
- Csedo, Z.; Sinoros-Szabo, B.; Zavarko, M. Seasonal Energy Storage Potential Assessment of WWTPs with Power-to-Methane Technology. *Energies* **2020**, *13*, 4973. [\[CrossRef\]](#)
- Rashid, M.M.; Mesfer, M.K.A.; Naseem, H.; Danish, M. Hydrogen Production by Water Electrolysis: A Review of Alkaline Water Electrolysis, PEM Water Electrolysis and High Temperature Water Electrolysis. *Int. J. Eng. Adv. Technol.* **2015**, *4*, 2249–8958.
- Zang, G.; Sun, P.; Elgowainy, A.; Wang, M. Technoeconomic and Life Cycle Analysis of Synthetic Methanol Production from Hydrogen and Industrial Byproduct CO₂. *Environ. Sci. Technol.* **2021**, *55*, 5248–5257. [\[CrossRef\]](#)
- Raihan, A. Carbon capture, utilization, and storage (CCUS) in the context of earth energy systems: A multidisciplinary review. *Geosci. Front.* **2025**, *16*, 102177. [\[CrossRef\]](#)
- Liu, F.; Lv, T.; Meng, Y.; Hou, X.; Xu, J.; Deng, X. Low-Carbon Transition Paths of Coal Power in China's Provinces under the Context of the Carbon Trading Scheme. *Sustainability* **2022**, *14*, 9657. [\[CrossRef\]](#)
- Kumar, L.; Sleiti, A.K.; Hassan, I.; Rezaei-Gomari, S.; Azizur Rahman, M. Thermo-economic analysis of a novel P2X polygeneration system for hydrogen, ammonia, and methanol production with near-zero emissions. *Int. J. Hydrogen Energy* **2025**, *150*, 150201. [\[CrossRef\]](#)
- Guo, X.; Liao, Y.; Han, Y.; Ma, X. Plant Capacity Optimization of Integrated Energy Production Units (IEPU) Considering a Complete Process Technology Portfolio. In *Proceedings of the 2023 6th International Conference on Energy, Electrical and Power Engineering (CEEPE), Guangzhou, China, 12–14 May 2023*; IEEE: Piscataway, NJ, USA, 2023; pp. 1284–1288.
- Horri, B.A.; Ozcan, H. Green hydrogen production by water electrolysis: Current status and challenges. *Curr. Opin. Green Sustain. Chem.* **2024**, *47*, 100932. [\[CrossRef\]](#)

18. Sebbahi, S.; Assila, A.; Belghiti, A.A.; Laasri, S.; Kaya, S.; Hlil, E.K.; Rachidi, S.; Hajjaji, A. A comprehensive review of recent advances in alkaline water electrolysis for hydrogen production. *Int. J. Hydrogen Energy* **2024**, *82*, 583–599. [\[CrossRef\]](#)
19. Guo, X.; Li, X.; Xu, Z.; He, G.; Miu, P. Cost analysis of hydrogen production by electrolysis of renewable energy. *Energy Storage Sci. Technol.* **2020**, *9*, 688–695. [\[CrossRef\]](#)
20. Yang, W.; Hu, Y.; Guo, B.; Zhu, W.; Xie, C.; You, L.; Xiong, L.; Zhang, L. Adaptive operation strategy for wind-hydrogen systems integrating alkaline and proton exchange membrane electrolyzers. *Energy* **2025**, *337*, 138607. [\[CrossRef\]](#)
21. Zhang, J. Current Status of Hydrogen Energy Technology Development in China. *Boil. Manuf.* **2025**, 56–58.
22. Yang, X.; Yao, M.; Han, W.; Feng, P.; Zhang, K. Review on current status and development of large-scale renewable energy electrolysis hydrogen production technology. *Therm. Power Gener.* **2025**, *54*, 33–43. [\[CrossRef\]](#)
23. Calise, F.; Capiello, F.L.; Cimmino, L.; Cutolo, L.; Vicidomini, M. Thermo-economic Comparison of Alkaline, Solid Oxide and Anion Exchange Membrane Electrolyzers for Power-to-Gas Applications. *Renew. Sustain. Energy Rev.* **2025**, *224*, 116115. [\[CrossRef\]](#)
24. Wei, X.; Sharma, S.; Waeber, A.; Wen, D.; Sampathkumar, S.N.; Margni, M.; Marechal, F.; Van Herle, J. Comparative life cycle analysis of electrolyzer technologies for hydrogen production: Manufacturing and operations. *Joule* **2024**, *8*, 3347–3372. [\[CrossRef\]](#)
25. Bos, M.J.; Kersten, S.R.A.; Brilman, D.W.F. Wind power to methanol: Renewable methanol production using electricity, electrolysis of water and CO₂ air capture. *Appl. Energy* **2020**, *264*, 114672. [\[CrossRef\]](#)
26. Ye, J.; Zhang, Y.; Hao, Y.; Lee, K.Y.; Sun, L. Configuration optimization and techno-economic analysis of integrated energy production unit of methane and methanol. *Sustain. Energy Technol. Assess.* **2024**, *69*, 103902. [\[CrossRef\]](#)
27. Beckmann, J.; Klöckner, K.; Letmathe, P. The role of power-to-X and domestic eFuel production for energy transition and energy independence in Europe. *J. Clean. Prod.* **2025**, *492*, 144807. [\[CrossRef\]](#)
28. Klyapovskiy, S.; Zheng, Y.; You, S.; Bindner, H.W. Optimal operation of the hydrogen-based energy management system with P2X demand response and ammonia plant. *Appl. Energy* **2021**, *304*, 117559. [\[CrossRef\]](#)
29. Zhou, X.; Zhao, Q.; Zhang, Y.; Sun, L. Integrated energy production unit: An innovative concept and design for energy transition toward low-carbon development. *CSEE J. Power Energy Syst.* **2021**, *7*, 1133–1139. [\[CrossRef\]](#)
30. Zhou, X.; Zhao, Q.; Zhang, Y.; Yang, H. Analysis of the Development Trend of China's Energy and Power System Under the Dual Carbon Target: Green Electricity Substitution and Green Hydrogen Substitution. *Proc. CSEE* **2024**, *44*, 6707–6721. [\[CrossRef\]](#)
31. Liu, L.; Zhang, H.; Wang, Q.; Zhang, Y.; Baldinelli, A.; Sun, M.; Nian, X.; Duan, L.; Desideri, U. Techno-economic performance optimization and energy integration analysis of ammonia synthesis system with different electrolyzers. *Energy Convers. Manag.* **2025**, *343*, 120180. [\[CrossRef\]](#)
32. Chen, Z. System Integration and Techno-Economic Evaluation of a Process Coupling Renewable Energy Water Electrolysis for Hydrogen Production with Ammonia Synthesis. Master's Thesis, Lanzhou University of Technology, Lanzhou, China, 2024.
33. Bojarska, Z.; Karnas, M.J.; Godula-Jopek, A.; Mandrek, S.; Makowski, Ł. Simultaneous hydrogen generation and organic oxidation in low-temperature electrolyzers. *Appl. Energy* **2025**, *389*, 125697. [\[CrossRef\]](#)
34. Makhsoos, A.; Kandidayeni, M.; Boulon, L.; Pollet, B.G. A comparative analysis of single and modular proton exchange membrane water electrolyzers for green hydrogen production—A case study in Trois-Rivières. *Energy* **2023**, *282*, 128911. [\[CrossRef\]](#)
35. Notice from the Jiangsu Provincial Development and Reform Commission Regarding Matters Pertaining to the Implementation of Competitive Bidding for Mechanism Tariffs for New Energy Incremental Projects for the 2025–2026 Period. 2025. Available online: https://fzggw.jiangsu.gov.cn/art/2025/11/21/art_51012_11695023.html (accessed on 11 November 2025).
36. Sanya Municipal Development and Reform Commission Policy Interpretation Regarding the Adjustment of Sanya's Tap Water Tariffs. Available online: <https://fg.sanya.gov.cn/fgwsite/zcjd/202405/d0720990e0564282a813d7f6c9d1b487.shtml> (accessed on 20 May 2024).
37. Nie, P.; Gao, Z.; Wang, X. Research on CCUS investment decisions for coal-fired power plants based on real options theory. *Clean Coal Technol.* **2025**, *31*, 1–8. [\[CrossRef\]](#)
38. Wang, C.; Gao, X.; Chen, H.; Gui, F.; Zhang, G.; Zhang, K. Comprehensive cost-benefit analysis of photovoltaic power grid parity in various regions of China. *Renew. Energy Resour.* **2024**, *42*, 1295–1301. [\[CrossRef\]](#)
39. China Coal Market Network. 2025. Available online: <https://www.cctd.com.cn/index.php?m=content&c=index&a=lists&catid=454&data=CCTD%C7%D8%BB%CA%B5%BA%B6%AF%C1%A6%C3%BA%BC%DB%B8%F1&name=CCTD%C7%D8%BB%CA%B5%BA%B6%AF%C1%A6%C3%BA%BC%DB%B8%F1> (accessed on 1 March 2026).
40. Salt Lake Information Network. 2025. Available online: <https://yhzx.com/details?id=8008> (accessed on 4 February 2026).
41. Yang, J.; Lam, T.Y.; Luo, Z.; Cheng, Q.; Wang, G.; Yao, H. Renewable energy driven electrolysis of water for hydrogen production, storage, and transportation. *Renew. Sustain. Energy Rev.* **2025**, *218*, 115804. [\[CrossRef\]](#)
42. Thepsaskul, W.; Wongsapai, W.; Jaitiang, T.; Jaekhajad, P. Prospects of Attaining Thailand's Carbon Neutrality Target Through Carbon Capture and Storage by Public Power Utility. *Sustainability* **2025**, *17*, 276. [\[CrossRef\]](#)

43. Wang, Y.; Shao, S.; Gao, Q.; Zhang, Y.; Wang, X.; Gao, X. Life cycle environmental impact and economic analysis of post-combustion carbon capture technologies in supercritical coal-fired power plants. *Environ. Impact Assess. Rev.* **2025**, *114*, 107933. [CrossRef]
44. Aminaho, E.N.; Aminaho, N.S.; Aminaho, F. Techno-economic assessments of electrolyzers for hydrogen production. *Appl. Energy* **2025**, *399*, 126515. [CrossRef]
45. Ge, S.; Yang, Z.; Bai, J.; Ding, Y.; Wen, J.; Li, X. Development Status and Prospect of Hydrogen Production Technology by Renewable Energy and Its Main Equipment. *J. Taiyuan Univ. Technol.* **2024**, *55*, 759–787. [CrossRef]
46. Herraiz, L.; Lucquiaud, M.; Chalmers, H.; Gibbins, J. Sequential Combustion in Steam Methane Reformers for Hydrogen and Power Production With CCUS in Decarbonized Industrial Clusters. *Front. Energy Res.* **2020**, *8*, 180. [CrossRef]
47. Dincă, C.; Slavu, N. Integrating Power-to-Methane with Carbon Capture (P2M-CC) for Sustainable Decarbonization in Cement Manufacturing. *Energies* **2025**, *18*, 777. [CrossRef]
48. Zuo, F.; Zhang, Y.; Zhao, Q.; Sun, L. Two-stage Stochastic Optimization for Operation Scheduling and Capacity Allocation of Integrated Energy Production Unit Considering Supply and Demand Uncertainty. *Proc. CSEE* **2022**, *42*, 8205–8215. [CrossRef]
49. Thom, D.; Bugała, A.; Bugała, D.; Czekala, W. Comprehensive Energy and Economic Analysis of Selected Variants of a Large-Scale Photovoltaic Power Plant in a Temperate Climate. *Energies* **2025**, *18*, 4198. [CrossRef]
50. Ma, D.; Wen, X.; Wen, Z.; Wu, H.; Ding, S.; Li, W.; Liu, P. Technology and economic analysis on green methanol production from biomass. *Mod. Chem. Ind.* **2025**, *45*, 250–255. [CrossRef]
51. Value Added Tax Law of the People's Republic of China. Available online: <https://fgk.chinatax.gov.cn/zcfgk/c100009/c5237365/content.html> (accessed on 25 February 2024).
52. Law of the People's Republic of China on Urban Maintenance and Construction Tax. Available online: https://www.mof.gov.cn/zhengwuxinxi/caizhengxinwen/202008/t20200812_3566258.htm (accessed on 12 August 2020).
53. Decision of the State Council on Amending the Provisional Regulations on the Collection of Education Surcharge. 28 March 2008. Available online: https://www.gov.cn/gongbao/content/2011/content_1860811.htm (accessed on 8 January 2011).
54. Enterprise Income Tax Law of the People's Republic of China. 29 December 2018. Available online: <https://www.lawinfochina.com/display.aspx?id=29721&lib=law&EncodingName=big5> (accessed on 29 December 2018).
55. Notice of the National Development and Reform Commission and the Ministry of Construction on Issuing the Economic Evaluation Methods and Parameters for Construction Projects. 2006. Available online: <https://manage.gsei.com.cn/html/1338/2006-10-23/content-41693.html> (accessed on 23 October 2006).
56. Notice Regarding Adjustments to the Benchmark Price for Non-Residential Natural Gas Sales in This Municipality. Available online: <https://www.shanghai.gov.cn/gwk/search/content/e57a04a91ec64dd7b153e4ea4304dbdc> (accessed on 26 February 2026).

Disclaimer/Publisher's Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.