

# Technical and Financial Feasibility Analysis of Hydrogen Production from Palm Oil Mill Effluent Biogas for Fuel Cells in Supporting Energy System Stabilization from Intermittent Power Supply Fluctuations

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Received 12 June 2025; Received in revised form 14 October 2025

Accepted 14 October 2025; Available online 27 March 2026

## ABSTRACT

Hydrogen production from Palm Oil Mill Effluent (POME) biogas via Dry Methane Reforming (DMR), integrated with a Proton Exchange Membrane Fuel Cell (PEMFC), presents a technically and economically viable solution to enhance voltage stability in Indonesia's 20 kV distribution networks. Process simulation using Aspen HYSYS yielded 1,085 kg/h of hydrogen, stored in three spherical tanks (16.2 m diameter each), and used to power a 2.115 MW PEMFC system with 33.76% electrical efficiency. Grid analysis using PSS® Sincal demonstrated improved voltage levels from 12.51–19.67 kV to 19.5–22.16 kV, eliminating undervoltage and reducing reliance on the 150 kV grid. Economically, the system achieves a revenue-to-cost ratio of 2.42, supported by annual hydrogen revenue of USD 19.05 million and diesel backup cost savings of USD 7.88 million. Financial metrics confirm project viability with a Net Present Value (NPV) of USD 49.58 million, an Internal Rate of Return (IRR) of 53.61%, a payback period of 2.7 years, and a Benefit-Cost Ratio (B/C) of 2.8. The integrated system supports Indonesia's national targets for 23% renewable energy by 2025 and a 29% GHG emission reduction by 2030.

**Keywords:** Dry methane reforming; Grid stability; Hydrogen; PEM fuel cell; Techno-economic feasibility

## 1. Introduction

The energy sector is a major contributor to greenhouse gas (GHG) emissions in Indonesia, posing a significant challenge to the nation's efforts in achieving its emission reduction targets. As part of its commitment to climate change mitigation, Indonesia has set a renewable energy mix target of 23% by 2025 and a GHG reduction of 29% by 2030 [1]. Biomass, especially from the palm oil industry, presents an abundant and underutilized resource that can support these national goals. Palm Oil Mill Effluent (POME), a byproduct of crude palm oil production, is a significant source of methane ( $\text{CH}_4$ ) emissions if left untreated.

Indonesia is the world's largest producer of palm oil, generating approximately 42.5 million metric tons of crude palm oil (CPO) in 2019. This production volume generates substantial liquid waste known as Palm Oil Mill Effluent (POME), which holds significant potential as a renewable energy resource. For every ton of CPO produced, 2.5–3.37 tons of POME are discharged, depending on mill capacity and process efficiency. If left untreated, POME decomposition results in high greenhouse gas (GHG) emissions, particularly methane ( $\text{CH}_4$ ), contributing an estimated 12.4 million tons of  $\text{CO}_2$ -equivalent per year—about one-third of the total emissions from Indonesia's palm oil industry.

Through anaerobic digestion, POME can be effectively converted into biogas containing 50–75% methane and 25–45% carbon dioxide, with a yield of approximately 25.6  $\text{Nm}^3$  of biogas per cubic meter of POME. This biogas can be harnessed as a renewable energy source for power generation, capable of producing around 2.1 kWh per  $\text{Nm}^3$  of biogas, or upgraded into bio-compressed natural gas (bio-CNG) for transportation fuel [2]. Moreover, utilizing

POME-derived biogas helps reduce GHG emissions and supports Indonesia's national target to cut overall emissions by 29% by 2030, as outlined in the country's energy transition roadmap [1].

Regionally, POME production is concentrated in Sumatra and Kalimantan, where most palm oil mills are located. However, seasonal variations in palm fruit harvesting cause fluctuations in feedstock availability, typically around 10–25% between peak and off-peak seasons. To ensure consistent hydrogen production, this study proposes several mitigation strategies: (1) securing long-term feedstock supply contracts with palm oil mill operators, (2) aggregating biogas from multiple nearby mills to stabilize feedstock flow, and (3) incorporating short-term biogas storage or hybridizing with alternative biomass sources to maintain operational continuity.

These measures are essential to ensure feedstock reliability for hydrogen production via Dry Methane Reforming (DMR). Furthermore, the utilization of POME aligns with Indonesia's sustainable energy strategy and circular economy principles, transforming an industrial waste stream into a valuable energy carrier that contributes to decarbonization and grid stability [1, 2].

The high organic content of POME makes it suitable for anaerobic digestion, producing biogas with up to 75% methane [2]. One promising avenue for the valorization of POME biogas is through Dry Methane Reforming (DMR), a catalytic process that converts  $\text{CH}_4$  and  $\text{CO}_2$ —both potent GHGs—into synthesis gas (syngas), particularly hydrogen ( $\text{H}_2$ ) and carbon monoxide ( $\text{CO}$ ) [3, 4]. Hydrogen, as a clean energy carrier, can be utilized in fuel cells such as Proton Exchange Membrane Fuel Cells (PEMFC), which generate electricity

with water as the only emission. Integration of hydrogen-based fuel cells in electrical distribution systems offers a dual benefit: improving power quality and reducing dependency on fossil-based generation, particularly during peak load or renewable energy fluctuation [5].

Integration of hydrogen-based fuel cells in electrical distribution systems offers a dual benefit: improving power quality and reducing dependency on fossil-based generation, particularly during peak load or renewable energy fluctuation [5]. The hydrogen produced is utilized in Proton Exchange Membrane Fuel Cells (PEMFC) to generate clean electricity. Previous studies have focused on optimizing hydrogen production from biomass [6] or modeling fuel cell performance [7], but rarely address the integration of hydrogen systems for stabilizing renewable-dominant power grids. This research bridges that gap by proposing a novel system that simulates hydrogen production from POME biogas via DMR and integrates it with PEMFCs to mitigate power quality fluctuations in a 20 kV distribution grid. Therefore, the objective of this research is to design and simulate a hydrogen production process from POME-derived biogas and assess the technical feasibility of integrating hydrogen-fed PEMFCs into the grid to enhance voltage stability. The novelty of this study lies in its combined approach—utilizing waste-derived biogas, advanced reforming technology, and real-time grid modeling—to address renewable intermittency and decarbonize the energy sector simultaneously.

## 2. Materials and Methods

### 2.1 Materials and software tools

This research employed a simulation-based approach encompassing process modeling, electrical grid analysis,

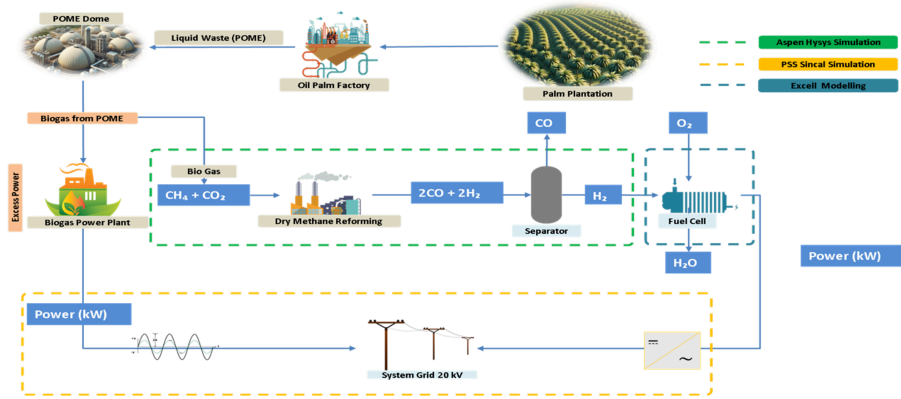
and economic evaluation. The primary feedstock is biogas derived from Palm Oil Mill Effluent (POME), an abundant organic waste generated by the palm oil industry. POME contains high levels of methane (50–75%) and carbon dioxide (25–45%), making it suitable for bioenergy applications [1].

Three software platforms were used to carry out the simulations. Aspen HYSYS was employed to model the thermodynamic and chemical behavior of the hydrogen production process via Dry Methane Reforming (DMR). PSS®Sincal was used to simulate the impact of fuel cell integration on voltage stability in a 20 kV electrical distribution grid. Additionally, Microsoft Excel was used for fuel cell modelling and economic analysis, including calculations for NPV, IRR, Payback Period, and B/C Ratio.

### 2.2 Research design and scheme

The schematic flow of this study is shown in Fig. 1, which illustrates the conversion pathway from palm oil plantation waste to grid power compensation. Liquid POME is first processed in a biodome to produce biogas, which is partly used in a biogas power plant and partly routed into the DMR system. The reforming unit converts  $\text{CH}_4$  and  $\text{CO}_2$  into  $\text{H}_2$  and  $\text{CO}$ , where  $\text{H}_2$  is then separated and stored.

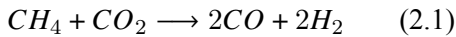
This hydrogen is fed into a PEMFC system, which reacts with  $\text{O}_2$  from air to generate electricity and  $\text{H}_2\text{O}$  as a byproduct. The produced power is injected into the 20 kV grid to mitigate voltage fluctuation caused by intermittent renewable sources. Aspen HYSYS is used for process simulation, PSS Sincal for grid integration analysis, and Excel modeling for economic evaluation.



**Fig. 1.** Research schematic of hydrogen production and grid integration system. POME-derived biogas undergoes anaerobic digestion, reforming in a Ni/Al<sub>2</sub>O<sub>3</sub>-based DMR reactor to produce hydrogen, which is stored and utilized in a PEMFC for voltage stabilization in the 20 kV distribution grid.

### 2.3 Simulation procedure

The research procedure began with the simulation of hydrogen production. The DMR process was modeled with the primary reaction:



To describe the reaction kinetics, the rate of reaction for DMR can be formulated as:

$$r = k = (2.3 \times 10)^{23}(-155.33/RT), \quad (2.2)$$

where  $k(T)$  is the reaction rate constant (units depend on rate law used; here treated as first-order equivalent for modeling convenience, mol·m<sup>-2</sup>·s<sup>-1</sup> for surface reaction rate);  $A = 2.13 \times 10^{13}$ ;  $E_a = 155.353 \text{ kJ} \cdot \text{mol}^{-1}$ ;  $R = 8.314 \text{ J} \cdot \text{mol}^{-1} \cdot \text{K}^{-1}$ ;  $T$  is absolute temperature (K).

Hydrogen was used as a fuel in a Proton Exchange Membrane Fuel Cell (PEMFC) system to generate electricity. The total electrical power produced was calculated using the following equation [8]:

$$P_{Electric} = U_{Stack} \times I$$

$$= \text{Average Cell} \times N \times I, \quad (2.3)$$

where  $P_{Electric}$  is total stack electrical power (W);  $U_{Stack}$  is stack voltage (V);  $I_{Stack}$  is stack current (A);  $N_{cell}$  is a number of cells in the stack;  $E_{cell,avg}$  is an average cell voltage (V; includes activation, ohmic and concentration losses).

Power system modeling using PSS® Sincal assessed the performance of the 20 kV grid before and after fuel cell integration. Key indicators included minimum and maximum voltage, undervoltage occurrences, and overall power quality. The PEMFC was modeled as a voltage-supporting distributed generation (DG) unit activated under peak and critical load conditions, following approaches by [5]. To assess the economic feasibility of the proposed system, standard investment appraisal methods were applied. The Net Present Value (NPV) was calculated to determine the present worth of net cash flows over the project lifetime, considering a specific discount rate. A positive NPV indicates that the project is financially viable. The Internal Rate of Return (IRR) was de-

terminated by identifying the discount rate at which the NPV becomes zero, providing an internal benchmark for comparing with alternative investment opportunities. The Payback Period (PBP) was used to evaluate how long it takes for the project to recover its initial capital investment, measured by the point at which cumulative net cash flows become equal to or exceed the initial expenditure. Finally, the Benefit-Cost Ratio (B/C) was calculated as the ratio between the present value of benefits and the present value of costs. A B/C ratio greater than one suggests that the project's benefits outweigh its costs, thereby justifying implementation. Together, these financial indicators offered a comprehensive assessment of the project's profitability, investment risk, and potential for return. This economic analysis complemented the technical evaluation, supporting the overall feasibility of converting POME-derived biogas into hydrogen and electricity via PEM fuel cells while enhancing voltage stability in the distribution grid.

### 3. Results and Discussion

#### 3.1 Hydrogen production via dry methane reforming

The hydrogen production process via Dry Methane Reforming (DMR), as illustrated in Fig. 2, begins with compressing the inlet air in a compressor unit to increase its pressure before mixing with biogas derived from Palm Oil Mill Effluent (POME). The biogas, serving as the primary feedstock, is composed of approximately 60% methane ( $\text{CH}_4$ ), 35% carbon dioxide ( $\text{CO}_2$ ), and 5% nitrogen ( $\text{N}_2$ ) by volume. The mixture is preheated to  $35^\circ\text{C}$  and pressurized to 500 kPa prior to entering the reactor, with a total molar flow rate of 690 kgmole/h and a corresponding mass flow rate of 18,680 kg/h.

Before entering the reformer, the gas

mixture is homogenized in a mixer to ensure uniform composition and temperature distribution. Inside the Plug Flow Reactor (PFR), the reforming reaction proceeds under endothermic conditions at elevated temperatures in the presence of a nickel-based catalyst ( $\text{Ni}/\text{Al}_2\text{O}_3$ ). The molecular weights of the main components— $\text{CH}_4$ ,  $\text{CO}_2$ , and  $\text{N}_2$ —used for the simulation and material balance are summarized in Table 1 (adapted from Hosseini & Wahid, 2015). These values were applied to calculate molar-to-mass conversions in Aspen HYSYS and to establish accurate flow relationships among the feed, products, and intermediates within the DMR process.

**Table 1.** Molecular weight of principal components in POME biogas.

| Component                        | Chemical Formula | Molecular Weight ( $\text{g}\cdot\text{mol}^{-1}$ ) | Role in Biogas Composition                                                                                                                                                                                                                          |
|----------------------------------|------------------|-----------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Methane ( $\text{CH}_4$ )        | $\text{CH}_4$    | 16.04                                               | Main combustible component; primary reactant in Dry Methane Reforming (DMR). Co-reactant in DMR; reacts with $\text{CH}_4$ to form syngas ( $\text{CO} + \text{H}_2$ ). Inert gas, typically from air intrusion; non-reactive under DMR conditions. |
| Carbon Dioxide ( $\text{CO}_2$ ) | $\text{CO}_2$    | 44.01                                               |                                                                                                                                                                                                                                                     |
| Nitrogen ( $\text{N}_2$ )        | $\text{N}_2$     | 28.01                                               |                                                                                                                                                                                                                                                     |

This reaction produces hydrogen ( $\text{H}_2$ ) and carbon monoxide ( $\text{CO}$ ) as the main outputs. After leaving the reactor, the product gases are routed to a splitter where hydrogen is separated using membrane or adsorption-based techniques, then cooled and stored in a dedicated tank at  $59.85^\circ\text{C}$  and 100 kPa. The resulting hydrogen stream, with a flow rate of 538.2 kgmole/h (1085 kg/h), is used as fuel in a pro-

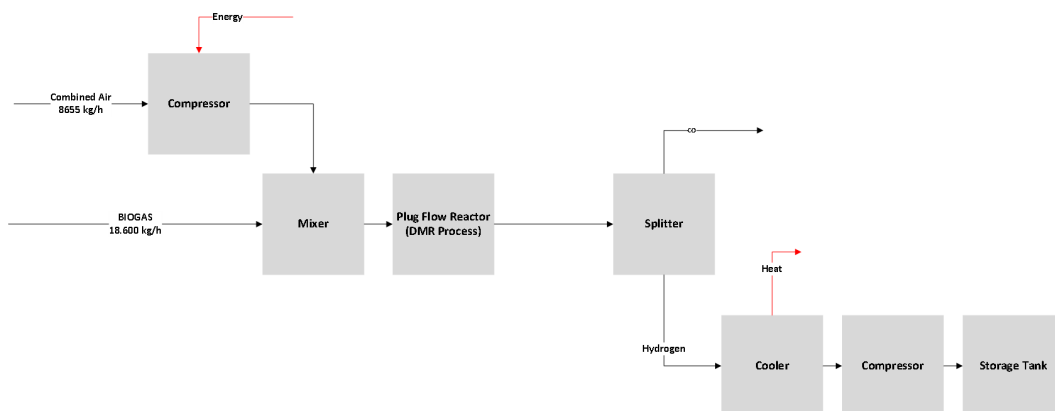


Fig. 2. Hydrogen production simulation.

ton exchange membrane fuel cell (PEMFC) system.

The simulation results given in Table 1, indicate a strong dependence of hydrogen yield on reactor temperature. At 200°C, hydrogen production is minimal (0.11 kgmole/h), but it increases sharply with temperature, reaching 538.2 kgmole/h at 500°C.

This trend aligns with the endothermic nature of the DMR reaction, whereby increasing temperature enhances the reaction rate as described by the Arrhenius equation. The simulation applied a kinetic model with an activation energy ( $E_a$ ) of 155.353 kJ/mol and a pre-exponential factor ( $A$ ) of  $2.13 \times 10^{13}$ , showing exponential growth of the reaction rate with temperature. The Ni/Al<sub>2</sub>O<sub>3</sub> catalyst used in this process operates under the Langmuir-Hinshelwood mechanism, in which CH<sub>4</sub> and CO<sub>2</sub> are adsorbed on the catalyst surface prior to the reaction [9].

A sharp increase in hydrogen production (refer to Fig. 3.) was observed between 300°C and 400°C, from 71.2 to 514.3 kgmole/h, suggesting a threshold temperature at which the reaction becomes significantly more efficient. Above 500°C, the increase

in hydrogen output begins to plateau, likely due to thermodynamic equilibrium limitations. Although industrial-scale DMR is typically conducted at 800–1000°C to maximize CH<sub>4</sub> and CO<sub>2</sub> conversion and to minimize carbon formation (coking), the simulation shows that 500°C is already sufficient to achieve near-optimal conversion.

However, long-term catalyst stability remains a concern at high operating temperatures due to potential sintering, which reduces the active surface area and, consequently, catalytic activity. The observed plateau in hydrogen yield above approximately 500°C can be explained by thermodynamic equilibrium limitations and the onset of competing side reactions such as the reverse water–gas shift and Boudouard (carbon formation) reactions. Although increasing temperature enhances reaction kinetics following Arrhenius behavior and thermodynamically favors the endothermic DMR process, the overall equilibrium constant and secondary reactions eventually restrict further increases in hydrogen molar fraction. As a result, the incremental gain in hydrogen production beyond 500°C becomes marginal under the modeled composition and flow conditions.

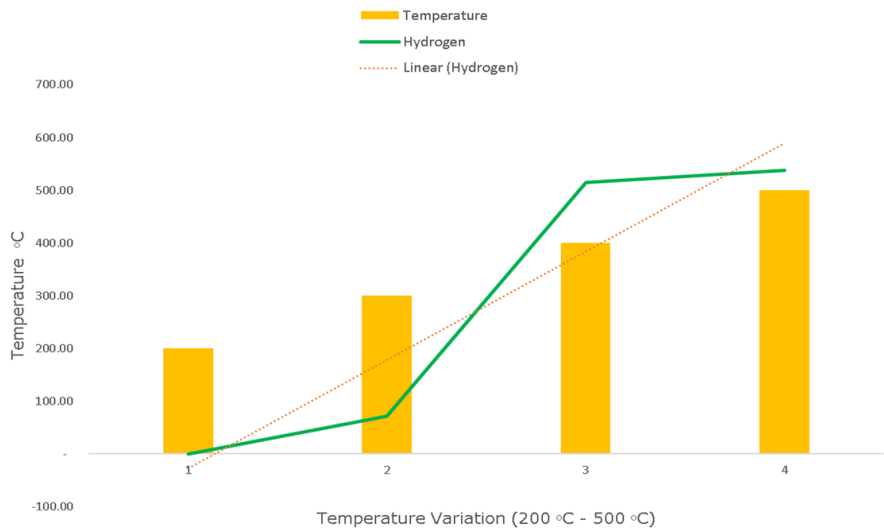


Fig. 3. Effect of DMR reactor temperature on hydrogen production.

Table 2. Hydrogen production simulation results (molar and mass flows).

| Parameter       | Unit     | Stream    |           |           |           |
|-----------------|----------|-----------|-----------|-----------|-----------|
|                 |          | 4         | 4         | 4         | 4         |
| Temperature     | °C       | 200.00    | 300.00    | 400.00    | 500.00    |
| Pressure        | kPa      | 200.00    | 200.00    | 200.00    | 200.00    |
| Molar Flow      | kgmole/h | 990.12    | 1,061.21  | 1,504.31  | 1,528.20  |
| Mass Flow       | kg/h     | 27,333.23 | 27,333.23 | 27,333.23 | 27,333.54 |
| Component Flow  |          | 4         | 4         | 4         | 4         |
| Oxygen          |          | 63.00     | 63.00     | 63.00     | 63.00     |
| Nitrogen        |          | 243.90    | 243.90    | 243.90    | 243.90    |
| Methane         | kgmole/h | 413.94    | 378.40    | 156.85    | 144.90    |
| Carbon Dioxide  |          | 269.04    | 233.50    | 11.95     | 0.00      |
| Hydrogen        |          | 0.11      | 71.21     | 514.30    | 538.20    |
| Carbon Monoxide |          | 0.11      | 71.21     | 514.30    | 538.20    |

Industrial DMR systems typically operate at 800–1000°C to maximize methane and carbon dioxide conversion while minimizing carbon deposition (coking), but such conditions demand higher energy input and impose severe thermal stress on catalysts and reactor materials. In contrast, the selected 500°C operating temperature in this simulation represents a practical compromise between conversion efficiency, process energy requirements, and catalyst stability. This temperature also aligns with several literature reports

of optimized lower-temperature DMR operations under modified catalysts and enhanced reactor configurations [3, 9, 16–18].

To improve thermal stability and resistance to carbon deposition, industrial DMR systems often employ catalyst promoters such as MgO or CeO<sub>2</sub> or adopt bimetallic formulations (e.g., Ni–Co, Ni–Ru) supported on high-porosity materials to suppress sintering and prolong catalyst life. The present simulation assumes a conservative performance decline, with cat-

alyst replacement scheduled periodically and reflected in the operating expenditure (OPEX) estimates. Overall, the simulation confirms that hydrogen production via DMR is strongly temperature-dependent, with a near 1:1  $H_2/CO$  product ratio consistent with the stoichiometry of the reforming reaction and in agreement with industrial data from commercial DMR developers such as Linde and Haldor-Topsoe. These findings support the technical applicability of the process for renewable hydrogen generation, particularly when integrated with PEM fuel cell systems for distributed energy applications.

### 3.2 Hydrogen storage tank design

In this system, hydrogen produced via Dry Methane Reforming (DMR) is utilized as the primary fuel for Proton Exchange Membrane Fuel Cells (PEMFCs) and must therefore be stored in a manner that ensures both operational efficiency and safety. The storage system is designed to accommodate the total daily hydrogen requirement under nominal operating conditions of 59.85°C and 100 kPa. Hydrogen density is first estimated using the ideal gas law where applicable, yielding approximately 3.625 kgmole/ $m^3$ . For mechanical design, however, real-gas behavior and compressibility factors are included according to relevant codes and standards (ASME BPVC Section VIII and API 620).

Based on a continuous hydrogen production rate of 538.2 kgmole/h, the daily hydrogen requirement equals 12,916.8 kgmole/day. Converting this to mass, and applying the molar mass of hydrogen (2.016 kg/kgmole) under consistent SI units, gives a total daily hydrogen mass of 26,045.6 kg. This corresponds to a base gas volume of approximately 3,564.5  $m^3$  under the specified temperature and pressure conditions.

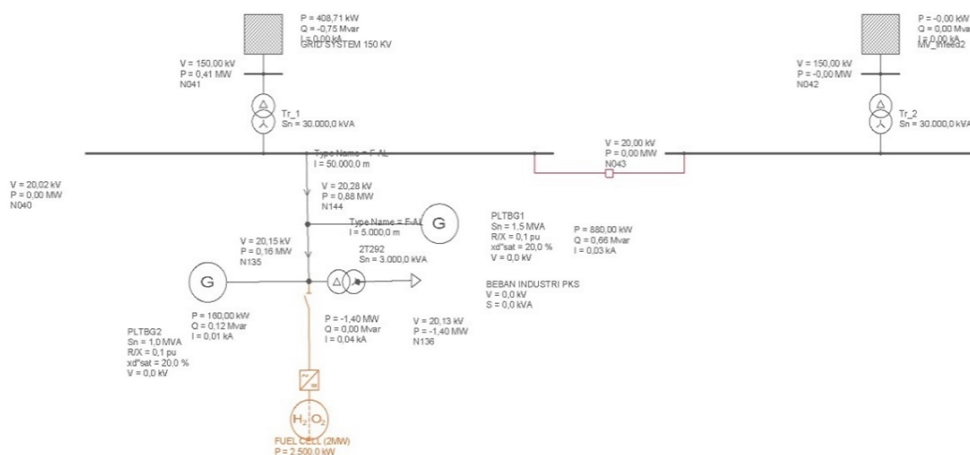
Incorporating a safety factor of 1.25 to account for process uncertainty and expansion allowance, the total design volume increases to 4,455.6  $m^3$ . The storage capacity is distributed across three identical spherical tanks, each having an effective volume of 1,485.2  $m^3$ . Using the volumetric relationship for a sphere, the resulting tank diameter is calculated to be 16.2 meters.

For pressure containment, the working pressure of 145.04 psi is increased by 10% to define a design pressure of 159.54 psi, consistent with ASME and API mechanical design requirements. The required wall thickness, calculated based on the allowable stress for carbon steel (12,650 psi) and corresponding safety factors, is 1.295 inches (0.0329 meters). All mechanical design calculations, including stress verification and structural integrity checks, are presented in the supplementary information (Section SI-D).

This design approach ensures that the hydrogen storage system satisfies both technical performance and safety standards while providing reliable supply continuity for the PEM fuel cell system. The corrections applied to unit conversions and design parameters have been verified numerically, ensuring full consistency across mass, molar, and volumetric balances. Consequently, the storage design achieves an optimal balance between safety, spatial efficiency, and cost-effectiveness, supporting stable long-term hydrogen-based power generation.

### 3.3 Power system design

The power system modeled in this study (refer to Fig. 4.) includes a transmission-to-distribution network ranging from 150 kV down to 20 kV. The main components consist of the national 150 kV transmission grid, two 30,000 kVA step-



**Fig. 4.** Power system configuration.

down transformers, a 20 kV distribution network, and an industrial load representing a palm oil processing facility. The 150 kV grid is stepped down to 20 kV through the transformers to match the voltage level required by the distribution network. Voltage across the 20 kV system ranges from 20.00 kV to 21.18 kV, with minor fluctuations due to power flow dynamics and line impedance characteristics.

The industrial load is included as a major consumer in the model, although in the initial simulation stage, it remains idle, with both real and apparent power recorded as 0 kW and 0 kVA, indicating no active power consumption. In addition to the main grid and load, a 2 MW hydrogen fuel cell system is integrated into the 20 kV network. This fuel cell acts as an alternative energy source designed to support power supply and enhance voltage stability, especially during grid disturbances or generation shortfalls.

Overall, the system configuration reflects a flexible power network integrating multiple energy sources, including the main grid, a local biogas power plant (PLTBG),

and a hydrogen-based fuel cell, providing resilience and support for renewable energy integration.

### 3.4 Power system simulation results

This study analyzes the integration of a hydrogen fuel cell into a 20 kV distribution network, aiming to improve voltage stability and supply reliability for industrial loads. Simulations were conducted to compare system performance before and after the fuel cell was introduced, considering load variation, generation capacity, and voltage fluctuation across the network.

In the initial configuration, as shown in Fig. 4, power was supplied solely by two biogas power plants (PLTBG 1 and 2), which served the palm oil processing facility. Simulation results revealed major voltage stability issues. As shown in Fig. 5, system voltage dropped significantly, with minimum values ranging from 12.51 kV to 17.79 kV—well below the operational standard of  $\pm 5\%$  around the nominal 20 kV [11]. This instability was caused by limited generation capacity, imbalance between load demand and available supply,

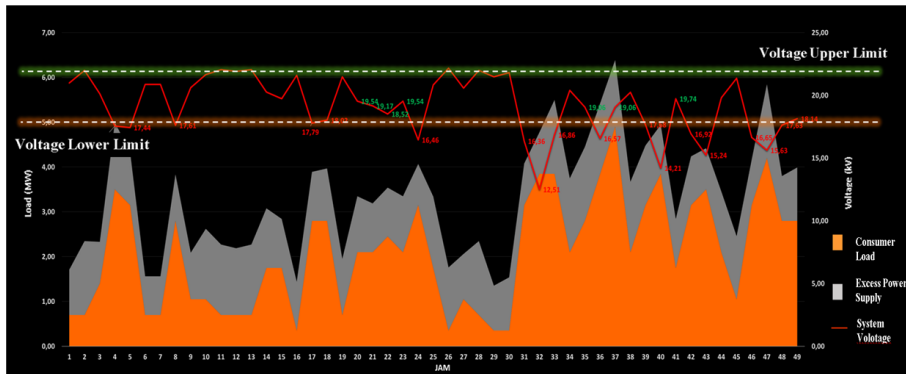


Fig. 5. Power system profile before fuel cell integration.

and high line reactance, which led to substantial voltage drops during power flow.

Such voltage deviations pose a risk to industrial operations, particularly for sensitive equipment such as electric motors and control systems. Furthermore, despite grid interconnection, the high impedance in the distribution network limited the effectiveness of external support, making the system vulnerable during load surges.

Following the integration of a 2 MW hydrogen fuel cell into the 20 kV network, simulation results showed marked improvements in voltage profile and power distribution. As illustrated in Fig. 6, voltage levels stabilized within the range of 19.5 kV to 22.16 kV, significantly reducing the previous fluctuations.

This improvement was attributed to the active power contribution from the fuel cell, which directly supported industrial load demand, reduced the current drawn from the main 150 kV grid, and minimized distribution losses.

Additionally, the fuel cell improved the system power factor by supplying primarily active power with minimal reactive power, thereby easing the reactive burden on the network. Power flow patterns also shifted, with reduced load on the biogas plants and the main grid. This led to a more

balanced system, reduced risk of overloading, and enhanced flexibility in responding to load variations, particularly during peak industrial demand.

### 3.5 System stability and reliability evaluation

The integration of hydrogen-based fuel cells into the 20 kV power distribution system significantly improved system stability and reliability. Before integration, voltage levels dropped to as low as 16.46–17.79 kV, which is below the acceptable operational standard of  $\pm 5\%$  around the nominal 20 kV. After fuel cell deployment, voltage stabilized within the range of 19.5–22.16 kV, indicating a substantial reduction in fluctuations and enhanced power quality for industrial loads. The additional power supply from the 2 MW fuel cell reduced the load imbalance previously experienced when the system relied solely on the biogas power plants (PLTBG) and the 150 kV main grid. This new configuration prevented power deficits and mitigated voltage collapse during high-demand periods.

The fuel cell also optimized power flow across the network by lowering the current drawn from the main grid, thereby reducing line losses and increasing overall efficiency. In addition, the fuel cell primar-

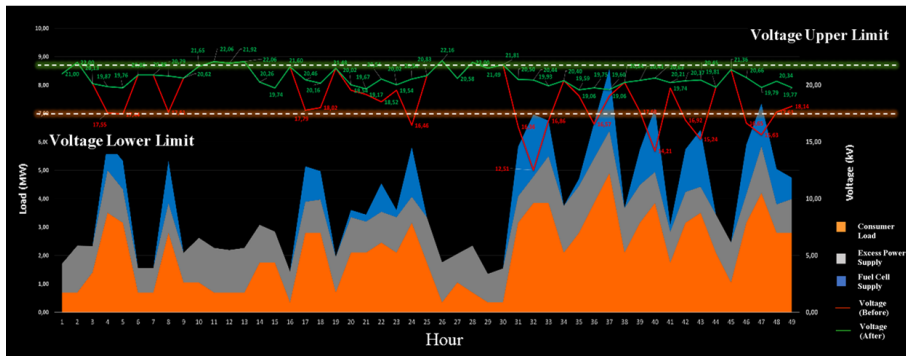


Fig. 6. Power system profile after fuel cell integration.

ily supplies active power without generating excess reactive power, which improved the system's power factor and reduced the need for reactive power compensation. This contributes to more efficient and stable grid operation.

To benchmark the performance of the PEM fuel cell system with hydrogen storage, a comparison was made with a Solid Oxide Fuel Cell combined with Compressed Air Energy Storage (SOFC + CAES) system, as discussed by [12]. While SOFC + CAES offers superior flexibility and fast load-following capabilities, especially in isolated or off-grid systems, PEMFC with hydrogen storage is more suitable for grid-connected applications. PEMFCs enhance peak load support and voltage regulation without the need for complex mechanical storage systems. Thus, although SOFC + CAES performs well in standalone configurations, PEMFC systems are highly effective for improving power quality in medium-voltage distribution networks like the 20 kV grid analyzed in this study.

While some literature highlights that PEMFC systems can also offer fast dynamic response and limited frequency regulation capability through their power electronic interfaces, such aspects were beyond

the scope of this study. The present analysis was specifically designed to evaluate steady-state voltage stability and the impact of PEMFC integration on voltage profile improvement in the 20 kV distribution grid.

Dynamic and frequency-domain analyses—such as transient stability, electromechanical oscillations, or frequency support under disturbance—require a detailed control model and time-domain simulations (e.g., EMT or PSCAD-type studies), which were not included in this research.

These advanced analyses are therefore recommended for future work, particularly to assess the PEMFC's contribution to short-term frequency support and ramp-rate performance under real-time grid conditions.

### 3.6 Economic performance and investment feasibility analysis

The simulation results indicate that power demand not fully met by the bio-gas power plants (PLTBG 1 and 2) must be supplemented using diesel generators. This unmet demand was quantified to calculate the corresponding industrial biodiesel (HSD) consumption costs. Simultaneously, hydrogen production from the DMR process remained constant at 1,085 kg/h, while

actual fuel cell demand was significantly lower, resulting in a substantial surplus of hydrogen. This surplus, detailed in Table 18, presents an opportunity for commercialization, either in the industrial sector or hydrogen-based transportation.

Based on assumed fuel and hydrogen prices—IDR 22,600/L for biodiesel [13] and IDR 65,400/kg for hydrogen [14]—annual diesel fuel costs were estimated at IDR 120.4 billion. In contrast, annual revenue from hydrogen sales could reach IDR 290.8 billion. This yields a hydrogen-to-diesel cost ratio of 2.42, indicating strong economic viability and profitability from hydrogen production, even after accounting for diesel backup requirements.

The economic viability of constructing a hydrogen production facility utilizing Dry Methane Reforming (DMR) and fuel cell integration was assessed through a detailed capital investment model. This financial study is based on several key assumptions, including a two-year construction period commencing in early 2027 and culminating in full-scale operation by 2029. The plant is expected to operate for 30 years, with a production schedule of 330 days per year to accommodate preventive maintenance and turnaround activities. All financial metrics are evaluated in both Indonesian Rupiahs (IDR) and United States Dollars (USD), with an exchange rate fixed at USD 1 = IDR 16,898 based on May 1, 2025 data.

Capital expenditure (CAPEX) estimations were carried out using the Guthrie Modular Method, a widely recognized approach for estimating process plant investments during the early design stage. This method categorizes expenditures into direct and indirect cost components, including equipment purchases, land acquisition, civil construction, offsite facilities, start-up

costs, and licensing fees. The total capital investment (TCI) incorporates both Total Permanent Investment (TPI) and Working Capital (WC), enabling a comprehensive view of upfront funding needs. A simplified CAPEX equation from Seider et al. [15] was used to streamline calculations and align with standardized cost engineering principles.

To account for inflationary effects on equipment costs, the Chemical Engineering Plant Cost Index (CEPCI) was applied. The index values from 2000 through 2022 were sourced from The University of Manchester and extrapolated through 2027 using trend-line regression. This approach ensures that the estimated equipment costs reflect anticipated market conditions at the time of procurement and minimizes the risk of underbudgeting. Integrating this index within the Guthrie-based CAPEX framework enhances the reliability and relevance of the financial projections provided in this study.

The economic feasibility of the proposed Dry Methane Reforming (DMR) and fuel cell plant is evaluated using a comprehensive set of profitability indicators. These include Cash Flow, Internal Rate of Return (IRR), Net Present Value (NPV), Payback Period (PBP), Break-Even Point (BEP), and the Benefit-Cost Ratio (B/C Ratio). These financial metrics were selected to provide a holistic assessment of the project's ability to generate returns over time, recover capital investment, and justify economic efficiency under time-value-of-money considerations.

Cash Flow analysis reflects the pattern of inflows and outflows throughout the project's lifetime. IRR represents the maximum rate of return expected from the project, while NPV quantifies the net value of future cash flows discounted to present value. PBP measures the period re-

quired to recover the initial capital, and BEP identifies the minimum production volume at which revenues equal total operational costs. The Benefit-Cost Ratio further serves as a decision-making criterion by comparing total expected benefits to total costs, indicating the economic efficiency of the investment.

In addition to profitability analysis, a sensitivity analysis is conducted to assess the project's resilience against variations in key economic variables. Three core parameters—IRR, NPV, and PBP—are tested for their sensitivity to changes in hydrogen selling price, capital expenditures (CAPEX), and operating expenditures (OPEX). This analysis helps identify critical thresholds and potential financial risks associated with market and cost uncertainties. The insights derived from this evaluation provide strategic input for risk mitigation planning and enhance the robustness of investment decision-making.

**Table 3.** Results of investment feasibility analysis.

|                           |                   |
|---------------------------|-------------------|
| <b>Investment (Mn Rp)</b> | \$17,178,364      |
| <b>BEP</b>                | 14,575 ton        |
| <b>NPV</b>                | USD 44,914,690.08 |
| <b>IRR</b>                | 12.78 %           |
| <b>Pay Back Period</b>    | 3,21 years        |
| <b>B/C Ratio</b>          | 2,61              |

Based on the financial analysis in Table 2, the hydrogen production project demonstrates strong investment feasibility, with a total capital expenditure of approximately IDR 17.18 billion (USD-equivalent). The project yields a Net Present Value (NPV) of USD 49.58 million, an Internal Rate of Return (IRR) of 53.61%, and a Payback Period of only 2.7 years. A Benefit-to-Cost (B/C) Ratio of 2.8 and a Break-Even Point (BEP) at 12,278.16 tons of hydrogen further confirm

the project's economic attractiveness and profitability under the given technical and financial assumptions.

In conclusion, the economic analysis confirms that hydrogen production and utilization via PEM fuel cells is not only technically viable but also economically advantageous. The system delivers significant profitability through hydrogen sales, rapid capital recovery, and reduced dependence on fossil fuels. These outcomes position the project as a compelling solution for supporting industrial decarbonization and enhancing the flexibility and resilience of future power systems powered by renewables.

A sensitivity analysis was conducted to evaluate the impact of key economic variables—including hydrogen (H<sub>2</sub>) selling price, capital expenditure (CAPEX), raw material cost, and utility cost—on the project's financial metrics: Internal Rate of Return (IRR), Net Present Value (NPV), and Payback Period (PBP). The results provide insights into the project's robustness against market fluctuations and investment risks.

The IRR sensitivity plot shows that H<sub>2</sub> price has the most significant positive impact on project profitability. A 20% increase in H<sub>2</sub> price raises the IRR from 53.6% to nearly 67%, while a 20% decrease drops it to below 43%. In contrast, CAPEX exhibits a strong inverse relationship with IRR, where a 20% increase in capital cost reduces IRR to approximately 45%. Utility and raw material costs show relatively flat trends, indicating marginal influence on IRR within the evaluated range.

For Payback Period (PBP), similar patterns are observed. An increase in H<sub>2</sub> price shortens the PBP from 2.8 years to around 2.2 years, highlighting revenue sensitivity.

Conversely, rising CAPEX extends

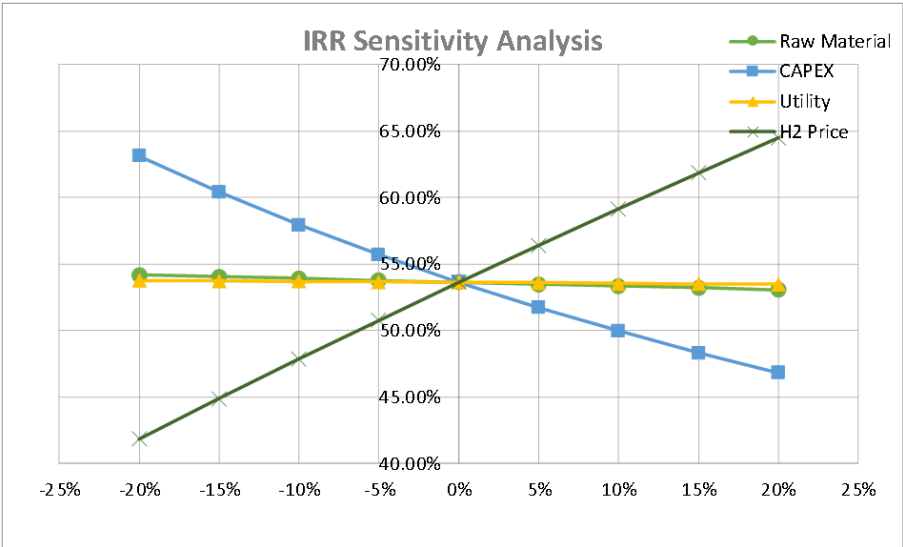


Fig. 7. IRR sensitivity analysis.

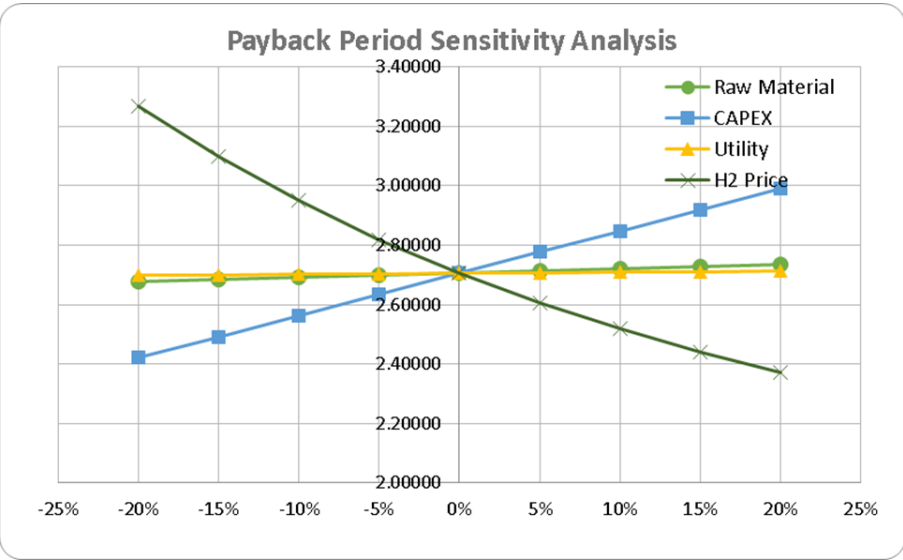


Fig. 8. Payback period sensitivity analysis.

the payback duration to over 3.2 years. Variations in utility and raw material costs slightly affect PBP, staying within a narrow band between 2.6 and 2.8 years, thus indicating operational cost resilience. In terms of Net Present Value (NPV), the project is highly responsive to changes in hydrogen price. A 20% increase in H<sub>2</sub>price boosts

NPV from USD 49.6 million to approximately USD 66 million. Meanwhile, a 20% increase in CAPEX reduces NPV to below USD 45 million. Once again, utility and raw material cost changes have minimal effects, with NPV remaining relatively stable across the evaluated sensitivity ranges. The sensitivity analysis confirms that

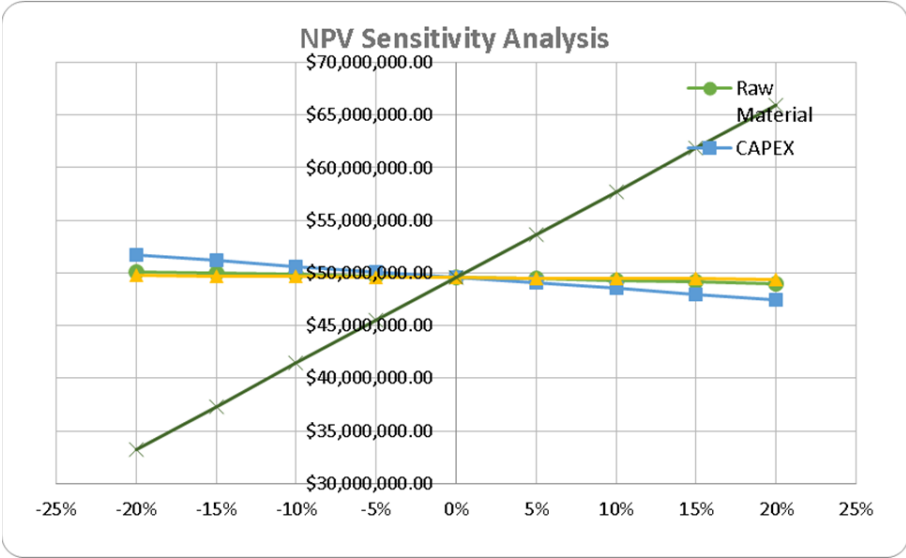


Fig. 9. NPV sensitivity analysis.

Table 4. Summary of sensitivity analysis on key economic parameters.

| Variable                    | Range Evaluated                   | Effect on IRR | Effect on NPV | Discussion                                                                                                                                 |
|-----------------------------|-----------------------------------|---------------|---------------|--------------------------------------------------------------------------------------------------------------------------------------------|
| H <sub>2</sub> Price        | ±20% from base value (USD 3.5/kg) | significant   | strong        | Most sensitive variable; directly influences revenue stream.                                                                               |
| CAPEX                       | ±20% from base investment         | moderate      | moderate      | High capital sensitivity; emphasizes cost control importance.                                                                              |
| OPEX                        | ±20% from base operation cost     | slight        | slight        | Operational costs have minor impact within evaluated range.                                                                                |
| Carbon Credit (qualitative) | Not included quantitatively       | N/A           | N/A           | Potential to improve NPV/IRR via monetized CO <sub>2</sub> avoidance, but excluded due to lack of formal policy baseline in Indonesia [1]. |

hydrogen price and capital investment are the two most influential variables affecting project viability. This finding underscores the importance of accurate market forecasting and cost control strategies in ensuring the long-term financial sustainability of the hydrogen production facility. In response to the reviewer’s suggestion, Table 5 presents a consolidated sensitivity analysis focusing on three key economic parameters—hydrogen (H<sub>2</sub>) selling price, capital expenditure (CAPEX), and operating expenditure (OPEX)—as these represent measurable and verifiable factors that directly influence the techno-economic performance

of the system.

The carbon credit variable was not included in this study because Indonesia’s current carbon pricing regulations remain limited in scope, primarily applying to the electricity sector, and are still under development to expand into other industrial sub-sectors. Therefore, the absence of a defined carbon pricing mechanism for POME-based hydrogen projects reflects the existing regulatory framework rather than a limitation of the study. Nonetheless, the potential economic benefit from future carbon credit implementation is acknowledged qualitatively, as such mechanisms could

further enhance project profitability once comprehensive and sector-inclusive policies are established.

Although the economic assessment indicates strong commercialization potential, several critical challenges must be addressed to ensure long-term investment sustainability. The most prominent concern involves maintaining a consistent and reliable feedstock supply to sustain stable hydrogen production. Variability in biogas generation and limited transparency of feedstock data from palm oil mills pose potential risks to continuous operation. Furthermore, the hydrogen market price, identified as the most sensitive factor, directly affects revenue projections, investment returns, and overall project resilience. Therefore, implementing feedstock assurance strategies—such as long-term contracts with mill operators—and adopting price stabilization mechanisms for hydrogen sales are essential components of effective risk management and investment planning for this renewable hydrogen production system.

A scenario-based analysis, as presented in Table 3, reveals that the profitability of the hydrogen production plant is highly sensitive to fluctuations in hydrogen ( $H_2$ ) market prices. Under the first scenario, where  $H_2$  prices decline periodically from USD 3.5 to USD 1.5, the project yields a strong Internal Rate of Return (IRR) of 36.69%, a positive Net Present Value (NPV) of USD 25,387,740.48, and a relatively short Payback Period (PBP) of 3.67 years—indicating high investment attractiveness. In the second scenario, with a flat price reduction to USD 2.99, the financial indicators remain favorable, with an IRR of 32.69%, a positive NPV, and a slightly extended PBP of 4.46 years. However, the Break-Even Point (BEP) increases, reflecting the need for higher production volumes

to offset investment costs.

Conversely, in the third scenario, where  $H_2$  prices decline flatly to USD 1.5, the project becomes financially unviable. The IRR drops significantly to 9.69%, the NPV turns negative at USD -3,037,308.67, and the PBP extends to 11.03 years—highlighting substantial risks under low-price conditions. These results underscore the critical influence of hydrogen pricing on overall project feasibility. A significant decline in  $H_2$  selling prices may severely erode profitability and hinder investment recovery.

Therefore, further evaluation of future  $H_2$  price trends is essential to ensure long-term project viability. Strategic measures such as securing stable feedstock supply, promoting data transparency among biogas-producing industries, and conducting in-depth market analysis on hydrogen pricing dynamics are imperative. These actions are expected to strengthen the economic resilience of the project and support its successful deployment in the face of market volatility.

#### 4. Conclusion

This study demonstrates that hydrogen production from POME-derived biogas through Dry Methane Reforming (DMR), integrated with a Proton Exchange Membrane Fuel Cell (PEMFC), is both technically and economically feasible for enhancing power quality in a 20 kV distribution grid. The simulation using Aspen HYSYS confirmed optimal hydrogen production of 1,085 kg/h, which is sufficient to supply a 2.115 MW PEMFC system operating at 33.76% electrical efficiency. The PEM fuel cell effectively stabilized voltage fluctuations, improving voltage levels from 12.51–19.67 kV to 19.5–22.16 kV, and reduced system reliance on the 150 kV transmission

**Table 5.** Impact of hydrogen price scenarios on project financial performance metrics.

| Scenario                                             | H <sub>2</sub> Price (USD/kg) | IRR (%) | NPV (USD)     | Payback Period (Years) | Break-Even Point (tons H <sub>2</sub> ) |
|------------------------------------------------------|-------------------------------|---------|---------------|------------------------|-----------------------------------------|
| Periodic Decline in H <sub>2</sub> Price (3.5 → 1.5) | 1.5                           | 36.69   | 25,387,740.48 | 3.67                   | 16,216.83                               |
| Flat Decline in H <sub>2</sub> Price (3.5 → 2.99)    | 2.99                          | 32.69   | 25,787,871.45 | 4.46                   | 19,649.20                               |
| Flat Decline in H <sub>2</sub> Price (3.5 → 1.5)     | 1.5                           | 9.69    | -3,037,308.67 | 11.03                  | 48,668.28                               |

grid. A spherical hydrogen storage system was designed to ensure safety, operational efficiency, and pressure containment. Economically, the project demonstrates strong profitability. With annual hydrogen revenue estimated at USD 19.05 million, far exceeding backup diesel costs of USD 7.88 million, the system achieves a revenue-to-cost ratio of 2.42. Financial analysis confirms high investment attractiveness, with a Net Present Value (NPV) of USD 49.58 million, an Internal Rate of Return (IRR) of 53.61%, a Payback Period of just 2.7 years, and a Benefit-Cost Ratio (B/C) of 2.8—well above conventional economic thresholds for project feasibility. Sensitivity analysis highlights that hydrogen selling price is the most critical variable influencing financial viability. Under a periodic decline in H<sub>2</sub> price from USD 3.5 to 1.5 per kg, the project maintains its attractiveness with an IRR of 36.69% and a positive NPV of USD 25.39 million. A moderate flat price drop to USD 2.99/kg yields slightly reduced performance (IRR: 32.69%, NPV: USD 25.79 million), still within acceptable margins. However, under an extreme flat drop scenario to USD 1.5/kg, the IRR falls sharply to 9.69%, the NPV turns negative at -USD 3.04 million, and the Payback Period extends to 11.03 years—rendering the project financially unviable. In summary, the integration of DMR and PEMFC offers a technically robust and financially rewarding pathway for improving power

quality and reliability in medium-voltage grids. However, its long-term success depends on stabilizing feedstock supply, ensuring transparent biogas availability data, and implementing risk mitigation strategies to manage market uncertainty, particularly related to hydrogen pricing.

### Acknowledgements

This research and its implementation are supported by Indonesia University through the Master Program and State Electricity Company.

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