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# Integrated Hydrogen and Energy Planning: Case Study for Sarawak

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Sarawak is emerging as a key player in Southeast Asia's low-carbon energy transition, with growing ambitions to expand electricity and hydrogen supply for domestic, industrial growth, and cross-border hydrogen and energy exports. However, Sarawak needs to address challenges, including the need to balance cost-effectiveness, emissions reduction, and infrastructure readiness while navigating uncertain policy and market dynamics. In response, this research developed a linear programming (LP) optimisation model to identify the solutions to these gaps. The proposed model focuses on demand-side cost optimisation within an electricity–hydrogen integrated energy system (EH-IES) encompassing industrial, transport, residential, and commercial end uses. The findings show that the carbon-tax level that most effectively motivates local industrial decarbonisation is 592 MYR/t $CO_2$-eq, with no binding carbon cap and hydrogen prices stable at approximately 52.875 × $10^6$ MYR/PJ and 35.250 × $10^6$ MYR/PJ (equivalent to 6.35 MYR/kg $H_2$ and 4.23 MYR/kg $H_2$ for blue and grey hydrogen). This value of carbon tax signifies the great resistance to decarbonising local demand sectors, and the requirement of additional support policies to implement the carbon tax at a gentle pace.

## 1. Introduction

Sarawak is blessed with abundant resources, including hydropower, biomass, coal, and natural gas. This provides a variety of choices for Sarawak's energy system. The current Sarawak energy system consists of electricity produced from hydropower plant, which makes up 75% of the total electricity produced (Lee et al., 2023). Building on this foundation, deeper decarbonisation actions in local energy systems have been explored, and one of the attempts that has been made by the Sarawak government is the integration of hydrogen. The state government seeks hydrogen, mainly blue and green hydrogen, as a plausible and feasible solution to reduce emissions when it is being used as feedstock in industries or fuel for combustion purposes (MEESty, 2025). The government's effort in promoting hydrogen energy was concluded in the Sarawak Hydrogen Energy Roadmap (SHER) in 2025. The roadmap has shown the future hydrogen demand and possible enablers to push the integration of hydrogen in local energy markets. However, as of 2025, Malaysia has not yet implemented a carbon pricing mechanism such as a carbon tax or carbon cap-and-trade. This creates a hindrance to the hydrogen system, as the transition of a system often requires exterior pressure or support at the early adoption stage. Added to the problem is that the impact of the policies on the local energy system remains uncertain. Under the rapid transitioning of the energy system and development of the hydrogen economy in Sarawak, the integration of the electricity system planning into hydrogen development strategies has become increasingly important. This integration is critical because hydrogen production, particularly through electrolysis, is highly dependent on the availability, cost, and reliability of electricity supply. Pan et al. (2020) have created an optimal electricity-hydrogen integrated energy system (EH-IES) planning model to address the generation-load uncertainty in the system under an ultra-high renewable penetration scenario. The literature identified that power

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to hydrogen and heat (P2HH) and seasonal hydrogen storage (SHS) can reduce the total annual cost of the system while reducing the capacities of renewable power plants required. Similar research can be seen from Fadhil et al. (2024), who developed an optimisation model of a hydrogen supply chain (HSC) that explicitly couples green-electricity generation with hydrogen production, storage, transport, and end-use across industrial zones. These literatures highlighted the importance of incorporating advanced electricity system planning into hydrogen energy planning but lacks insight into the effect of system optimisation on detailed demand sectors. Thus, this research expands on this point of view by adopting a policy scenario analysis of the EH-IES system planning to identify the impact of the optimisation of the EH-IES system, including the demand sectors, on the energy landscape of the demand sectors.

To address these gaps, a linear-programming (LP) optimisation model for Sarawak (2025–2030) is developed to minimise total cost while endogenously determining total annual emission, electricity, and hydrogen demand, subject to utility demand, technology availability, fuel supply, and emissions constraints. The model disaggregates industrial sectors into nine sub-sectors and, together with transport, residential, and commercial sector maps, utility to technologies and carriers; and distinguishes hydrogen classes alongside conventional fuels, consistent with contemporary hydrogen-integration frameworks for industry. The model also considered a like-for-like comparison between carbon tax and annual carbon cap policies. The numerical data input and output of the model, as well as the formulation of the equation, are done via Excel-GAMS integration.

## 2. Problem Statement

Let *s* denote sectors, *ut* denote utility, *te* denote technologies, *c* denote carrier, *f* denote feedstocks, and *t* denotes time in years. Each sector required one or a few utilities demand, which is produced through any allowable technologies each year $(x_{s,ut,te,t})$. In details, there are four nodes in utilities (heating, electrify, fueling and non-energy), which are the utilities demand required by eleven sectors (iron and steel industry, cement industry, alumina industry, glass industry, semiconductors industry, ammonia production industry, methanol industry, synthetic methane industry, other industry, transport sector, commercial sector and residential sector). These sectors can select any allowed technologies to fulfil the utilities demand they need. Each carrier is linked to a type of carrier (fuel, hydrogen ($H_2$), and electricity) that the technology can use to operate the process, and each carrier is linked back to the respective classes of feedstocks (coal, diesel, natural gas, biodiesel, Liquefied Petroleum Gas (LPG), green hydrogen, blue hydrogen, and grey hydrogen). Thus, when sectors fulfil their utilities demand, cost, and emissions will be generated throughout the process. This research aims to minimise the total cost (Z) of the system, subject to constraints like utility balances and emissions balances. The details nodes considered within each layer, respectively, pairing between each of the nodes can refer to Figure 1 or Table A4 in the supplementary materials (Lim et al., 2025).

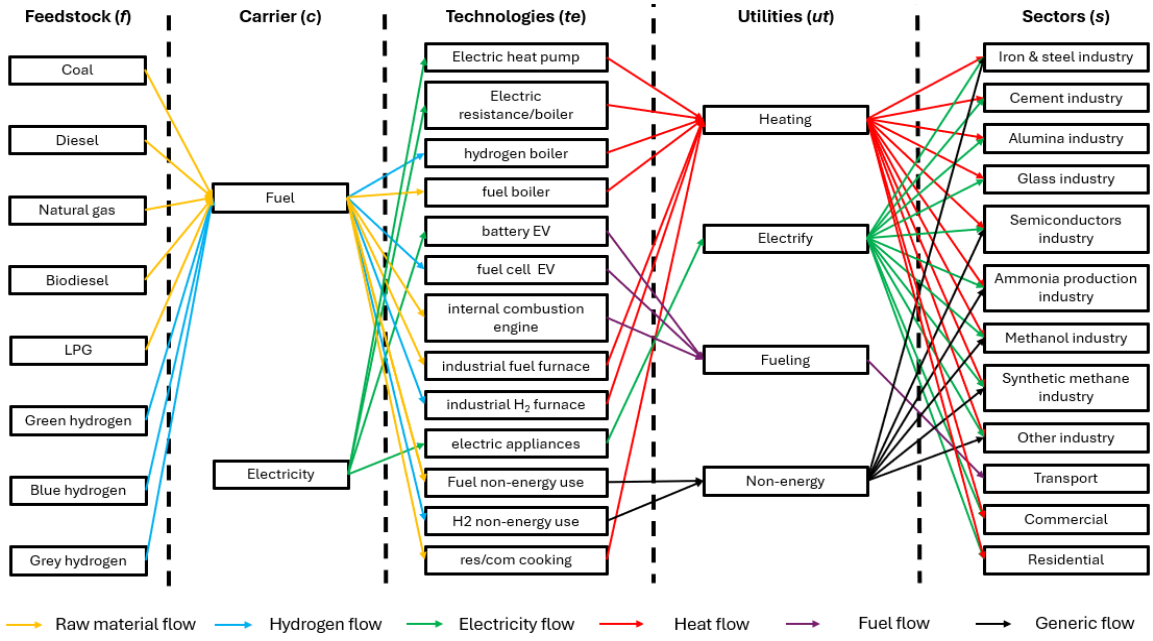


*Figure 1: Overall system superstructure*

## 3. Methodology

This section presents the key assumptions and the proposed LP model of this work.

### 3.1 Key Assumptions

The following are the assumptions that have been made regarding this research:

1) The hydrogen production capacity for all types of hydrogen is assumed to be unlimited.
2) The efficiency of all technologies is assumed to remain constant throughout the analysis.
3) The carbon tax is applied only to the industrial sector, while the transport, commercial, and residential sectors are excluded from carbon taxation.
4) All electricity is assumed to be imported from sources located outside the defined system boundary of this study. Self-generated electricity within the demand sectors using feedstocks is not considered.
5) Factors such as vehicle reliability, infrastructure readiness, and vehicle cost are not considered in the transport sector model.

### 3.2 Formulation of LP Model

The objective function of the model is to minimise the total cost $Z$. The total cost is the summation of the annual electricity cost, annual fuel cost, and carbon tax cost, which is shown in Eq(1). The annual electricity cost is the product of annual electricity demand ($P_{s,t}^{elec}$) and the electricity tariff ($\pi_{s,t}^{elec}$). The annual fuel cost is the product of the effective per-unit fuel price ($p_{f,t}^{fueleff}$), and the annual fuel demand ($Q_{f,t}^{fuel}$). The carbon tax cost term is the product of the carbon tax per unit of carbon emissions ($\tau_t$) and the emissions that are taxed with the cost ($E_t^{ct}$), which in this research is the nine sub-sectors of the industry sector and the transport sector.

$$\min Z = \sum_{s,t} \pi_{s,t}^{elec} P_{s,t}^{elec} + \sum_{f,t} p_{f,t}^{fueleff} Q_{f,t}^{fuel} + \sum_t \tau_t E_t^{ct} \quad (1)$$

Eq(2) is the utility balance, where the summation over ***te*** of the utility delivered by technology ($x_{s,ut,te,t}$) must equal the annual demand of the utility for each sector ($D_{s,ut,t}$). The respective calculations and reference for the utility demand are shown in Section C of the supplementary material (Lim et al., 2025). Eq(3) and Eq(4) are the annual electricity balance and fuel efficiency balance, where the annual electricity demand ($P_{s,t}^{elec}$) and fossil fuel flow to each technology, to each utility and sector each year ($q_{s,ut,\mathrm{te,f},t}^{fuel}$) are calculated using the efficiency of respective technologies ($\eta_{ut,te}$). Eq(5) is the calculation of annual fuel demand, where the total annual fuel demand ($Q_{f,t}^{fuel}$) is calculated from the summation of $q_{s,ut,\mathrm{te,f},t}^{fuel}$ for all sectors, all utilities and all technologies so that all the technologies, for all utilities in each sector included in the model. Eq(5) must meet the inequality constraint in Eq(6) so that supply ($S_{f,t}^{max}$) is always more than the demand. The sets ***ete*** and ***fte*** are the subsets of the overall technology set (***te),*** where ***ete*** consists of electricity-consuming technologies and ***fte*** fossil fuel-consuming technologies, respectively. Further details of the model formulation, including emissions constraints, are documented in the supplementary materials (Lim et al., 2025).

$$\sum_{te} x_{s,ut,te,t} = D_{s,ut,t} \qquad \forall s, ut, t \quad (2)$$

$$P_{s,t}^{elec} = \sum_{ut,ete} \frac{x_{s,ut,ete,t}}{\eta_{ut,ete}} \qquad \forall \mathrm{s}, t \quad (3)$$

$$\sum_f q_{s,ut,te,f,t}^{fuel} = \frac{x_{s,ut,fte,t}}{\eta_{ut,fte}} \qquad \forall s, ut, fte, t \quad (4)$$

$$Q_{f,t}^{fuel} = \sum_{s,ut,te} q_{s,ut,te,f,t}^{fuel} \qquad \forall f, t \quad (5)$$

$$Q_{f,t}^{f} \leq S_{f,t}^{max} \qquad \forall f, t \quad (6)$$

## 4. Case Study

The case study deals with EH-IES with the exogenous data of utility demand of each sector in Sarawak over the period of 2025-2030. The acquisition of the exogenous data and the calculation of the data of this research are summarised in the supplementary material (Lim et al., 2025). An optimisation is run for each scenario, and the observed variables (total annual cost, total annual emission, annual electricity demand, and annual hydrogen demand) are recorded. At the same time, the energy landscape in the demand sectors is obtained by observing the feedstocks and technologies used by each utility of each sector after each run.

## 5. Results and Discussion

The LP model is solved using the General Algebraic Modelling System (GAMS) distribution 46.0, and the numerical data input and output are done through Excel. In the GAMS model, there are 1,237 constraints, 24,883 variables, and a solving time of 0.03 seconds. This section summarises and explains the results obtained from the optimisation model under different scenarios considered. Besides, a sensitivity analysis is done to examine the robustness of the model created.

### 5.1 Scenario Analysis

This study uses scenario analysis (2025–2030) to assess total cost, emissions, electricity, and hydrogen demand, and the time required for sectoral decarbonisation. Two main mechanisms are considered: a carbon tax applied to Scope 1, Scope 2, and, depending on the scenario, hydrogen's upstream Scope 3 emissions; and a carbon tax combined with an $H_2$ fee-rebate that gives a fixed rebate per unit of $H_2$ plus an extra fee or rebate linked to $H_2$ emission intensity. A carbon cap is induced as a scenario, where it imposes an absolute upper limit on total emissions of the system, which cannot be exceeded by any means. The baseline scenario represents a reference case without any policy mechanism being applied. Scenario 1 applied a carbon tax to the system. Scenario 1a adds upstream GHG emissions (Scope 3) of hydrogen to the Scenario 1 context. Scenario 1b used the carbon tax with $H_2$ fee-rebate mechanism, which aims to evaluate its effect on the $H_2$ mixes across the demand sectors and the sectoral decarbonisation, while Scenario 2 applies the carbon cap scenario. For Scenarios 1, 1a, and 1b, a trial-and-error approach is used to determine the minimum carbon tax that triggers a shift from higher-emission technologies to cleaner alternatives in the demand sector. For Scenario 2, the same trial-and-error approach is applied to identify the lowest carbon cap that induces this technology switch while keeping the system feasible. Table 1 summarises the exact value settings of each scenario, while detailed descriptions are provided in the supplementary materials (Lim et al., 2025).

*Table 1: Comparison of Scenarios*

| Scenario | Carbon tax (MYR/t $CO_2$ eq) | Carbon cap (Mt $CO_2$ eq) | $H_2$ emission intensity (t $CO_2$ eq/PJ) | | | Hydrogen Fee-Rebate Mechanism | |
|---|---|---|---|---|---|---|---|
| | | | Grey $H_2$ | Blue $H_2$ | Green $H_2$ | Base cost reduction per unit $H_2$ (× $10^6$ MYR/PJ) | Additional fee or rebate per unit emission intensity of $H_2$ (MYR/ (t $CO_2$ eq/PJ)) |
| Baseline | - | - | - | - | - | - | - |
| Scenario 1 | Variable | - | - | - | - | - | - |
| Scenario 1a | Variable | - | 91,666 | 57,250 | 0 | - | - |
| Scenario 1b | Variable | - | 91,666 | 57,250 | 0 | 39.6 | 200 |
| Scenario 2 | - | Variable | - | - | - | - | - |

In the baseline scenario, the total annual cost and total annual emissions are 11,54 x $10^6$ MYR/y and 12.56 Mt $CO_2$ eq in 2030, respectively. The electricity demand grows moderately to 121.26 PJ/y by 2030, while hydrogen demand decreases slightly throughout the period, reaching 33.79 PJ/y in 2030. This indicates limited fuel and technologies switching without a system pressure on carbon.

In Scenario 1, where the carbon tax is introduced at $\tau_t$ = 592 MYR/t $CO_2$ with a non-binding carbon cap, reduces 2030 emissions to 7.59 Mt $CO_2$, a 39.6 % cut relative to the baseline scenario. This abatement is achieved alongside an electricity demand of 124.57 PJ/y and a hydrogen demand of 126.40 PJ/y in the year 2030. However, the total annual cost for this emissions reduction is also significant, with a 56.8 % increment from baseline, reaching 18,095 x $10^6$ MYR/y in 2030. Besides, the carbon tax obtained in this scenario is higher than that of other countries, like Singapore's carbon tax of 25 SGD/t $CO_2$, equivalent to 81.59 MYR/ t $CO_2$. This is mainly because fossil fuels such as natural gas are more affordable in Malaysia compared to hydrogen, creating a strong resistance against the decarbonisation action. Economic aid from the government, like hydrogen fuel subsidies, can be explored as support policies to reduce the decarbonisation hindrance.

Scenario 2 tightens the cap to the minimum, which is 7.41 Mt $CO_2$. The emission in 2030 for this scenario is lower than the baseline by 41.0 %. The cost burden is much lighter: total cost $Z$ is 24.58 % above baseline but 20.76 % lower than Scenario 1, with total annual cost at 2030 being 14.49 x $10^6$ MYR/y. Energy-vector adjustments remain hydrogen-led, with 136.83 PJ/y $H_2$ in 2030, while 2030 electricity demand is 121.26 PJ/y.

The total annual cost of Scenario 1a and Scenario 1b are 38,147 x $10^6$ MYR/y and 28,498 x $10^6$ MYR/y, respectively, in 2030, which are both higher than that in Scenario 1. Besides, the total annual emission of Scenario 1a and Scenario 1b is both 10.25 Mt $CO_2$ eq in 2030. However, the carbon tax to push for full

decarbonisation for Scenario 1a and 1b is 2407 MYR/t $CO_2$ eq and 1590 MYR/t $CO_2$ eq. These values indicate that there is a significant resistance to decarbonisation in these two scenarios. This is because now the only cleaner route of choosing hydrogen as fuel received an emission cost penalty and the hydrogen fee-rebate mechanism in Scenario 1b did not ease the problem because the rebatement considered did not decrease the cost per unit of green and blue hydrogen enough to make them cheaper than original grey hydrogen price, but grey hydrogen is further charged with extra fee, making the whole hydrogen technologies choice not much cheaper than fossil fuel technologies. Thus, the sectors prefer cheaper fossil fuels and pay the coupled carbon tax. The comparison of total annual cost $(Z_t)$, total annual emissions $(E_t)$, annual electricity demand $(P_t^{elec})$ and annual hydrogen demand $(H_t)$.between scenario are shown in Figure 2a, Figure 2b, Figure 2c, and Figure 2d respectively.

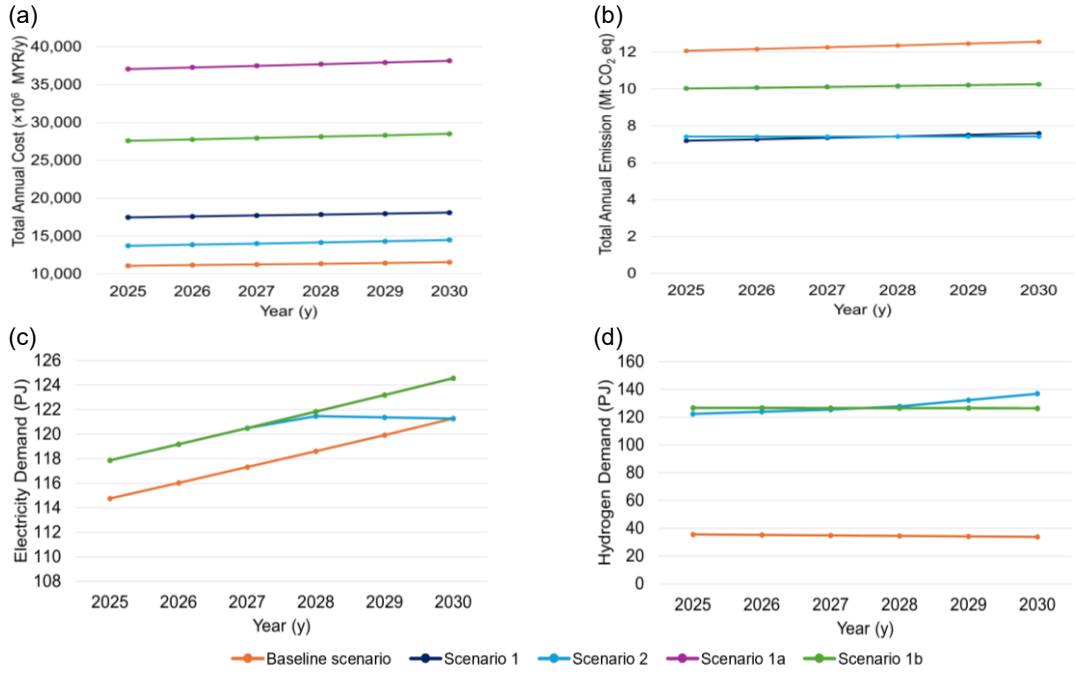


*Figure 2: Annual results for (a) total annual cost, (b) total annual emissions, (c) annual electricity demand, and (d) annual hydrogen demand*

Under Scenario 1, all industry decarbonises, with the synthetic methane industry, semiconductor industry, and other industries choosing electricity-based technology for heating utility purposes instead of hydrogen-based technologies due to higher cost-efficiency. Grey hydrogen dominates the hydrogen supplied to all the industry sectors; the mixes shifted towards pure green hydrogen in Scenario 1a and Scenario 1b.
Under Scenario 2, there is a lot of fuel mixing except for the cement industry, ammonia production industry, and methanol industry, which adopt hydrogen technologies since 2025. For example, the steel industry will mix fossil fuel-based technologies and hydrogen-based technologies in 2025 and change to full hydrogen after that. The synthetic methane industry uses only electricity-consuming technologies until 2029, and switches to hydrogen-consuming technologies in 2030. This is because the carbon cap in this scenario is fixed for each year. Thus, when there is an available emission cap, the sector will choose technology that uses cheap fossil fuel to fulfil their utility demand so that the total cost can be kept low.

### 5.2 Sensitivity Analysis

A sensitivity analysis is done on the baseline scenario to test the robustness of the model. Five variables: hydrogen furnace efficiency, electricity tariff for industry, electric vehicle (EV) energy efficiency, fuel cell electric (FCEV) vehicles energy efficiency, grey hydrogen, and green hydrogen cost per unit are chosen for the analysis. The value of these five variables varies within $\pm 10\%$ of the variable initial value. The effect of each variable on the total annual cost in 2030 is shown in Figure 3. For a $\pm 10\%$ range, the hydrogen furnace efficiency, EV energy efficiency, and FCEV energy efficiency result in no effect on the total annual cost in 2030, as these variables and their respective technologies are not being utilised in the baseline scenario. The total annual cost is most sensitive to the electricity tariff for industry, which gives the highest change $\pm 3.632\ \%$ decrease when the electricity tariff for industry decreases and increases by 10 %. Then it is followed by the grey hydrogen cost per

unit, with the changes of total annual cost in 2030 ranging between $\pm 1.032$ % and the lowest is the FCEV energy efficiency, with a range of +0.986% and -0.807% difference.

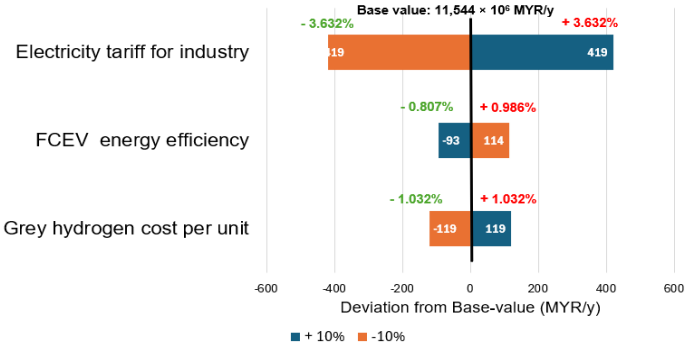


*Figure 3: Sensitivity analysis of total annual cost in 2030*

## 6. Conclusions

This study designed a linear-programming optimization model for Sarawak (2025–2030) that links utility-level demands, technology feasibility, and alternative carbon policies. From the results, it can be concluded that a carbon tax (Scenario 1) at 592 MYR/t $CO_2$ eq is required to push $H_2$ usage in industries when there is no carbon cap. The emission abatement is significant but results in a substantially higher total cost. On the other hand, a fixed-tax, minimum-binding cap pathway (Scenario 2) achieves a much lower total cost and slightly lower total emissions than Scenario 1. Besides, considering hydrogen-class emissions for the demand layer improves the green and blue hydrogen usage, but significantly increases the difficulty of decarbonising the demand layer. Thus, to motivate local hydrogen adoption, local policy should focus on the use of a moderate carbon price with a graduated, binding carbon cap. The implementation of a hydrogen fee-rebate mechanism requires more proper navigation as it results in a cleaner hydrogen mix, but harder for sectoral decarbonisation action to take place. Detailed modelling of the interaction between the local electricity producer and the hydrogen producer, and detailed transport vehicle choice selection behaviour will be considered in future work. While the hydrogen fee-rebate mechanism demonstrates potential from a policy perspective, it may not be financially self-sustaining in its current form. A comprehensive assessment of its financial structure and potential funding mechanisms will be undertaken in future studies.

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