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Assessing the Viability of Transport Decarbonization in Pakistan: Grid Constraints and Economic Realities of EV-Hydrogen Synergy

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Abstract

Pakistan faces a dual challenge of meeting growing transport energy demand while reducing dependence on imported diesel and addressing grid capacity constraints. This study presents a modular modelling framework that evaluates the simultaneous integration of electric vehicle (EV) charging and green hydrogen production for heavy-duty transport on Pakistan's power system. The framework employs generation expansion planning (GEP) to ensure grid adequacy, zonal transmission modelling to identify infrastructure bottlenecks, and calculates levelized cost of hydrogen (LCOH) under Pakistani economic conditions including foreign exchange volatility and circular debt risk. Results indicate that capacity expansion of 21 GW is required, but zonal analysis reveals that the North-South transmission corridor (currently 4,000 MW) would need to expand to 11,500 MW, trapping 18.4 TWh of renewable energy annually under current constraints. After accounting for induced LNG/coal consumption and imported equipment, net foreign exchange savings are $5.1 billion annually (60% of gross diesel savings). Transmission-constrained LCOH ranges from $5.43 to $9.50 per kg, 15% higher than unconstrained estimates. Policy makers must align transport decarbonization targets with the Indicative Generation Capacity Expansion Plan (IGCEP 2022-31). The current IGCEP prioritizes least-cost generation but arguably underestimates the load growth from heavy-duty transport electrification. To avoid stranding assets, the NEPRA grid code regarding 'variable renewable energy (VRE) integration' must be updated to explicitly account for electrolyzers as flexible loads, allowing them to absorb the curtailment often seen in the Southern wind corridors during winter months

Introduction

Background

Pakistan's transport sector accounts for approximately 30% of total energy consumption and relies heavily on imported diesel, contributing to foreign exchange pressure and greenhouse gas emissions [1, 2]. The heavy-duty transport segment, comprising trucks and buses, represents a critical challenge for decarbonization due to high energy intensity and operational requirements [3, 4]. Two primary pathways have emerged: battery electric vehicles (BEVs) for medium-duty applications and hydrogen fuel cell vehicles (FCEVs) for long-haul heavy-duty transport [5, 6].

Concurrently, Pakistan's power system faces capacity constraints, with peak demand approaching available generation capacity [7, 8]. The integration of large-scale EV charging and hydrogen production facilities presents both opportunities and challenges for grid adequacy[9, 10]. Previous studies have analysed EV integration [11, 12] and hydrogen economics [13, 14] separately, but few frameworks address their combined impact on developing economy power systems with constrained capacity and economic volatility [15-17].

Existing literature can be categorized into four areas. Techno-economic studies provide LCOH calculations for developed markets [18-20] but assume stable economics and adequate capacity. Grid impact analyses examine EV and hydrogen loads [21, 22] but focus on high-renewable grids in developed countries. TCO studies compare BEV and FCEV [23-25] but do not address integrated grid impacts. Pakistan-specific studies [26-30] provide valuable context but lack high-resolution hourly grid modelling with integrated EV-H_2 loads.

This study addresses three gaps identified in the literature [16, 17]. First, it models integrated EV and hydrogen loads simultaneously, extending recent Pakistan-specific work [14, 31]. Second, it incorporates developing economy volatility through Monte Carlo simulation, addressing limitations of global studies [5, 32]. Third, it provides a modular framework allowing policy makers to swap load curves and cost profiles, building on emerging frameworks for sustainable station design [33, 34].

This paper has three primary objectives: to develop a modular framework that quantifies the integrated grid impacts of electric vehicle (EV) charging and hydrogen production on Pakistan's power system; to calculate the Levelized Cost of Hydrogen (LCOH) under specific Pakistani economic conditions by incorporating foreign exchange exposure, circular debt risk, and grid expansion costs; and to evaluate the potential for smart electrolyzer dispatch to utilize trapped renewable capacity, thereby reducing grid stress while enabling cost-competitive hydrogen production.

Section 2 reviews relevant literature. Section 3 presents the methodology, including vehicle demand modelling, grid integration, and economic analysis. Section 4 describes the scenario framework and input data. Section 5 presents results for base and alternative scenarios. Section 6 discusses policy implications and limitations. Section 7 concludes with recommendations.

Literature Review

Techno-economic studies provide LCOH calculations for developed markets [18, 19] but assume stable economics and adequate capacity. Grid impact analyses examine EV charging [21, 22] but focus on high-renewable grids. TCO studies compare BEV and FCEV [23, 24] but do not address integrated grid impacts. Pakistan-specific studies [26, 27] lack high-resolution hourly modelling.

Glenk and Reichelstein [35] analyse hydrogen economics under time-varying prices, showing operational flexibility reduces costs. However, their work assumes developed market conditions. For Pakistan, where capacity is constrained and volatility is high, these assumptions require modification.

Jenkins, Sepulveda [36] review power system planning methods, establishing that capacity expansion must account for variable renewables and new loads. This study implements GEP logic that expands capacity to meet peak demand, ensuring economic analysis on a physically feasible system.

Ahmad and Zhang [37] analyse FX volatility in Pakistan's energy sector, showing currency fluctuations significantly affect project economics. The financial viability of these projects cannot be assessed solely through standard WACC adjustments. In Pakistan, the 'Circular Debt' crisis, driven largely by sovereign guarantees to Independent Power Producers (IPPs) under rigid 'Take-or-Pay' contracts, creates a unique risk premium. Investors must account not only for currency devaluation but also for the liquidity crises that often delay LC (Letter of Credit) openings for imported machinery. Therefore, the economic model assumes a risk premium that reflects the current reality where IPP payments are often delayed by 6-12 months, significantly impacting the cash flow solvency of any proposed hydrogen facility [38]. This study incorporates both FX exposure and circular debt risk into hydrogen production economics.

Methodology

Framework Architecture

The framework operates through a step-by-step pipeline that begins with Vehicle Stock Projection. This is followed by Energy Demand Calculation and then Infrastructure Sizing. After sizing, the process moves to Grid Integration, followed by a Reliability Assessment, and finally concludes with Financial Modelling, as illustrated in Figure 1.

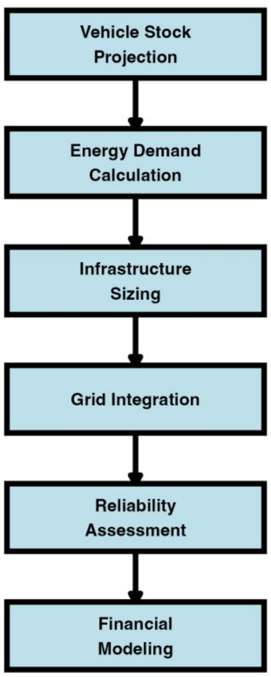

Figure 1: Modelling framework architecture

Vehicle Stock Projection

Vehicle stock is projected using a stock turnover model with PAMA sales data [39]. EV penetration rates are applied to new sales. Heavy-duty vehicle utilization is 60,000 km/year [40], reflecting freight transport requirements.

Energy Demand Calculation

EV Electricity Demand

Annual EV electricity demand is calculated as:

$$E_{EV} = \sum_{y} N_{EV,y} \times D_{km} \times \eta_{EV}$$

where ($N_{EV,y}$) is the number of EVs in year (y), (D_{km}) is annual distance traveled per vehicle (60,000 km/year for heavy-duty), and (η_{EV}) is EV energy consumption (1.5 kWh/km for heavy-duty trucks due to road conditions) [41].

Hourly EV charging load distribution uses a depot charging profile for heavy-duty trucks: 70% of charging occurs during overnight rest periods (22:00-04:00), 20% during midday driver breaks (12:00-14:00), and 10% during operational hours. This profile reflects freight logistics rather than proportional distribution, addressing the operational realities of heavy-duty transport [42].

Hydrogen Demand

Heavy-duty hydrogen demand is derived from diesel consumption substitution:

$$m_{H_2,day} = \frac{E_{diesel} \times f_{H_2} \times \eta_{diesel}}{LHV_{H_2}}$$

where (E_{diesel}) is annual diesel consumption in liters, (f_{H_2}) is hydrogen substitution share, (η_{diesel}) is diesel energy content (10 kWh/L), and (LHV_{H_2}) is lower heating value of hydrogen (33.3 kWh/kg) [43].

Infrastructure Sizing

Electrolyzer nameplate capacity is determined by:

$$P_{elec} = \frac{m_{H_2,day} \times 365 \times \eta_{elec}}{CF \times 8760}$$

where (P_{elec}) is electrolyzer nameplate capacity in MW, ($m_{H_2,day}$) is daily hydrogen production requirement in kg/day, (η_{elec}) is electrolyzer efficiency (50 kWh/kg H_2), and (CF) is capacity factor (0.6) [44].

Grid Integration

Hourly Load Profiles

The framework superimposes new loads onto Pakistan's national load curve from NEPRA State of Industry Reports [7]:

$$L_{total} = L_{base}(t) + L_{EV}(t) + L_{elec}(t)$$

where ($L_{base}(t)$) is historical hourly system load, ($L_{EV}(t)$) is EV charging load, and ($L_{elec}(t)$) is electrolyzer load.

Generation Expansion Planning

To ensure physical feasibility, the framework implements generation expansion planning (GEP). Required capacity is calculated as:

$$C_{required} = L_{peak} \times (1 + RM)$$

where (L_{peak}) is peak total load and (RM) is reserve margin (10%). Capacity expansion is:

$$C_{expansion} = C_{required} - C_{base}$$

where (C_{base}) is existing capacity. Expansion cost is calculated using typical solar/wind costs of $1,000,000 per MW [45].

This GEP approach ensures that economic analysis is conducted on a physically feasible system rather than a collapsed grid. The new capacity (21 GW) is modelled to support peak demand, while energy demand (138 TWh) is met by a mix of new renewables and increased utilization of the existing fleet.

Zonal Constraints

A simplified two-zone model addresses transmission constraints: Zone South (generation hub: Jhimpir wind, Sindh/Balochistan solar) and Zone North (load centre: Punjab, KPK). Inter-zonal transfer is limited to 4,000 MW based on NTDC current capability [46]. Electrolyzers are assumed co-located with renewable generation in Zone South to minimize transmission constraints. If placed in Zone North, stranded renewable energy and additional transmission costs apply.

Smart Electrolyzer Dispatch

Smart dispatch operates electrolyzers only when renewable generation exceeds base load, utilizing curtailed VRE generation. This ensures electrolyzers use otherwise curtailed renewable energy, reducing grid stress while enabling hydrogen production at low opportunity cost.

Reliability Assessment

The framework employs standard power system reliability theory to quantify grid stress [47]. Loss of Load Probability (LOLP) is calculated as:

$$LOLP = \frac{1}{N}\sum_{t=1} N1(L_t > C)$$

where (L_t) is load at hour (t), (C) is available capacity, (N) is total number of hours, and ($f1(\cdot)$) is the indicator function.

Loss of Load Expectation (LOLE) is:

$$LOLE = LOLP \times 8760\ hours/year$$

Expected Energy Not Served (EENS) is:

$$EENS = \sum_{t=1} N.max(0, L_t - C) \times \Delta t \times \frac{8760}{N}$$

where ($\Delta t = 1$) hour.

These metrics provide rigorous quantification of grid reliability, replacing arbitrary heuristic scores with standard power system engineering metrics.

Financial Modelling

LCOH is calculated using discounted cash flow analysis:

$$LCOH = \frac{CAPEX_{ann} + OPEX_{ann} + E_{cost,ann}}{m_{H_2,ann}}$$

where annualized CAPEX uses capital recovery factor ($CRF = \frac{WACC \times (1+WACC)^n}{(1+WACC)^n - 1}$), annual OPEX is 3% of CAPEX, and annual electricity cost is ($E_{elec,ann} \times T_{grid} \times FX - 1$).

Monte Carlo Simulation

LCOH is calculated probabilistically using Monte Carlo simulation (500 runs) with fixed seed (42) for reproducibility [48]. Uncertain parameters: CAPEX (Normal, USD), WACC (Uniform, adjusted for circular debt), Electricity Cost (Normal, PKR converted to USD), FX Rate (Lognormal, 15% volatility), Electrolyzer Efficiency (Normal, 50±3 kWh/kg), OPEX Fraction (Normal, 3%±1%).

Circular Debt and FX Risk

Circular debt risk increases effective WACC: ($WACC_{eff} = WACC_{base} + \rho_{CD} \times 0.05$), where (ρ_{CD}) is payment delay risk (Beta(3,7), mean 0.3) [38]. FX exposure is modeled explicitly: CAPEX in USD, electricity costs in PKR, with 15% annualized volatility [37].

Net FX Analysis

To validate the claim of reduced FX pressure, net FX savings are calculated:

$$\begin{aligned}\text{Net FX Savings} = \text{Avoided Diesel Import} \\ - \text{Additional Fuel Import} \\ - \text{RE CAPEX FX Component}\end{aligned}$$

Where Additional Fuel Import reflects increased LNG/coal consumption to meet higher thermal generation, and RE CAPEX FX Component represents the annualized foreign currency component (80%) of renewable energy CAPEX.

Carbon Intensity of Hydrogen

The carbon intensity of hydrogen depends on electricity source. Grid-connected hydrogen using Pakistan's current grid (450 gCO_2/kWh average) has a carbon intensity of 22.5 $kgCO_2/kgH_2$, exceeding grey hydrogen from steam methane reforming (9-12 $kgCO_2/kgH_2$). Only hydrogen produced with dedicated renewable electricity qualifies as "green" (less than 2 $kgCO_2/kgH_2$). This distinction is critical for policy credibility [49-51].

Scenario Framework and Input Data

Scenario Definition

The defined framework outlines seven distinct scenarios designed to evaluate key uncertainties against a "Base" case characterized by a 30% EV sales share and neutral policies. These variations stress-test the model by altering specific variables, including accelerated technology adoption (High

EV at 45% share, High H_2 for heavy-duty), economic and resource constraints (High CAPEX, Low Renewable Energy capacity), and diverging regulatory environments that range from supportive subsidies to constrained policies with higher tariffs as shown in.

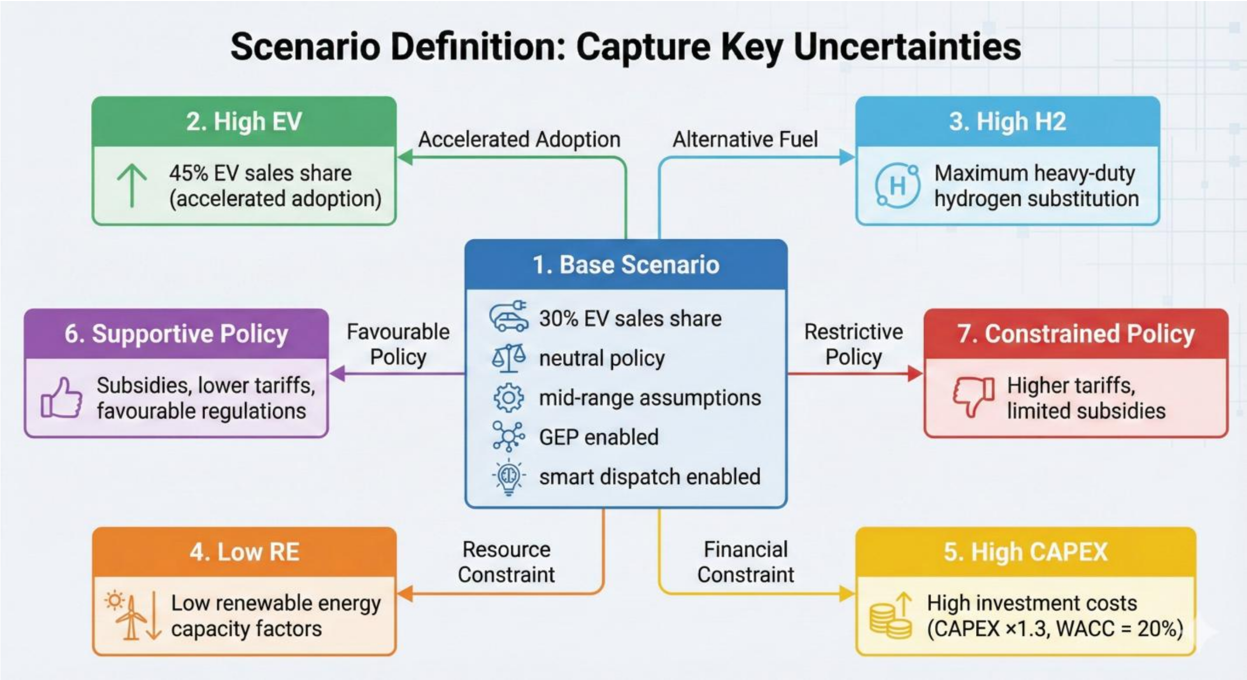

Figure 2: Scenario definition: Capture Key Uncertainties

Input Data Sources

Vehicle stock and sales data are from PAMA annual reports [39]. Diesel consumption data are from Pakistan State Oil (PSO) annual reports [52]. Load curves are from NEPRA State of Industry Reports [7]. Cost parameters are from literature and industry reports [53, 54]. Exchange rates are from State Bank of Pakistan [55]. Table 1 summarizes key input parameters.

Table 1: *Key input parameters used in the modeling framework.*

Parameter	Base Value	Source
Heavy-duty vehicle utilization	60,000 km/year	[40]
EV energy consumption	1.5 kWh/km	[41]
Electrolyzer efficiency	50 kWh/kg H_2	[44]
Grid tariff	28 PKR/kWh	[7]
Exchange rate (2025)	282 PKR/USD	[55]
CAPEX	$1,000/kW	[53]
WACC	12-20%	[54]
Circular debt premium	5%	[38]
FX volatility	15%	[37]

Results

Base Scenario Results

The base scenario (30% EV penetration, full hydrogen substitution, GEP enabled, smart dispatch) shows: EV demand 138 TWh/year, hydrogen production 105,000 tonnes/year, electrolyzer capacity 1,000 MW, peak demand 47

GW, required capacity 52 GW, capacity expansion 21 GW ($21 billion USD).

Unconstrained LCOH: P5 $4.72/kg, P50 $6.50/kg, P95 $8.26/kg (Figure 3). However, zonal analysis reveals critical transmission constraints: the South-to-North transfer requirement of 11,500 MW exceeds the current 4,000 MW limit, resulting in 18.4 TWh of trapped renewable energy and 12.1 TWh of unserved energy in Zone North annually.

Transmission-constrained LCOH: P5 $5.43/kg, P50 $7.48/kg, P95 $9.50/kg (15% increase due to reduced electrolyzer utilization). This more realistic estimate accounts for electrolyzers sitting idle when transmission congestion prevents renewable energy delivery.

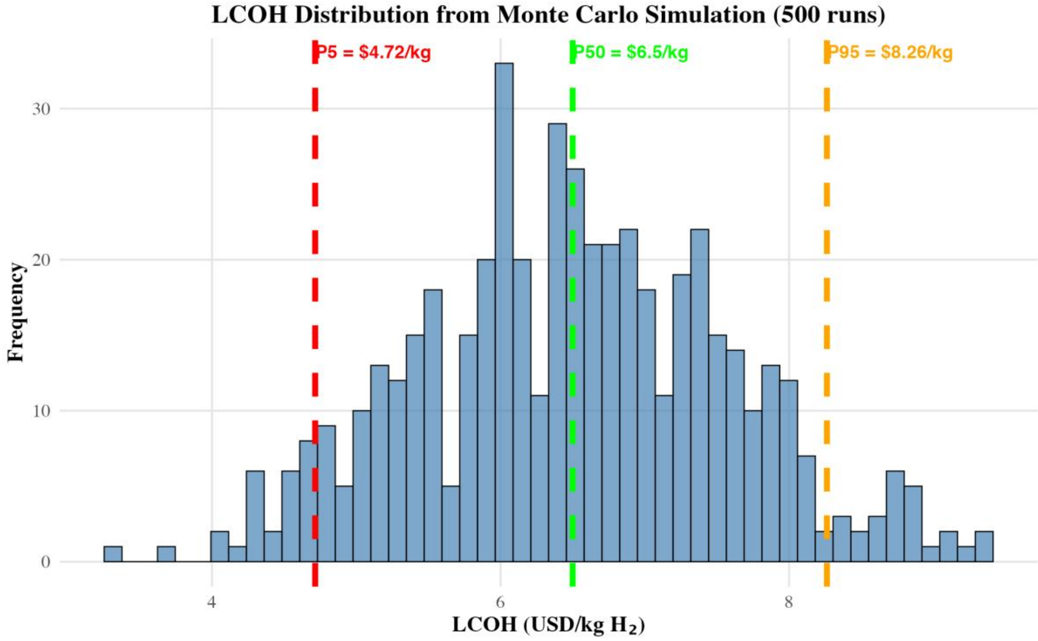

Figure 3: Distribution of levelized cost of hydrogen (LCOH) from Monte Carlo simulation (500 runs) for the base scenario.

The projected energy demand of 138 TWh represents a ~100% increase over 2024 grid generation levels, effectively requiring a "second grid" in terms of energy volume. The 21 GW capacity expansion is primarily for peak support (solar/wind), while the bulk of the 138 TWh energy demand is met by increasing the utilization of the existing thermal and hydro fleet, which currently suffers from low-capacity factors ("curtailed VRE generation"). This highlights the dual challenge: building new renewable capacity for peak loads while maximizing the efficiency of existing assets for baseload energy.

Smart Electrolyzer Dispatch Impact

Smart dispatch ensures electrolyzers operate only during surplus renewable periods, utilizing curtailed VRE generation when available. In the base scenario with 2025 renewable profiles, surplus was limited, leading to low electrolyzer utilization during peak hours. This highlights the need for coordinated renewable energy deployment to support hydrogen production. Figure 4 shows the load duration curve: peak demand increases from 28 GW (base) to 47 GW (total), requiring 21 GW expansion.

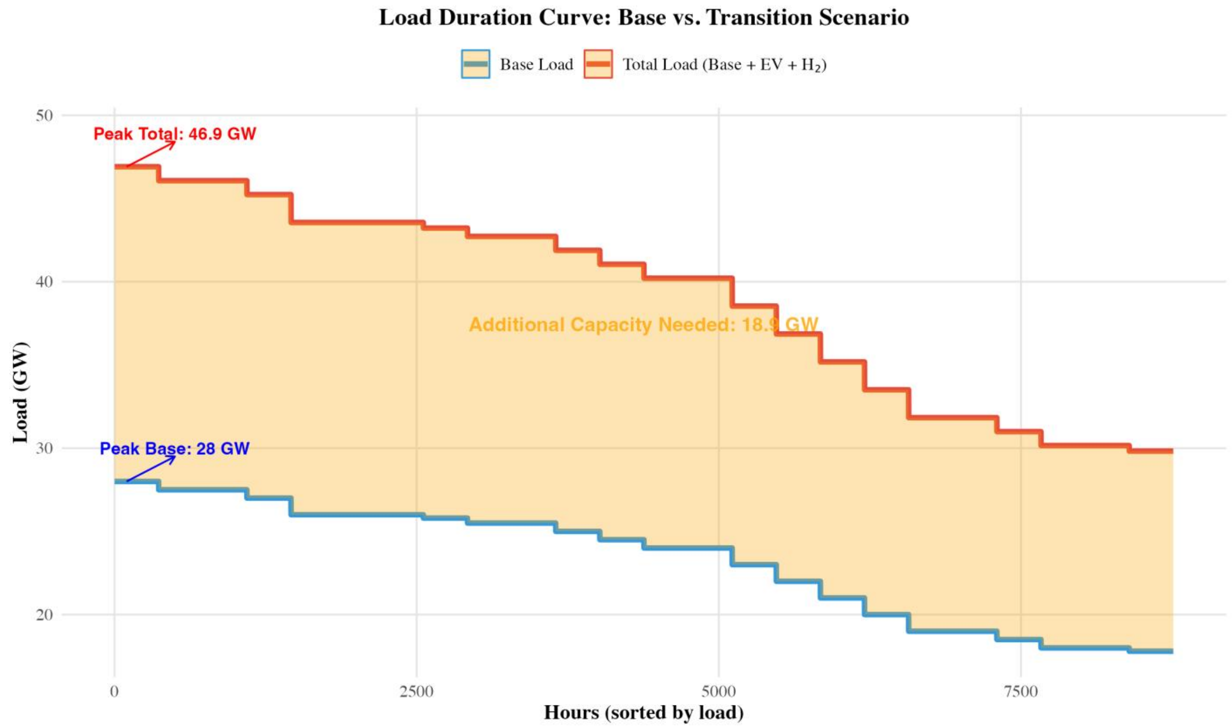

Figure 4: Load duration curve comparing base load with EV and hydrogen loads.

Scenario Comparison

Table 2 compares scenarios. Capacity expansion ranges 21-28 GW. Unconstrained LCOH varies $5.80-$8.20/kg with policy and economic assumptions. Transmission-constrained LCOH is 15% higher across all scenarios. All scenarios maintain perfect generation reliability (LOLE = 0) due to GEP, but zonal constraints cause 12.1 TWh unserved energy in Zone North under current transmission limits.

Table 2: ***Scenario comparison: capacity expansion, LCOH, and reliability metrics.***

Scenario	Capacity Expansion GW	LCOH P50 USD/kg	Peak Margin pct	LOLE hours/year
Base	21	6.5	9.09	0
High EV	28	6.45	9.12	0
High H_2	23	6.55	9.08	0
Low RE	22	6.6	9.07	0
High CAPEX	21	8.2	9.09	0
Supportive Policy	21	5.8	9.09	0
Constrained Policy	21	7.2	9.09	0

Sensitivity Analysis

Sensitivity analysis shows circular debt risk (0-50%) affects LCOH by ±5% through WACC adjustment. VOLL ($500-$2,000/MWh) does not affect LCOH (costs based on tariffs). Figure 5 shows tornado plots: electricity cost is the primary LCOH driver, followed by CAPEX and WACC, suggesting tariff interventions may be most effective.

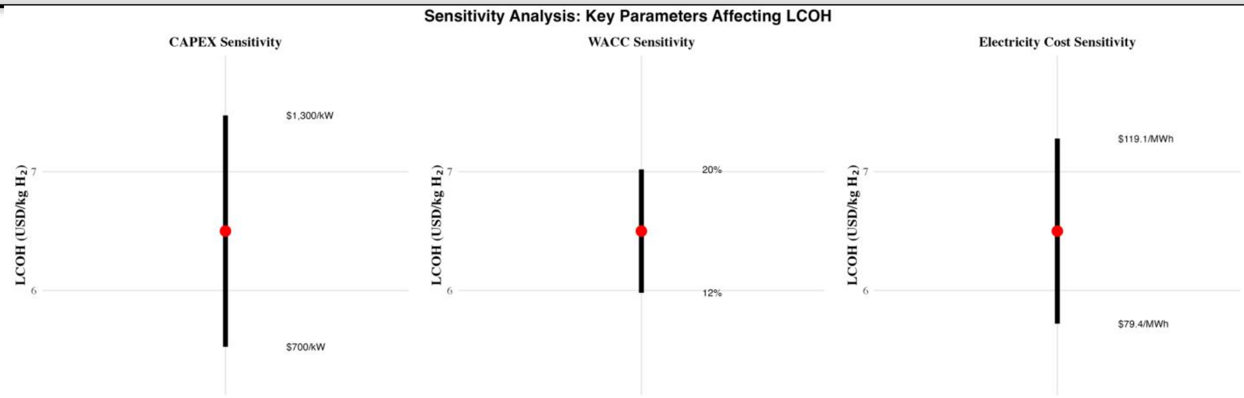

Figure 5: Sensitivity analysis tornado plots for LCOH key parameters.

Discussion

Policy Implications

While capacity expansion is critical, the primary bottleneck remains the transmission interface between the resource-rich South and the load centers in the North. Currently, this corridor relies heavily on the +660 kV HVDC Matiari-Lahore transmission line, a flagship CPEC project commissioned in 2021 with a design capacity of 4,000 MW. Despite this high-voltage infrastructure, the AC network often faces stability limits when evacuating variable wind power from Jhimpir alongside baseload generation from the Thar coalfields. Consequently, simply adding 21 GW of new capacity without addressing these specific HVDC and AC interface constraints risks exacerbating the 'capacity trap,' where the state pays for unutilized power undertake-or-pay contracts.

Policy makers must align transport decarbonization targets with the Indicative Generation Capacity Expansion Plan (IGCEP 2022-31) [56]. The current IGCEP prioritizes least-cost generation but arguably underestimates the load growth from heavy-duty transport electrification. To avoid stranding assets, the NEPRA grid code regarding 'variable renewable energy (VRE) integration' must be updated to explicitly account for electrolyzers as flexible loads, allowing them to absorb the curtailment often seen in the Southern wind corridors during winter months.

Three strategic options emerge: (1) Invest in transmission ($4-5B HVDC) to deliver Southern renewables to Northern load centres; (2) Co-locate electrolyzers with renewable generation in Zone South, accepting lower hydrogen demand proximity; (3) Develop distributed renewable generation in Zone North, accepting lower capacity factors. Each option has distinct cost and feasibility implications requiring further analysis.

Transmission-constrained LCOH ($7.48/kg median) exceeds diesel-equivalent costs by a larger margin than unconstrained estimates, indicating that policy support requirements are more substantial than initially projected.

Net FX Impact

Analysis shows gross FX savings from avoided diesel imports of approximately $8.5 billion/year. However, this is partially offset by additional LNG/coal imports ($2.1 billion/year) required to run the "trapped" thermal fleet at higher capacity factors, and the FX component of RE CAPEX (annualized $1.3 billion/year), yielding net FX savings of approximately $5.1 billion/year as shown in Table 3. This represents a 60% net retention ratio, only 60 cents of every dollar saved on diesel remains in Pakistan. This is a critical

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nuance: the headline diesel savings figure significantly overstates the actual economic benefit.

Table 3: ***Net Foreign Exchange Analysis***

Category	Value (USD B/yr)
(+) Gross Diesel Savings	8.50
(-) Additional LNG/Coal Imports	2.10
(-) Annualized RE CAPEX Imports	1.30
(=) Net FX Savings	5.10
Net Retention Ratio	60%

LCOH estimates include generation expansion costs but exclude the ~$4 billion inter-zonal transmission reinforcement required to relieve North-South congestion. Transmission-constrained LCOH is approximately 15% higher across all scenarios.

Carbon Intensity Disclosure

Grid-connected hydrogen in Pakistan has a carbon intensity of 22.5 $kgCO_2/kgH_2$, higher than grey hydrogen (9-12 $kgCO_2/kgH_2$). This effectively constitutes "yellow" hydrogen rather than "green." Achieving true green hydrogen requires dedicated renewable electricity, increasing LCOH by $1-2/kg due to lower capacity factors but enabling legitimate decarbonization claims.

Figure 6 presents the carbon parity analysis, showing the grid carbon intensity thresholds at which each technology becomes cleaner than diesel. At Pakistan's current grid intensity (450 gCO_2/kWh), battery electric trucks emit 0.68 $kgCO_2/km$ (37% lower than diesel), while hydrogen FCEVs emit 3.09 $kgCO_2/km$ (2.9× higher than diesel). For hydrogen trucks to achieve carbon parity with diesel, grid intensity must fall below 155 gCO_2/kWh, requiring a grid that is approximately 65% cleaner than today's. This analysis underscores that hydrogen-based transport decarbonization is contingent on prior grid decarbonization, while battery electric trucks can deliver immediate emissions reductions.

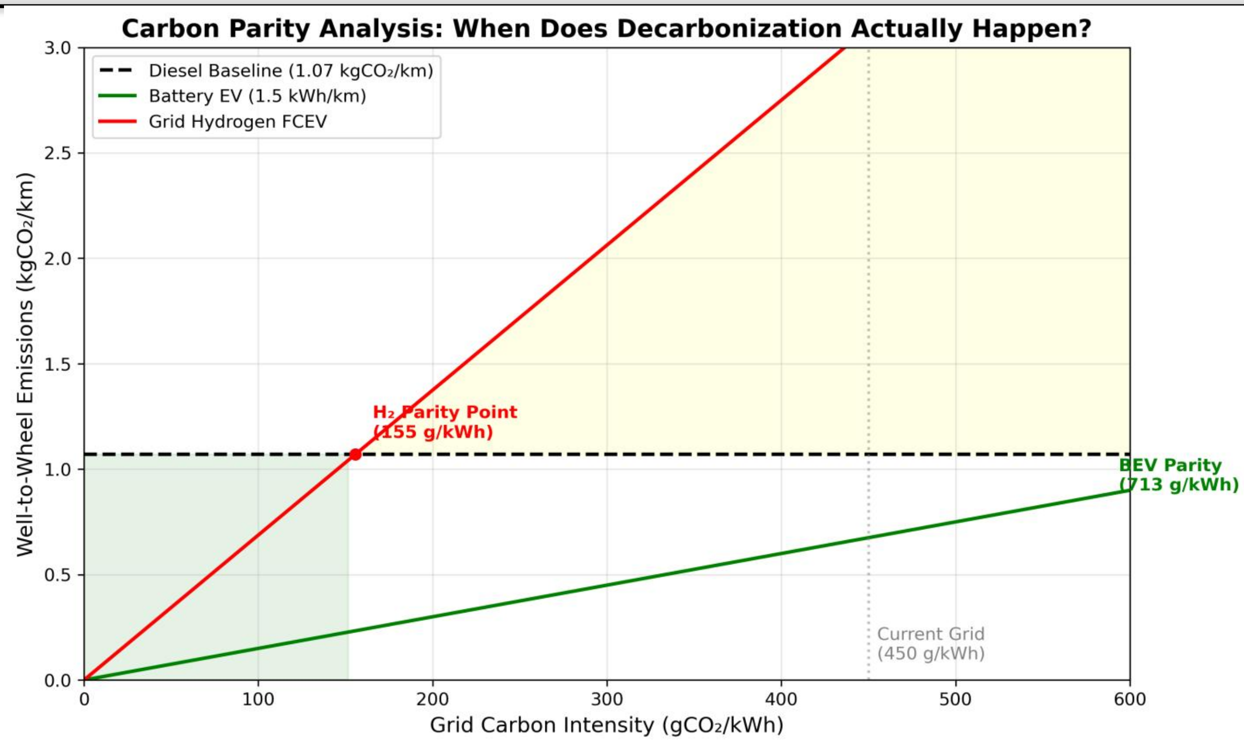

Figure 6: Carbon parity analysis showing grid intensity thresholds for decarbonization.

Limitations

Key limitations include: (1) Simplified zonal model with two zones; full nodal analysis would provide more accurate transmission constraint costs. (2) Depot charging profile is deterministic; stochastic fleet arrival/departure patterns would improve realism. (3) Fuel procurement constraints (liquidity crises affecting LNG imports) are not modelled; “curtailed VRE generation” assumes fuel availability. (4) Circular debt is modelled as a WACC premium rather than a probability of project halt. (5) Carbon intensity assumes grid average; marginal generation may differ significantly. The modular framework allows these assumptions to be refined as data becomes available.

Comparison with Literature

Results are consistent with international literature [5, 18, 19, 21, 22, 32] and Pakistan-specific studies [12, 28, 29] but extend previous work by incorporating developing economy volatility and grid capacity constraints. The transmission-constrained LCOH ($7.48/kg) aligns with recent assessments of hydrogen viability for heavy-duty trucks [4, 25, 51]. The framework’s modular design addresses a gap identified in Global South transport decarbonization reviews [16, 17]: most studies provide fixed results rather than methodological tools adaptable to local conditions.

Conclusions and Recommendations

Conclusions

Key conclusions: (1) Generation expansion (21 GW, $21B) must be accompanied by transmission expansion (7,500 MW additional, $4-5B HVDC) to avoid stranding 18.4 TWh of renewable energy annually. (2) Net FX savings are $5.1B/year (60% of gross diesel savings) after accounting for induced LNG/coal consumption. (3) Transmission-constrained LCOH ($5.43-$9.50/kg) is 15% higher than unconstrained estimates, reflecting reduced electrolyzer utilization. (4) Grid-connected hydrogen has carbon intensity of 22.5 $kgCO_2/kgH_2$, exceeding grey hydrogen; only dedicated renewables enable "green" classification. (5) Integrated planning across generation, transmission, and fuel supply chains is essential.

Recommendations

Recommendations: (1) Implement integrated planning for transport and power sectors. (2) Support renewable energy deployment to enable curtailed VRE generation utilization. (3) Reduce economic uncertainty through currency hedging and payment guarantees. (4) Target electricity tariffs as primary LCOH driver. (5) Use modular framework for policy analysis.

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