

“A TECHNICAL REVIEW OF INTEGRATED SYSTEM PLAN (ISP) 2025–35”

Policy Recommendations

Full Transparency in ISP Approval and Cost Disclosure

- Approve ISP 2025–35 only after full disclosure of year-wise tariff build-up, including CPP, EPP, TPP, transmission charges, losses, recovery gaps, and category-wise consumer impacts, alongside mandatory disclosure of all planning assumptions and subsidy implications.

Affordability Constraint and Tariff Planning Discipline

- Introduce a binding affordability constraint within IGCEP–PLEXOS optimisation, ensuring least-cost planning remains aligned with a regional industrial tariff benchmark of 8–10 US cents/kWh, while progressively reducing capacity-related burden toward Rs. 5/unit.

Demand Forecasting Reform and Structural Adjustment

- Enforce structural break-adjusted demand forecasting that incorporates observed demand contraction, rooftop solar displacement, industrial load migration, and CTBCM-driven market shifts before finalising capacity expansion plans.

Controlled Capacity Expansion and Plant Viability Standards

- Suspend approval of new generation additions unless justified under verified demand growth scenarios, supported by realistic load projections and a mandatory capacity audit requiring at least 60–65% plant load factor viability.

Scenario Analysis and Risk Stress Testing

- Mandate full scenario-wise sensitivity analysis disclosure (demand, tariff, fuel price, exchange rate, renewable penetration, and rooftop solar adoption) for all ISP investment decisions, including stress testing under low-demand and high-volatility conditions.

Alignment with Market Reforms and Demand Reality

- Align IGCEP additions strictly with verified demand growth trends and prohibit over-expansion during periods of structural demand stagnation, ensuring integration of CTBCM transition impacts into long-term planning forecasts.

Fiscal Rationalisation and Tariff Impact Management

- Require full system tariff impact disclosure, including capacity payments, transmission charges, losses, recovery gaps, and end-user tariff projections, with large-scale public investments and subsidies routed through PSDP instead of direct consumer burden.

Independent Validation and Institutional Oversight

- Require mandatory independent technical and financial evaluation of IGCEP/TSEP/ISP frameworks by third-party experts, with additional international peer review or validation by independent energy economists prior to regulatory approval.

Strengthening Regulatory Process and Stakeholder Engagement

- Ensure full regulatory compliance by confirming quorum requirements, strengthening procedural transparency, and extending structured stakeholder consultation windows (minimum 30–60 days) for technical review and feedback submission.

1. Background and Context

ISP 2025–35 represents Pakistan’s long-term least-cost generation and transmission expansion framework developed under the coordinated NEPRA–ISMO planning architecture and aligned with the Indicative Generation Capacity Expansion Plan (IGCEP) and the Transmission System Expansion Plan (TSEP). While the strategy is based on scenario-based optimization, reliability criteria, and investment sequencing, several assumptions regarding electricity demand growth, affordability, and system utilization diverge significantly from observed sectoral realities. These structural, modelling, and policy coherence gaps pose significant risks for electricity tariff sustainability, industrial competitiveness, system efficiency, and long-term energy investment optimization.

2. Key Technical Concerns

Key structural, modelling, and data-related issues in ISP 2025–35 are highlighted below. These concerns affect demand forecasting accuracy, system efficiency, and tariff sustainability.

- **Rising Capacity Expansion Despite Weak Demand Growth**

ISP 2025–35 proposes investments of nearly US\$53 billion despite persistent surplus capacity conditions within the power sector. Installed capacity increased from 39,772 MW (2021) to approximately 41,121 MW (2025), while peak demand declined from 32,801 MW (2022) to around 28,466 MW (2025). Therefore, the supply-demand gap widened to approximately 12,655 MW, signifying growing underutilization of existing generation assets. The continuation of take-or-pay contractual additions under weak demand conditions risks further expansion of fixed capacity obligations without corresponding demand absorption.

- **Weak Demand Composition Analysis**

The ISP demand framework does not adequately distinguish between productive and non-productive electricity consumption. Industrial electricity share declined from 25.5% (FY23) to 23.9% (FY25), while residential consumption remains dominant at 46% of total electricity demand. This structural shift away from productive consumption weakens least-cost demand forecasting assumptions and affects the long-term economic efficiency of expansion planning.

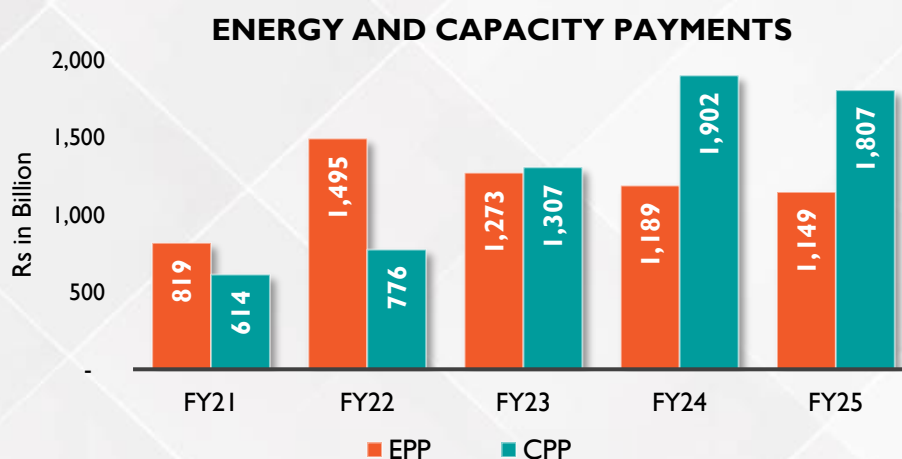
- **Demand Forecasting Diverges from Actual Consumption Trends**

Electricity generation declined from 154,056 GWh in FY22 to approximately 135,079 GWh in FY25, representing approximately a 12% contraction, despite continued capacity additions. This indicates that affordability pressures, industrial curtailment, distributed solar growth, and structural shifts in electricity consumption are not adequately reflected in the ISP forecasting framework. The industrial stakeholders argue that the existing GDP-electricity relationship embedded in planning assumptions no longer reflects actual market realities.

- **Escalating Capacity Payment Burden**

The planning framework insufficiently internalizes the rigidity of fixed system costs. Annual capacity payment obligations are estimated at approximately Rs. 1.80 trillion (FY25), reflecting a sharp growth in fixed contractual liabilities. As shown in the figure below, capacity payments (CPP) have increased far more rapidly than energy payments, rising by 194% between FY21 and FY25 (Rs 614 billion to Rs 1,807 billion), compared to a 40% increase in energy payments (Rs 819 billion to Rs 1,149 billion) over the same period. This widening divergence highlights the dominance of take-or-pay commitments over actual system usage. Consequently, further generation additions would increase non-dispatchable liabilities regardless of actual electricity consumption or dispatch outcomes, significantly raising risks of future tariff escalation and circular debt accumulation.

Figure 1: Energy and Capacity Payments over the Last Five Years

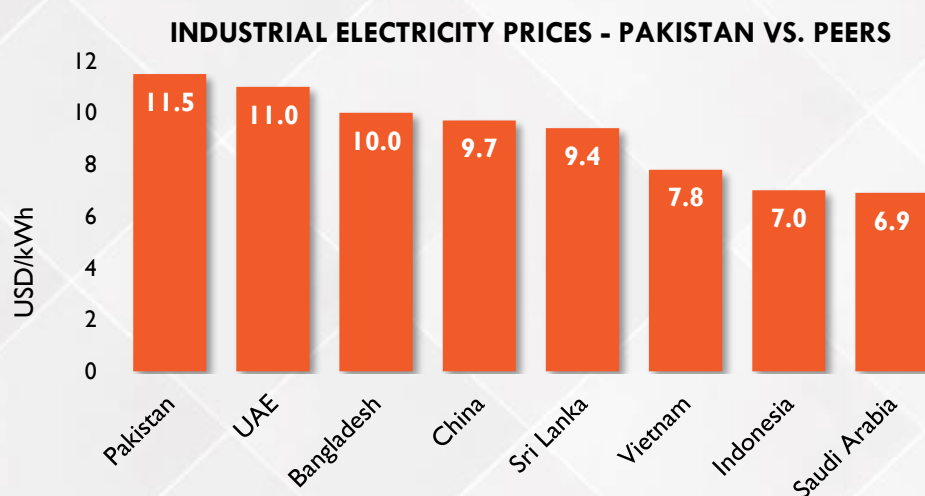


Data Source: NEPRA's State of Industry Report 2025

- **Industrial Tariff Competitiveness Remains Weak**

Industrial electricity tariffs, even after the PM's 2026 incentive package of about Rs. 4.4/unit reduction), remain around 11.5 US cents/kWh (Rs.33.0/kWh), which is still significantly less competitive than regional peers (figure 2) – Bangladesh (10.0), Vietnam (7.8), and Indonesia (7.0), showing a persistent 25%–120% cost disadvantage that weakens export competitiveness, industrial expansion, and energy-intensive production viability. While policymakers estimate that incremental plan adjustments may limit the net consumer impact to around Rs 4 per unit, industry stakeholders caution that the addition of high-cost capacity under the ISP 2025–35 could potentially push end-user tariffs up to Rs 70 per unit¹ (excluding taxes and surcharges), posing severe risks to industrial sustainability and demand retention.

Figure 2: Comparison of Industrial Electricity Tariffs – Pakistan vs. Peer Countries



Data Source: Global Petrol Prices

*The prices are the 2023–2026 average US Cents/kWh

3. IGCEP Modelling and Forecasting Concerns

- **PLEXOS-Based Modelling Limitations**

IGCEP relies on a PLEXOS-based least-cost optimization model that is highly sensitive to assumptions on GDP growth, fuel prices, tariffs, and demand elasticity, but it lacks adequate endogenous correction for affordability shocks, demand destruction, industrial relocation, and structural consumption changes. The decline in generation during FY22–FY25 further shows that current regression-based forecasting does not fully capture evolving market dynamics.

- **Overestimation Risks in GDP-Linked Demand Forecasting**

A key structural weakness in IGCEP is its heavy reliance on official GDP growth projections, which have consistently overestimated actual economic performance in recent years (see table below). Since IGCEP/ISP electricity demand forecasts are heavily GDP-driven, persistent optimism bias leads to systematic overestimation of future demand and generation needs, as projections reflect policy aspirations rather than actual macroeconomic outcomes. The GDP

¹ BR Research. (2025). No third-party validation: NEPRA's nod sought for USD 53bn ISP 2025–35. Business Recorder. <https://www.brecorder.com/news/40422128/no-third-party-validation-nepras-nod-sought-for-usd53bn-isp-2025-35>

comparison table I (2022–25) confirms consistent overestimation, highlighting structural bias in forecasting models, which raises the risk of overcapacity and inept long-term investment.

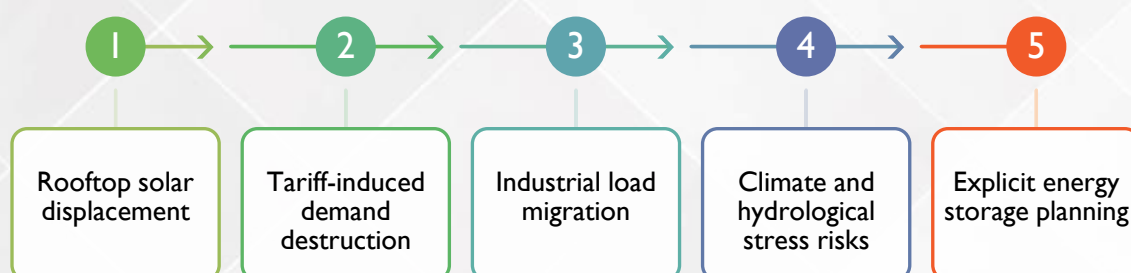
Table I: Overestimation of GDP Forecasts

Fiscal Year	Government Projected GDP Growth (%)	Actual GDP Growth (%)	Difference (% Points)	Percentage Error (%)	Direction
2022–23	5.0%	-0.21%	5.21	N/A	Overestimation
2023–24	3.5%	2.51%	0.99	40%	Overestimation
2024–25	3.6%	3.1%	0.50	16%	Overestimation

Data Source: ACJCE, 2025² and IMF (Real GDP growth)

- **Structural Weaknesses in Forecasting Assumptions**

IGCEP forecasting does not sufficiently integrate:



This weakens long-term adequacy assessments, particularly under high renewable penetration scenarios involving hydro, solar, and wind integration.

- **Scenario Bias Toward Committed Projects**

IGCEP 2025-35 scenarios remain structurally biased toward committed projects, limiting true optimization flexibility and reducing the ability to reassess capacity additions based on updated demand conditions. System load factor assumptions in IGCEP 2025-35 (70–73% historically) are inconsistent with the observed decline to about 58–60%³, indicating overestimation of utilization and demand recovery.

4. Renewable Energy (RE) Integration Challenges

- **Capacity-Centric Rather than Firm-Energy Planning**

The IGCEP 2025–35 projects a rise in RE share to 69% by 2035 from 34% in FY25, but this expansion remains capacity-centric rather than firm-energy based, with limited integration of storage, ramping capability, and dispatch flexibility. This creates a structural risk where RE additions, especially solar and wind, increase installed capacity without ensuring reliable peak contribution, raising curtailment and grid instability risks.

- **Rooftop Solar and Load Erosion**

Rapid rooftop solar penetration is increasingly reducing daytime industrial and residential grid demand. However, IGCEP still assumes grid-dominant peak supply behaviour, creating a mismatch between modelled peak demand and actual net load conditions during solar generation hours. This may result in systematic over-projection of future grid demand.

² Alliance for Climate Justice and Clean Energy. (2025). ISP 2025–35 ACJCE comments. <https://acjce.com/wp-content/uploads/2025/09/ISP-2025-ACJCE-Comments.pdf>

³ Pakistan Today. (2026). Pakistan requires up to 70,720MW more power capacity by 2035. <https://www.pakistantoday.com.pk/2026/04/24/pakistan-requires-up-to-70720mw-more-power-capacity-by-2035>

- **Distributed Solar and Storage-Driven Demand Displacement**

The ISP/IGCEP demand framework significantly underestimates the structural impact of distributed solar and storage adoption on future grid demand. Pakistan imported an estimated 38–45 GW of solar panels during 2022–2025, with nearly 8–12 GW⁴ conservatively deployed in off-grid systems, while grid electricity sales declined by around 10% in 2023 and a further 2.8% in 2024⁵. By December 2024, net-metered connections exceeded 156,000, with installed capacity crossing 4.1 GW⁶. Despite this structural shift, IGCEP continues to treat distributed solar primarily as supply-side capacity rather than permanent demand displacement, resulting in overstated future load projections and weak alignment with evolving consumer behaviour, storage adoption, and changing time-of-use demand patterns.

5. Transmission System Expansion (TSEP) Concerns

- **Transmission Planning and Generation Mismatch**

TSEP planning remains reactive rather than fully co-optimized with generation expansion, creating risks of timing mismatches, congestion, and inefficient evacuation of power from key corridors. According to the PRAC research⁷ titled Correcting Course: Pakistan's Economic Reset (Energy Chapter), the TSEP framework, despite reporting around 82% physical progress (Dec 2024), continues to face significant execution and coordination constraints, including underutilization of the 4,000 MW HVDC Matiari–Lahore transmission line, which has resulted in system inefficiencies and financial losses due to South–North transfer bottlenecks.

- **Transmission Delays and Coordination Gaps**

The plan also reflects delays in the completion of key evacuation corridors, including the Dasu and the Mohmand hydropower transmission links, the Gwadar network reinforcements, and interconnections for K-2/K-3 nuclear plants, which continue to lag behind generation commissioning schedules. These challenges are compounded by persistent generation–transmission timing mismatches, driven by procurement delays, weak inter-agency coordination between planning and executing entities, reliance on outdated system studies, and limited grid digitalization, collectively constraining efficient power evacuation and reducing overall system optimization and reliability.

6. Institutional and Governance Fragmentation

PRAC appreciates the intent behind ISP 2025–35 as a step toward integrating IGCEP and TSEP into a unified planning framework; however, this integration has not yet translated into effective operational coordination. The separation between generation planning and transmission execution further results in uncoordinated project sequencing, increasing risks of stranded assets, inefficiencies & sub-optimal system utilization. Institutional fragmentation between NEPRA, ISMO, NTDC, and planning/execution entities continues to produce inconsistent demand assumptions, overlapping projects, and fragmented planning instruments (IGCEP, TSEP, ISP), weakening least-cost optimization and investment sequencing efficiency.

⁴ Institute for Energy Economics and Financial Analysis (IEEFA). (2023). Pakistan solar and battery market outlook. Cleveland: IEEFA.

⁵ Janjua, Z. Z. (2025, July 17). Pakistan's quiet solar rush puts pressure on national grid. The Japan Times. <https://www.japantimes.co.jp/environment/2025/07/17/energy/pakistan-solar-national-grid/>

⁶ Alliance for Climate Justice and Clean Energy. (2025). ISP 2025–35 ACJCE comments. <https://acjce.com/wp-content/uploads/2025/09/ISP-2025-ACJCE-Comments.pdf>

⁷ PRAC. (2026). Correcting Course: Pakistan's Economic Reset. <https://www.prac.org.pk/pakistan-policy-dialogue>

7. Stakeholders' Input

Stakeholder consultations highlighted major concerns over Pakistan's overcapacity, rising tariff burden, weak transparency, and the risk of further demand erosion under the ISP framework.

Installed Capacity– Demand Imbalance and Rising Capacity Charges

Stakeholders highlighted that Pakistan's current installed generation capacity significantly exceeds both transmission capacity and peak demand (below 30,000 MW), yet the system already carries capacity payments of around Rs. 16/unit, reflecting the structural mismatch between demand and capacity. Concerns were raised that recent changes in net metering and captive power policies may not shift consumers back to the grid; instead, rising tariffs are encouraging further migration toward rooftop solar, battery storage, and biomass-based self-generation, potentially reducing future grid demand even further.

Transparency Gaps in ISP Approval and Planning Assumptions

Stakeholders also noted serious transparency gaps in the ISP approval process, including non-disclosure of key financial and operational parameters such as EPP, CPP, total power purchase cost (TPP), category-wise consumer tariff impacts, exchange rate assumptions, DISCO-wise demand projections, transmission losses, recovery shortfalls, and financing structures.

It was further pointed out that the ISP hearing process was conducted without full regulatory quorum, raising concerns over procedural legitimacy.

Procedural Limitations and Lack of Independent Validation

Additional concerns include lack of sufficient time for stakeholder review, absence of independent technical and financial validation, and the approval of large-scale generation additions despite stagnant demand trends, which may further intensify circular debt and idle capacity costs. Stakeholders warned that planned additions of around 20,000 MW risk exacerbating overcapacity unless demand-side reforms are implemented first.

Market Reform Pressures and Demand Erosion Risks

It was also highlighted that ongoing reforms such as CTBCM (initial quota ~800 MW) are likely to redirect industrial consumers toward competitive markets, potentially reducing grid demand further.

In this context, stakeholders emphasized that IGCEP and ISP should not proceed without independent expert validation, international peer review, and full transparency of assumptions.

Tariff Affordability and Need for Capacity Cost Rationalization

Finally, it was stressed that current average electricity tariffs include approximately Rs. 16/unit capacity charges, which are already unaffordable, and future planning must introduce a binding cap on capacity-related burden, reducing it to Rs. 5/unit, to restore planning discipline and ensure long-term affordability and system sustainability.

8. Conclusion

Pakistan's power sector planning framework requires a transition from capacity-centric expansion toward affordability-driven, demand-responsive, and fully integrated system optimization. Without recalibration of forecasting assumptions, institutional coordination mechanisms, and tariff sustainability considerations, ISP 2025–35 risks intensifying surplus capacity, fixed cost burdens, and long-term industrial competitiveness challenges. A revised planning framework grounded in realistic demand modelling, transparent tariff impact analysis, and integrated generation-transmission coordination is essential to ensure sustainable and economically viable power sector development.