Hydrological Uncertainty and its Tariff Implications: Rethinking Power Purchase Pricing for Bhutan Power Sectors

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Abstract
Bhutan's electricity tariff determination is based on forecasted electricity generation and demand under a cost-plus regulatory framework. However, hydrological variability has resulted in deviations between forecasted and actual hydropower generation, affecting power purchase prices (PPP), Bhutan Power Corporation Limited (BPC) cost recovery, and tariff stability. The power purchase price accounts for approximately 60% of the total cost for BPC. Although the Tariff Determination Regulation (2025) introduced a quarterly Power Purchase Price Adjustment (PPPA) mechanism, its effectiveness in addressing short-term variations has not been empirically evaluated. This research studies the implications of hydrological conditions, measured by river inflow, together with deviations between forecasted and actual hydropower generation and electricity demand on PPP during Bhutan's 2022–2025 tariff period. Historical monthly and annual data obtained from the Electricity Regulatory Authority (ERA), Bhutan Power Corporation Limited (BPC), and Druk Green Power Corporation Limited (DGPC) were analyzed using comparative analysis, year-wise and month-wise trend analysis, Pearson correlation analysis, and a historical simulation of the PPPA mechanism. The research study shows that the actual average PPP increased from the approved forecasted of Nu 1.60/kWh to Nu 1.78/kWh, resulting in an estimated additional electricity procurement cost of approximately Nu 3 billion. Pearson correlation analysis revealed a very strong positive relationship between actual river inflow and hydropower generation ($r = 0.952$, $p < 0.001$) and a strong negative relationship between actual hydropower generation and PPP ($r = –0.810$, $p < 0.001$). In contrast, generation variation showed a moderate positive relationship with PPP ($r = 0.365$, $p = 0.028$), while demand variation showed no statistically significant association. Month-wise analysis further revealed that reduced hydropower generation during the lean season increased reliance on higher-cost electricity purchase, resulting in substantial PPP variations. The findings show that hydrological conditions influence power purchase prices indirectly through their effect on hydropower generation and the electricity purchase mix. The study recommends evaluating a monthly PPPA mechanism, differentiated power purchase pricing, and greater integration of solar photovoltaic systems to improve tariff responsiveness, cost recovery, and the long-term resilience of Bhutan's electricity sector.

***Key words**: Power Purchase Price, Hydrological Uncertainty, River Inflow, Demand, Electricity Tariff, Power Purchase Adjustment, Cost-plus Tariff, Generation, Procurement Cost.*

1. INTRODUCTION

Bhutan’s electricity sector is almost entirely dependent on renewable hydropower, with an installed capacity of 3,490MW as of June 2025, representing approximately 11% of the country’s techno economic hydropower potential. In comparison, installed capacity of solar and wind capacity remains limited at about 6MW (National Energy Policy 2025, 2025). While this clean energy system has enabled Bhutan to maintain a low-carbon electricity sector, its heavy reliance on run-of-river hydropower makes electricity generation highly vulnerable to hydrological uncertainty.

Hydrological uncertainty refers to variations in water availability caused by changes in rainfall, snowmelt, glacier melt and river discharge. Climate change has intensified these uncertainties by altering temperature and precipitation patterns, accelerating glacier and snowmelt, and changing the magnitude and seasonal distribution of river flows. As a result, hydropower generation has become increasingly variable, particularly in mountainous countries such as Bhutan, where electricity production depends directly on river inflows. Studies suggest that Bhutan is likely to experience greater seasonal fluctuations in river flows, with lower water availability during dry periods and higher flows during the monsoon season (Yangzom & Choden, 2021). These changes increase uncertainty in electricity generation and long-term energy planning.

Bhutan's domestic electricity tariffs are determined based on the (Electricity Act of Bhutan 2001, 2001), (Domestic Electricity Tariff Policy, 2016) and (Tariff Determination Regulation, 2025). The country adopts a cost-plus tariff methodology, under which electricity tariffs are determined using forecasted electricity generation, electricity demand, prudent operating costs, capital investment, and an approved rate of return over a three-year tariff period. The retail tariff consists of two main components: the Power Purchase Price (PPP) and the network cost.

Under this framework, deviations between forecasted and actual hydropower generation and electricity demand changes the electricity procurement mix and can increase the weighted average PPP. During the 2022–2025 tariff period, these deviations resulted in an estimated additional power procurement cost of approximately Nu 3 billion. Since power procurement accounts for approximately 60% of BPC's total operating costs, even relatively small forecast deviations can significantly affect cost recovery and tariff stability (BPC Tariff Review Report 2022 to 2025, 2022).

Electricity utilities worldwide adopt tariff adjustment mechanisms to recover fluctuations in in fuel or power purchase costs while maintaining financial sustainability. Although Bhutan introduced the quarterly Power Purchase Price Adjustment (PPPA) mechanism under the Tariff Determination Regulation (2025), its effectiveness in responding to short-term procurement cost variations has not been empirically evaluated. Previous studies have primarily examined hydropower development, climate change, and energy policy, with limited attention given to the effects of hydrological uncertainty on power purchase prices, cost recovery, and tariff adjustment mechanisms. Consequently, evidence to support future tariff reforms in Bhutan remains limited.

To address this research gap, this study examines the implications of hydrological uncertainty on power purchase prices during Bhutan's 2022–2025 tariff period using historical monthly data on river inflow, hydropower generation, electricity demand and power purchase prices. Specifically, the study aims to:

(i) examine the relationship between river inflow and hydropower generation;
(ii) assess the impact of deviations between forecasted and actual hydropower generation and electricity demand on power purchase prices;
(iii) evaluate the relationships among river inflow, hydropower generation, generation variation, demand variation and power purchase prices using comparative analysis and Pearson correlation analysis;
(iv) assess the adequacy of the existing quarterly PPPA mechanism in responding to procurement cost variations; and
(v) recommend regulatory measures to improve tariff responsiveness and strengthen the Bhutan's electricity tariff framework under increasing hydrological uncertainty.

The study contributes to the growing literature on electricity tariff regulation by providing empirical evidence on how hydrological uncertainty influences power purchase prices, procurement costs and cost recovery under Bhutan's cost-plus tariff framework. The findings provide practical insights for policymakers and regulators to strengthen tariff regulation, improve the financial sustainability of BPC, and support Bhutan's transition towards a more resilient and diversified renewable energy system.

2. LITERATURE REVIEW

2.1 Hydrological uncertainty and hydropower generation

Hydropower is one of the most climate-sensitive sources of electricity because its generation depends directly on the water availability.

Hydrological uncertainty refers to the variability and unpredictability of water availability resulting from changes in rainfall, snowfall, glacier melt, river discharge and catchment runoff. Climate change is altering precipitation patterns, increasing temperatures and accelerating glacier retreat, leading to greater seasonal variability in river flows and increasing uncertainty in water availability for hydropower generation. These impacts are particularly significant in mountainous regions where river systems are strongly influenced by monsoon rainfall and glacier melt (Yangzom & Choden, 2021).

Bhutan is identified as exceptionally vulnerable to climate change impact, affecting the hydrological regime and electricity generation. Climate change is expected to alter Bhutan's hydrological regime through increasing temperatures, changing precipitation patterns and accelerated glacier retreat. The studies demonstrate that the economic consequences of hydrological variability are becoming increasingly evident in Bhutan. Hydropower generation declined by approximately 10% in 2018 because of unfavorable hydrological conditions, resulting in a reduction of more than 16% in electricity exports. More recently, domestic electricity demand has continued to increase while generation from run-of-river plants declines substantially during the lean season, requiring seasonal electricity imports from India (Gyeltshen, 2025). Similarly, recent energy sector reports indicate that peak electricity demand exceeded firm generation capacity by more than 130% in 2023 and 65% in 2024 as shown in the Fig.1 below, further increasing reliance on imported electricity during periods of low hydropower generation (Energy Sector in Bhutan, 2025).

These observations are consistent with findings reported by DGPC, which show that lower river flows during the lean season have reduced hydropower generation and increased electricity imports in recent years (DGPC Annual Report 2023, 2023). Such trends demonstrate that hydrological uncertainty has become an increasingly important operational and economic challenge for Bhutan's electricity sector.

Although hydropower generation is regarded as a controllable electricity source, hydrological conditions especially water runoff patterns and other related factors impact its generation capability. These conditions are mainly influenced by rainfall, and in rivers basins affected by snow accumulation and melting, temperature variations. Annual variation in hydrology can lead to seasonal operational patterns in hydropower, particularly in run-of-river plants (Energy Agency, 2021).

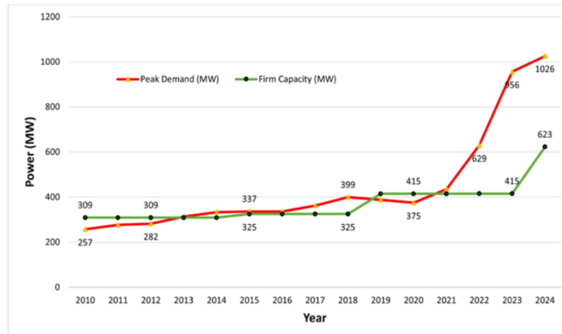

Fig. 1: *Peak demand and firm capacity*

Hydrological uncertainty is commonly discussed in relation to climate resilience and water resource management not on its implications for electricity tariff regulation. Most previous studies have focused on the physical impacts of climate change on river flows, hydropower generation or reservoir operation, whereas relatively few have examined how changes in hydrological conditions affect electricity power purchase price and tariff stability. For example, one of the study results indicate that while certain seasons may receive increased streamflow, overall hydropower potential would decline in the future during the lean seasons. Moreover, uncertainties in streamflow projections do not often lead to proportional changes in hydropower generation(Upadhyay et al., 2022). Similarly, (Gyeltshen, 2025) argued that Bhutan's continued dependence on run-of-river hydropower increases the country's exposure to climate-induced hydrological variability and highlighted the importance of improving the resilience of the electricity sector through better planning and renewable energy diversification.

While these studies demonstrate that hydrological conditions influence hydropower generation, they provide limited evidence on the economic implications of hydrological uncertainty, particularly its effects on electricity procurement costs, power purchase prices, and tariff stability. In regulated electricity markets such as Bhutan, changes in hydropower generation alter the electricity procurement mix, resulting in differences between forecast and actual power purchase prices. Understanding these relationships is therefore important for evaluating whether existing tariff mechanisms adequately respond to procurement cost variations arising from hydrological uncertainty.

Recognizing this gap, the present study considers river inflow as a measurable indicator of hydrological conditions affecting hydropower generation. Rather than attempting to quantify climate change directly, the study evaluates how variations in actual river inflow are associated with hydropower generation and whether deviations between forecasted and actual generation subsequently influence power purchase prices. This approach provides an insight on the tariff implications of hydrological uncertainty within Bhutan's regulated electricity sector.

2.2 Regulatory economics, tariff design and hydrological risk

Electricity transmission and distribution are widely recognized as natural monopolies, requiring economic regulation to balance consumer protection with the financial sustainability of electricity utilities. Regulatory economics identifies two methods of determining the electricity tariff: cost-plus (cost-of-service) regulation and incentive-based regulation (Joskow & Sloan, 2008).

Under cost-plus regulation, utilities are allowed to recover prudent operating costs together with an approved rate of return on capital investment. This approach promotes financial stability and investment certainty, making it particularly suitable for capital-intensive electricity sectors that require substantial long-term infrastructure investment. However, because utilities are compensated for actual costs, cost-plus regulation provides relatively weak incentives for cost reduction and operational efficiency and may result in regulatory lag when actual operating conditions differ from forecasted assumptions (Joskow & Sloan, 2008).

On the other hand, the incentive-based regulation, including price-cap and performance-based regulation is to improve efficiency by allowing utilities to retain part or all of the financial benefits arising from cost reductions during the regulatory period. Rather than reimbursing actual costs, tariffs are determined using predetermined performance targets, thereby creating stronger incentives for utilities to improve productivity, reduce operating costs and enhance service quality. Nevertheless, the successful implementation of incentive regulation depends on robust regulatory institutions, reliable performance benchmarking and effective monitoring systems to ensure that efficiency gains are not achieved at the expense of service reliability or long-term investment. The paper states that neither cost-plus regulation nor incentive-based regulation is universally superior; instead, the choice of regulatory framework should reflect the institutional capacity, market structure and policy objectives of the electricity sector (Joskow & Sloan, 2008).

Bhutan currently adopts a cost-plus tariff methodology under Domestic Electricity Tariff Policy (2016) and the Tariff Determination Regulation (2025). Because electricity procurement represents the largest component of retail electricity tariffs, variations in hydropower generation caused by hydrological conditions can influence power purchase prices and, consequently, utility cost recovery, making hydrological uncertainty a significant source of regulatory risk. Under such circumstances, regulatory mechanisms that allow timely recovery of legitimate procurement costs are essential to maintain the financial sustainability of electricity utilities while ensuring tariff stability for consumers.

From a regulatory economics perspective, efficient regulation should minimize cost recovery risk by ensuring that regulated transmission and distribution utilities have a reasonable opportunity to recover efficient operating and investment costs, together with a normal rate of return. This reduces financing risk, supports long-term infrastructure investment, and maintains incentives for efficient service delivery(Brown & Sappington, 2023). Consistent with this principle, the Tariff Determination Regulation (2025) have introduced the Power Purchase Price Adjustment (PPPA) mechanism to periodically recover differences between approved and actual power purchase costs(Tariff Determination Regulation, 2025). Although the quarterly PPPA mechanism represent an important regulatory improvement, its effectiveness in responding to seasonal power purchase price variations associated with hydrological uncertainty has not been empirically evaluated.

Accordingly, this study examines whether hydrological variability influences power purchase prices under Bhutan's cost-plus tariff framework and evaluates the effectiveness of the existing quarterly PPPA mechanism in recovering procurement cost variations during the 2022–2025 tariff period.

2.3 International Practices in Managing hydrological risk and power purchase cost recovery

Countries with hydropower-dominated electricity systems adopt different regulatory approaches to manage the financial risks arising from hydrological variability and changes in power purchase price. While the specific mechanisms differ according to market structure and institutional arrangements, the common objective is to ensure utility cost recovery, maintain financial sustainability and minimize the impacts of uncontrollable variations in electricity generation on consumers.

In regulated electricity markets, periodic power purchase price adjustment mechanisms are commonly used to recover differences between forecast and actual procurement costs. For example, Indian states adopt different fuel surcharge and power purchase adjustment mechanisms to balance utility financial sustainability with consumer protection. Most states impose regulatory limits on recoverable procurement costs, ranging from 5% in Chhattisgarh, 10% in Haryana, Bihar, and Uttar Pradesh, 20% in Maharashtra, and 25% in Assam, while Madhya Pradesh, Punjab, West Bengal, Andhra Pradesh, and Kerala do not impose such limits. In contrast, Gujarat and Karnataka apply fixed per-unit adjustment limits of 10 paise/kWh. Where regulatory caps apply, procurement costs exceeding the approved limit are generally recovered in subsequent billing periods with carrying costs, although some states, including Gujarat, Karnataka, Maharashtra, and Assam, permit recovery within the same billing cycle subject to regulatory approval (Josey, 2017). Recognizing inconsistencies in these state-level practices, the Government of India amended the Electricity Rules in 2022 by introducing a standardized framework for the automatic pass-through of power procurement cost variations. Under the revised rules, procurement cost variations of up to 5% may be recovered automatically through tariffs, while higher adjustments remain subject to regulatory review. These reforms aim to ensure timely cost recovery while maintaining appropriate consumer protection (Central Electricity Authority, 2025).

Similarly, in Malaysia, the Imbalance Cost Pass-Through (ICPT) under the Incentive-Based Regulation (IBR) framework. The ICPT allows electricity tariffs to be adjusted every six months to reflect changes in fuel and electricity generation costs, ensuring timely recovery of actual procurement costs while providing transparent price signals for utilities and consumers (Khairuddin et al., 2024).

Nepal relies on long-term Power Purchase Agreements (PPAs**)** to procure electricity from independent hydropower producers and promote private investment in the sector. Given its predominance of run-of-river hydropower, electricity generation remains highly sensitive to seasonal river flow variability. Nepal has therefore strengthened its PPA and regulatory framework to improve system flexibility, enhance cross-border electricity trade and support reliable electricity supply under changing hydrological conditions. (Rose et al., 2021).

Similarly, Laos has also adopted a long-term Power Purchase Agreements (PPAs) with domestic utilities and neighbouring countries, particularly Thailand and Vietnam. The Asian Development Bank notes that Laos' hydropower sector depends heavily on the Mekong River system, high annual rainfall and mountainous topography, making electricity generation closely linked to hydrological conditions. Long-term PPAs and regional electricity trade provide revenue certainty for hydropower developers while supporting financial sustainability despite seasonal variability in water availability.(Asian Development Bank, 2019).

On the other hand, Norway adopts a competitive wholesale electricity market. Electricity prices are determined through market trading in the Nordic electricity market (Nord Pool), where hydropower producers compete alongside other generators. Seasonal variations in river inflows and reservoir levels are reflected directly in wholesale electricity prices rather than through administrative tariff adjustments. Norway's extensive hydropower storage capacity, regional electricity trading, and continuous market balancing mechanisms reduce the financial risks associated with hydrological variability while maintaining electricity security and efficient resource allocation. Although Norway's liberalized market differs substantially from Bhutan's regulated cost-plus tariff framework, its experience demonstrates how competitive electricity markets can internalize hydrological risk through market-based pricing and regional power trading instead of periodic power purchase price adjustments (-International Energy Agency, 2022a).

Unlike Norway, Tajikistan has not adopted a competitive wholesale electricity market. Instead, the electricity sector remains largely state regulated, with ongoing reforms focused on unbundling the vertically integrated utility, establishing an independent electricity regulator, gradually increasing electricity tariffs to cost-reflective levels and expanding regional electricity trade. These reforms aim to improve financial sustainability and energy security in a hydropower-dependent electricity system that remains vulnerable to seasonal hydrological variability (-International Energy Agency, 2022b).

These international experiences demonstrate that there is no single approach to managing hydrological uncertainty and electricity procurement costs. Countries adopt regulatory mechanisms that reflect their market structure, institutional capacity, and policy objectives. While competitive electricity markets such as Norway internalize hydrological risks through market pricing, regulated systems such as India and Malaysia rely on periodic tariff adjustment mechanisms, whereas Nepal and Laos primarily use long-term contractual arrangements.

Bhutan differs from these approaches because domestic electricity tariffs continue to be regulated under a cost-plus framework, with procurement cost variations recovered through the Power Purchase Price Adjustment (PPPA) mechanism. Although the PPPA represents an important regulatory tool for cost recovery, its effectiveness in responding to procurement cost variations caused by hydrological uncertainty has not previously been evaluated using historical operational data. This study addresses that gap by examining the relationship between hydrological conditions, power purchase prices, and the effectiveness of Bhutan's quarterly PPPA mechanism.

3. METHODOLOGY

3.1 Research Design

This study adopted a quantitative research design to examine the implications of hydrological uncertainty on power purchase prices during Bhutan's 2022–2025 tariff period. As illustrated in Fig 2 below, the study followed five sequential stages.

First, a comprehensive literature review was conducted to establish the theoretical and policy context relating to hydrological uncertainty, procurement cost recovery and international practices relevant to electricity tariff adjustment mechanisms.

The second stage involved data collection and preparation. Monthly and annual secondary data for the 2022–2025 tariff period were obtained from ERA, BPC, DGPC, the National Energy Policy 2025, Bhutan Energy Data Directory, and other government energy publications. Additional operational data were obtained through institutional access to DGPC, BPC, and ERA. The datasets included actual river inflow, forecast and actual hydropower generation, forecast and actual electricity demand, electricity purchases from domestic hydropower plants such as DGPC, MHP, Puna II and imported electricity.

The third stage involved comparative analysis to examine seasonal and annual variations in river inflow, hydropower generation, electricity demand

and power purchase prices. Actual river inflow was used as an indicator of hydrological uncertainty because Bhutan's predominantly run-of-river hydropower system is directly influenced by seasonal water availability. Comparisons between forecast and actual values were undertaken to identify deviations associated with changes in electricity procurement costs and power purchase prices.

The fourth stage used the Pearson correlation analysis to quantify the relationships among river inflow, hydropower generation, generation variation and PPP. The analysis assessed the relationships and provided statistical evidence of the association between hydrological conditions and power purchase price.

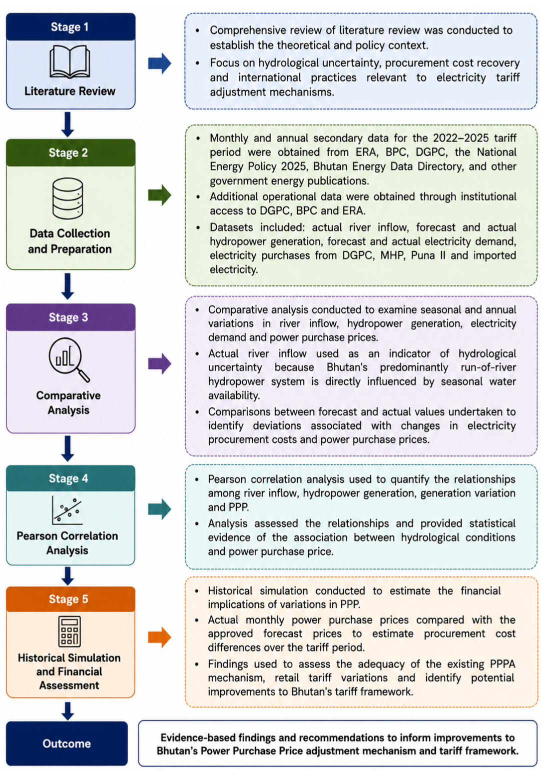

Fig. 2: *Methodology*

Finally, a historical simulation was conducted to estimate the financial implications of variations in PPP. Actual monthly power purchase prices were compared with the approved forecast prices to estimate procurement cost differences over the tariff period. The findings were subsequently used to assess the adequacy of the existing PPPA mechanism, retail tariff variations and identify potential improvements to Bhutan's tariff framework.

3.2 Analytical method

The study uses quantitative comparative analysis, Pearson correlation analysis, historical simulation and tariff variation analysis to evaluate the implications of hydrological uncertainty on PPP.

a. River inflow analysis

Monthly river inflow data were analyzed to see hydrological variability during the study period. River inflow was used as an indicator for hydrological conditions of its direct influence on run-of-river hydropower generation.

b. Generation and demand analysis

Forecasted and actual DGPC generation and demand were compared to quantify deviations during the tariff period using following formulas.

Generation variation:

$$\textit{Generation Variation (\%)} = \frac{\textit{Forecasted Generation} - \textit{Actual Gneration}}{\textit{Forecasted Generation}} \times 100$$

The forecasted generation was used as the baseline because approved tariffs under Bhutan's cost-plus tariff framework are determined using forecasted electricity generation.

Demand Variation:

$$\textit{Demand Variation (\%)} = \frac{\textit{Forecasted Demand} - \textit{Actual Demand}}{\textit{Forecasted Demand}} \times 100$$

c. Power Purchase Price Analysis

The actual power purchase price was calculated using the following formula prescribed under the Tariff Determination Regulation (2025). Actual PPP was then compared with the approved forecast PPP to determine variations resulting from differences between forecast and actual electricity generation and demand

$$\mathrm{PPP} = \frac{\mathrm{AC_{e,g}} \times \mathrm{DOMESTIC_{e,g}} + \sum_i [\mathrm{AC_{n,g}} \times \mathrm{DOMESTIC_{n,g}}]}{\mathrm{DOMESTIC_{e,g}} + \sum_i \mathrm{DOMESTIC_{n,g}}}$$

(i) PPP is the domestic Power Purchase Price (Nu/ kWh);

(ii) ACe,g is the Weighted Average Cost of generation for the existing plants as of 2015 (Nu/kWh);

(iii) ACn,g is the Average Cost for each new generation plant (Nu/kWh);

(iv) DOMESTICe,g is the volume of electricity supplied by the existing DGPC generation plants (GWh); and

(v) DOMESTICn,g is the volume of electricity supplied by each new generation plant (GWh).

d. Pearson Correlation Analysis:

Pearson correlation analysis was performed using Microsoft Excel to examine the relationships among actual river inflow, actual DGPC hydropower generation, DGPC generation variation and PPP. Correlation coefficients (r) and their corresponding p-values were used to assess the statistical significance of the relationships. T

The analysis examined the relationships between:

(i) Actual river inflow and DGPC generation;
(ii) Actual river inflow and PPP;
(iii) Actual DGPC generation and PPP;
(iv) DGPC Generation variation and PPP;
(v) Actual demand and PPP; and
(vi) Demand variation and PPP.

e. Financial implications analysis

The financial implications of variations in PPP were estimated using the following formula:

Financial implications (Nu. Billion) =

$$(Actual\ power\ purchase\ price - Forecasted\ power\ purchase\ price) \times Actual\ energy\ purchased$$

This analysis estimated the additional electricity procurement costs incurred during the tariff period due to differences between forecast and actual PPP. These results were subsequently used to evaluate the effectiveness of the existing quarterly PPPA mechanism in recovering cost variations caused by hydrological uncertainty.

f. Tariff variation analysis

Retail tariff variation was estimated by adding the revised PPP with the approved network charge using the following formula:

Retail Tariff (Nu/kWh) = Increased Power purchase price + Network cost

Retail tariff comprises of PPP and network cost. Network cost is the cost incurred by BPC in transmission and distribution infrastructure and PPP is the weighted average cost of power purchases from various generators.

4. RESULTS AND DISCUSSION

4.1 Hydrological uncertainty and hydropower generation

Bhutan's electricity sector relies predominantly d on run-of-river hydropower, making electricity generation highly sensitive to seasonal river inflows. Understanding the relationship is therefore important for evaluating how hydrological uncertainty affects power purchase price under Bhutan's cost-plus tariff framework.

Fig.3 depicts the monthly variation in actual river inflow and actual DGPC hydropower generation during the 2022–2025 tariff period.

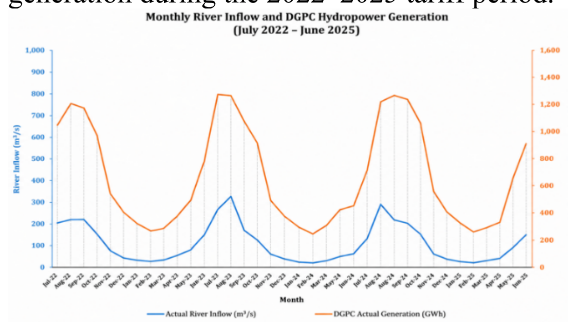

Fig. 3: *River inflow and DGPC generation*

Both variables exhibit a seasonal pattern, with river inflows and electricity generation increasing during the monsoon months and declining during the lean season (November to April). Although river inflow and electricity generation are measured in different units (m^3/s and MU), their temporal trends closely correspond, indicating that higher river inflows are consistently associated with increased hydropower generation.

To quantify this relationship, Pearson correlation analysis was performed. The results show a very strong positive correlation between actual river inflow and actual DGPC hydropower generation ($r = 0.952$, $p < 0.001$), indicating that increases in river inflow are strongly associated with higher hydropower generation. This statistically significant relationship shows that river inflow closely reflects variations in hydropower generation, supporting its use as an indicator of hydrological conditions in Bhutan's run-of river hydropower system.

These findings are consistent with previous studies showing that run-of-river hydropower generation is highly dependent on seasonal river flow variability (Upadhyay et al., 2022, (Yangzom & Choden, 2021). While the correlation shows a strong relationship, it does not prove that hydrological conditions alone cause changes in electricity generation. Other factors, such as scheduled maintenance and transmission constraints, may also affect generation. However, the very strong correlation found in this study suggests that hydrological conditions are the main factor influencing hydropower generation in Bhutan.

The strong relationship between river inflow and hydropower generation provides the basis for examining whether changes in electricity generation subsequently influence power purchase price under Bhutan's cost-plus tariff framework.

4.2 Year-Wise Analysis

Following the analysis of hydrological uncertainty and DGPC hydropower generation, this section examines how variation in DGPC hydropower generation influenced the PPP during the 2022–2025 tariff period**.**

Under Bhutan's cost-plus tariff framework, the approved forecasted PPP for the 2022-2025 tariff period was Nu 1.60/kWh, determined using forecasted electricity generation, electricity demand, and the expected energy supply from various hydropower plants (BPC Tariff Review Report 2022 to 2025, 2022). The forecasted PPP was calculated as the weighted average of energy supplied from DGPC plants at Nu 1.34/kWh (DGPC Tariff Review Report 2022-2025, 2022) and balancing energy purchased from MHP at Nu 3.64/kWh(MHP Tariff Review Report 2022 to 2025, 2022). Based on this forecasted PPP, the current domestic retail tariff for 2022-2025 was set at Nu 2.66/kWh(BPC Tariff Review Report 2022 to 2025, 2022).

Fig. 4 compares the approved forecast PPP with the actual PPP calculated from historical operational data and the resulting financial implications for BPC. The analysis shows that the actual weighted average PPP increased progressively throughout the tariff period.

During 2022-2023 (Year 1), the actual PPP increased marginally by 2% to Nu 1.63/kWh. During the same period, actual DGPC generation decreased by 4%, while electricity demand decreased by 12% relative to the forecast. Although the reduction in demand partly offset the impact of lower generation, the actual retail tariff increased slightly to Nu 2.69/kWh compared with the current tariff of Nu 2.66/kWh.

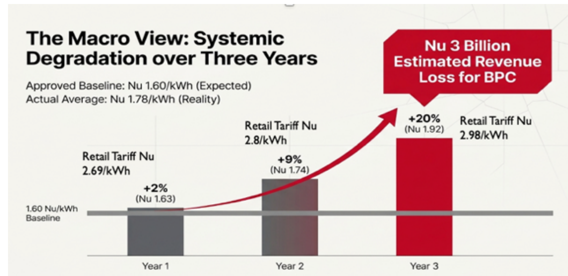

Fig. 4: *PPP Variations and financial implication*

During 2023-2024 (Year 2), the actual PPP increased by 9% to Nu 1.74/kWh. At the same time, actual DGPC generation declined by 6%, while electricity demand increased by 2%. This reduced availability of lower-cost DGPC generation and increased electricity demand required greater purchase of energy from higher-cost generation sources, resulting in an increase in retail tariff from Nu 2.66/kWh to Nu 2.8/kWh.

For 2024–2025 (Year 3), the actual PPP increased significantly by 20% to Nu 1.92/kWh, despite annual DGPC generation increasing slightly by 3%. This suggests that annual averages alone do not adequately explain PPP variations. Although total annual generation increased marginally, significant monthly reductions in lower-cost DGPC generation during the lean season required additional purchase from higher-cost domestic hydropower plants, thereby increasing the weighted average power purchase price. This observation highlights the importance of analyzing monthly operational data rather than relying solely on annual averages, which may overlook seasonal variations in electricity generation and procurement.

Overall, the actual average PPP during the 2022–2025 tariff period was Nu 1.78/kWh, compared with the approved forecasted PPP of Nu 1.60/kWh. The difference of Nu 0.18/kWh, when applied to the actual electricity purchased during the tariff period, resulted in an estimated additional electricity procurement cost of approximately Nu 3 billion. These findings indicate that hydrological variability can significantly increase power purchase price under Bhutan's cost-plus tariff framework.

To complement the comparative analysis, Pearson correlation analysis was carried out using monthly data for the 2022–2025 tariff period to examine the relationships among hydrological conditions (river inflow), hydropower generation, generation variation, demand variation, and power purchase prices as shown in the Table 1 below.

***Table 1**: Pearson correlation analysis*

Variables	Pearson correlation coefficient (r)	P-value
Actual river inflow vs DGPC generation	0.952	<0.001
Actual river inflow vs PPP	-0.73	<0.001
Actual generation vs PPP	-0.81	<0.001
DGPC Generation variation vs PPP	0.365	0.028
Demand variation vs PPP	0.063	0.717
Actual demand Vs PPP	0.262	0.123

The analysis revealed a strong positive and statistically significant relationship between actual river inflow and actual DGPC hydropower generation ($r = 0.952$, $p < 0.001$), confirming that seasonal river inflow is the primary determinant of electricity generation in Bhutan's predominantly run-of-river hydropower system.

River inflow also exhibited a strong negative and statistically significant correlation with Power Purchase Price (PPP) ($r = -0.730$, $p < 0.001$), indicating that lower river inflows were associated with higher power purchase prices.

Similarly, actual DGPC hydropower generation showed a strong negative and highly significant correlation with PPP ($r = -0.81$, $p < 0.001$), indicating that decreases in DGPC hydropower generation were consistently associated with higher power purchase prices.

DGPC generation variation showed a moderate positive and statistically significant relationship with PPP ($r = 0.365$, $p = 0.028$), indicating that larger deviations between forecasted and actual hydropower generation were associated with higher power purchase prices.

In contrast, demand variation exhibited a very weak and statistically insignificant relationship with PPP ($r = 0.063$, $p = 0.717$). similarly, actual electricity demand showed a weak and statistically insignificant relationship with PPP ($r = 0.262$, $p = 0.123$).

Overall, the correlation analysis demonstrates that PPP variations were more strongly associated with hydrological variability affecting domestic hydropower generation than with changes in electricity demand. Although correlation analysis identifies statistical associations rather than direct causality, the consistently stronger relationships between river inflow, hydropower generation and PPP provide strong empirical evidence that hydrological uncertainty was the dominant factor influencing power purchase price during the 2022–2025 tariff period.

4.3 Month-Wise Analysis

Although the year-wise analysis provides an overall assessment of PPP trends during the 2022–2025 tariff period, annual averages do not fully capture the seasonal variations in electricity generation and demand that influence monthly PPP. In Bhutan's predominantly run-of-river hydropower system, electricity generation varies considerably with seasonal river flows, resulting in changes in the electricity procurement mix and monthly PPP. Therefore, a month-wise analysis provides a more comprehensive understanding of the operational factors influencing PPP variations than annual comparisons alone. Fig 5–7 present the monthly comparison of forecasted and actual DGPC generation, electricity demand and PPP during each tariff year.

During the 2022–2023 tariff year, the PPP increased significantly by 33% in May 2023 compared with the forecasted value. This coincided with a 30% reduction in DGPC actual generation, while electricity demand increased by approximately 3% relative to the forecast as shown in Fig.5 below. The reduced availability of lower-cost DGPC generation required additional procurement from higher-cost electricity sources, increasing the weighted average PPP.

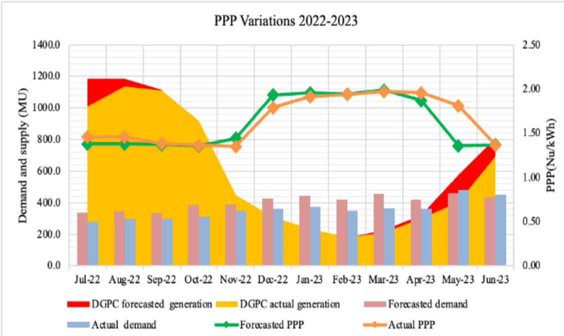

***Fig. 5**: 2022-2023 PPP Variation*

During the 2023–2024 tariff year, PPP increase by 11% in November 2023 due to a 15% reduction in DGPC generation and an 8% rise in electricity demand. In May and June 2024, PPP increased sharply by 64% and 30%, respectively, caused by substantial reductions in DGPC actual generation (40% and 23%) while demand increased by 4% and 5% respectively as shown in Fig. 6 below.

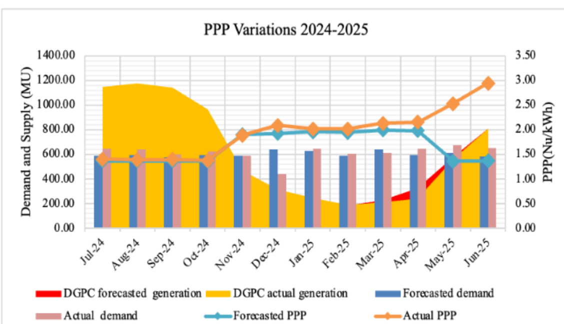

***Fig. 6**: 2023-2024 PPP Variation*

These findings indicate that relatively large reductions in lower-cost hydropower generation during the lean season and the early monsoon months required increased procurement from higher-cost generating stations, thereby increasing the weighted average procurement cost.

During 2024-2025 tariff year, PPP increased sharply by approximately 80% in May 2025 and 100% in June 2025. During this period, DGPC generation decreased marginally by 4% and 1%, while demand increased significantly by 11% and 12% as shown below in Fig. 7 below.

Although the reductions in generation appear relatively small, PPP is determined by the weighted average cost of electricity purchased from all available sources rather than by DGPC generation alone. Monthly procurement records indicate that reduced availability of lower-cost DGPC generation was accompanied by increased procurement from higher-cost domestic hydropower plants, particularly MHP, Puna-II and imported electricity. Consequently, even relatively small reductions in lower-cost generation can substantially increase the weighted average PPP when the electricity procurement mix changes.

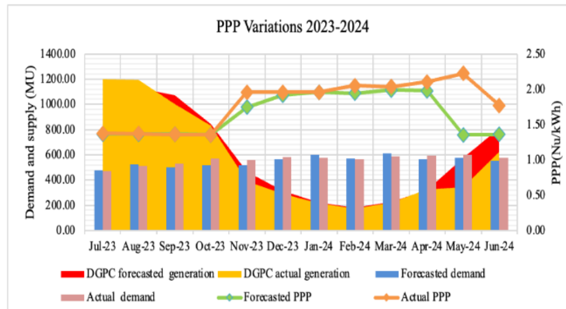

***Fig. 7**: 2024-2025 PPP Variation*

This explains the apparent discrepancy observed in the year-wise analysis, where PPP increased despite a small increase in DGPC generation. The monthly analysis shows that annual averages can overlook the seasonal fluctuations in electricity generation and procurement costs, particularly during the lean season and early monsoon months.

The month-wise observations are consistent with the Pearson correlation analysis presented in Section 4.2, which showed that PPP was more strongly associated with river inflow and hydropower generation than with electricity demand. Together, these findings indicate that hydrological variability affecting the availability of lower-cost hydropower generation was more strongly associated with power purchase price variations than changes in electricity demand.

Although other operational factors, such as planned maintenance, transmission constraints, and system dispatch decisions, may also influence electricity procurement, the results suggest that hydrological conditions were the dominant factor affecting PPP during the study period.

Overall, the month-wise analysis demonstrates that seasonal variations in hydropower generation and the resulting changes in the electricity procurement mix have a much greater influence on

PPP than is evident from annual averages alone. These findings provide strong empirical support for adopting a more responsive cost recovery mechanism that better reflects actual monthly costs under changing hydrological conditions.

4.4 Historical Simulation of Monthly Power Purchase Price Adjustment

To assess the financial implications of hydrological uncertainty, a historical simulation was carried out by comparing the forecasted PPP approved during tariff determination with the actual PPP calculated using monthly operational data. The difference between the forecasted and actual PPP was multiplied by the corresponding actual electricity purchased to estimate the additional electricity procurement cost incurred by BPC throughout the 2022–2025 tariff period.

The simulation showed that actual procurement costs consistently exceeded the forecasted values throughout the study period, reflecting the progressive increase in PPP identified in the year-wise and month-wise analyses. The cumulative additional electricity procurement cost was estimated at approximately Nu. 3 billion as shown in Table 2 below, indicating that BPC incurred substantially higher procurement costs than anticipated during tariff determination.

Table 2: *Quarterly procurement cost differences estimated through historical simulation under the existing quarterly PPPA mechanism (Nu million)*

Tariff Year	Q1 (July-Sept)	Q2 (Oct-Dec)	Q3 (Jan-March)	Q4(April-June)	Annual Total
2022–2023	157.08	101.90	(288.61)	(143.38)	(173.01)
2023–2024	371.99	(144.42)	(345.89)	(692.16)	(810.48)
2024–2025	398.13	(246.36)	(407.76)	(1,742.13)	(1,998.1)
Total	**927.20**	**(288.87)**	**(1,042.26)**	**(2,577.67)**	**(2,981.60)**

**Note: Positive values indicate procurement cost savings (actual procurement cost was lower than the forecast), whereas values in parentheses indicate additional procurement costs (actual procurement cost exceeded the forecast).*

The procurement cost differences were highly seasonal. Procurement cost savings were primarily observed during the peak monsoon period (July–September), when abundant river inflows increased lower-cost hydropower generation and reduced the need for procurement from higher cost electricity sources. Conversely, procurement cost differences accumulated during the subsequent lean season and early monsoon months, particularly between January and June, when reduced availability of lower-cost hydropower generation required greater procurement from relatively higher-cost electricity sources. This pattern is consistent with the month-wise analysis, which showed May and June as the months with the largest increases in PPP, showing that seasonal changes in hydropower availability have a direct impact on PPP.

Under Bhutan's existing tariff framework, these procurement cost differences are recovered through the quarterly PPPA mechanism. While the quarterly adjustment allows procurement costs to be recovered over time, the historical simulation suggests that significant procurement cost differences may accumulate before they are reflected in retail tariffs. This creates a temporary mismatch between actual procurement costs incurred by BPC and the timing of cost recovery, potentially affecting cash flow and increasing financial exposure during periods of prolonged hydrological variability.

The findings suggest that the current PPPA is an effective cost recovery mechanism but may not fully reflect the timing of procurement cost variations caused by seasonal hydrological fluctuations. Since procurement costs fluctuate considerably throughout the year, particularly during the lean season, more frequent adjustments could improve the timeliness of cost recovery while maintaining the principles of Bhutan's cost-plus tariff framework.

These findings are consistent with the international experiences discussed in the literature review. Although regulatory approaches differ across countries, countries such as India and Malaysia use periodic fuel or power purchase cost adjustment mechanisms to recover actual costs more frequently, thereby reducing the accumulation of unrecovered costs. In contrast, Norway, Nepal, Laos, and Tajikistan primarily manage hydrological variability through market-based pricing and long-term contractual arrangements. Although Bhutan's regulatory framework differs from these approaches, the historical simulation suggests that improving the responsiveness of the PPPA mechanism could strengthen procurement cost recovery under increasing hydrological uncertainty.

Overall, the historical simulation shows that hydrological uncertainty has significant financial implications for electricity procurement under Bhutan's cost-plus tariff framework. While the existing quarterly PPPA enables eventual recovery of procurement cost differences, improving the frequency or responsiveness of the adjustment mechanism could better align the cost recovery with actual monthly procurement costs and enhance the financial sustainability of the electricity sector.

5. RECOMMENDATIONS

The findings of this study indicate that hydrological uncertainty significantly influences power purchase price under Bhutan's cost-plus tariff framework. The comparative analysis showed that actual PPP increased progressively above forecasted values during the 2022–2025 tariff period, while the Pearson correlation analysis demonstrated that power purchase price variations were more strongly associated with hydrological variability affecting domestic hydropower generation than with changes in electricity demand. The historical simulation further showed that power purchase cost differences accumulated under the existing quarterly PPPA mechanism before being recovered through tariff adjustments. Based on these findings, the following policy recommendations are proposed.

5.1 Review the frequency of Power purchase price adjustment (PPPA)

The historical simulation presented in Section 4.4 showed that procurement cost differences accumulated under the existing quarterly PPPA mechanism, resulting in an estimated additional electricity procurement cost of approximately Nu 3 billion over the 2022–2025 tariff period. Although introducing a monthly PPPA would not reduce the overall procurement cost, it could improve the timeliness of cost recovery by reducing the accumulation of procurement cost differences between adjustment periods.

Based on these findings, this study recommends that the ERA evaluate the feasibility of introducing a monthly PPPA mechanism under the Tariff Determination Regulation (2025). A monthly adjustment would enable retail tariffs to respond more promptly to actual monthly power purchase price, improve tariff transparency, improve cash-flow management of BPC, and reduce the delay in recovering legitimate power purchase cost.

To balance financial sustainability with consumer protection, a regulatory adjustment cap (for example, ±5%) could also be considered, whereby relatively small procurement cost variations are absorbed by BPC while larger deviations are passed through in accordance with the approved regulatory framework. Such an approach would help maintain tariff stability and affordability while ensuring timely recovery of procurement costs.

5.2 Evaluate a differentiated power purchase price structure

The month-wise analysis showed that increases in PPP were primarily associated with periods when additional electricity was procured from higher-cost hydropower plants during the lean season and early monsoon season. These higher procurement costs are currently reflected through a consolidated PPP applied across all consumer categories, despite differences in consumption patterns and procurement requirements.

Based on these findings, this study recommends that the ERA evaluate the feasibility of introducing a differentiated PPP structure. Under this framework, residential and small business consumers, whose electricity demand can generally be met by lower-cost DGPC hydropower generation throughout most of the year as shown in the Fig 8 below, could continue to receive a relatively stable DGPC-based tariff. In contrast, heavy industrial consumers, whose demand contributes more significantly to higher-cost power purchase during peak and lean-season periods, could be subject to a more dynamic PPP that reflects actual procurement costs.

A differentiated PPP structure could improve transparency in cost allocation, enhance equity among consumer categories, and support the financial sustainability of the BPC while maintaining affordability for residential consumers.

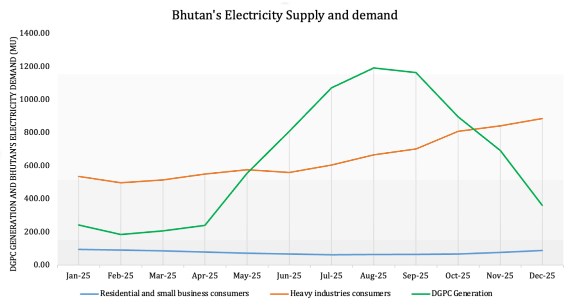

***Fig. 8**: Bhutan's Electricity demand and supply*

5.3 Promote Solar PV adoption

The study found that power purchase price increased significantly during periods of reduced hydropower generation associated with seasonal hydrological variability. These findings highlight the importance of diversifying Bhutan's electricity supply to reduce dependence on seasonal hydropower generation.

The continued development of solar photovoltaic (PV) systems may complement hydropower generation during periods of hydrological constraint. Tariff review reports for the 22.38 MWp Sephu Solar Project and the 200 kW Ground-Mounted Solar Project at Tamzhing indicate levelised generation costs of approximately Nu 3–4/kWh (Tariff Review Report of 200 KW Ground-Mounted Solar Project at Tamzhing, Bumthang, 2025)& (Tariff Review Report of 22.38 MWp Sephu Solar Project, 2025). During the lean season, the effective PPP applicable to heavy industrial consumers, which includes procurement from higher-cost domestic hydropower plants and imported electricity, can increase to approximately Nu 5–6/kWh, as shown in Fig 9 below. Since the levelized cost of solar PV is lower than this seasonal procurement cost, expanding solar PV could reduce reliance on higher-cost electricity procurement during periods of hydrological constraint while improving the resilience and financial sustainability of Bhutan's electricity sector.

Nevertheless, further techno-economic, financial and grid integration studies are required to determine the optimal scale and economic feasibility of wider solar PV deployment.

5.4 Exploring long-term electricity market reforms (Introducing power market)

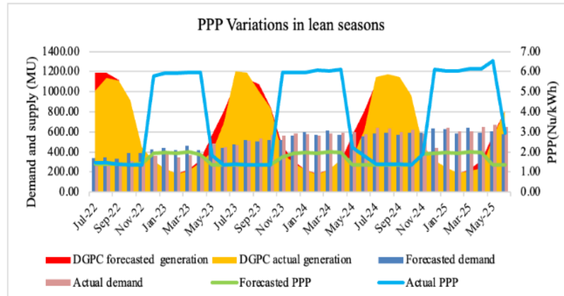

***Fig. 9**: PPP applicable to heavy industries during lean seasons*

The findings of this study indicate that power purchase price variations were driven by changes in the electricity energy purchase mix under the existing cost-plus tariff framework. As Bhutan's electricity sector evolves, additional regulatory mechanisms may be required to improve procurement flexibility and tariff transparency.

Consistent with the Domestic Tariff Projection 2040 report, Bhutan could gradually develop a more competitive electricity market and introduce long-term Power Purchase Agreements (PPAs) between domestic electricity generators and large electricity consumers (Domestic-Tariff-Projection-2040, 2022). Under a competitive power market, electricity prices would be determined through market mechanisms and passed directly to consumers, reducing the need for periodic power purchase price adjustments under the existing cost-plus regulatory framework. This approach is also consistent with the international practices discussed in the literature review. Long-term PPAs could provide greater price certainty for both generators and consumers, improve procurement planning, and reduce exposure to short-term fluctuations in power purchase price arising from seasonal hydrological variability. Together, these market-based reforms could enhance tariff transparency, improve financial sustainability, and strengthen the long-term resilience of Bhutan's electricity sector. However, the present study did not assess the economic feasibility, contractual arrangements or institutional requirements associated with competitive electricity markets or long-term PPAs. Consequently, these policy options should be regarded as areas for future regulatory investigation rather than immediate implementation measures.

6. CONCLUSION

This study examined the implications of hydrological uncertainty for power purchase price under Bhutan's cost-plus electricity tariff framework during the 2022–2025 tariff period. By integrating comparative analysis, Pearson correlation analysis and a historical simulation of PPPA mechanism, the study examined how seasonal variations in river inflow influenced hydropower generation, PPP and the cost recovery.

The findings showed that hydrological variability was the primary factor associated with changes in power purchase price during the study period. River inflow showed a very strong positive relationship with actual hydropower generation, confirming that Bhutan's predominantly run-of-river hydropower system is highly sensitive to seasonal hydrological conditions. The analysis further showed that reductions in lower-cost DGPC hydropower generation were closely associated with increases in PPP, while electricity demand had only a weak and statistically insignificant relationship with power price. The month-wise analysis also demonstrated that annual averages does not capture substantial seasonal variations, particularly during the lean season when changes in the power procurement mix resulted in significant increases in monthly PPP.

The historical simulation estimated an additional electricity procurement cost of approximately of Nu. 3 billion, indicating that the cost differences accumulated under the existing quarterly PPPA mechanism before being recovered through tariff adjustments. Although the current PPPA facilitates cost recovery within Bhutan's cost-plus tariff framework, the findings suggest that the timing of procurement cost recovery may not fully reflect the seasonal nature of procurement cost variations associated with hydrological uncertainty.

This study contributes to the literature by providing one of the first empirical assessments of the relationship between hydrological uncertainty, hydropower generation and power purchase price within Bhutan's regulated electricity sector. The findings provide empirical evidence that can support future regulatory reviews of procurement cost recovery mechanisms in hydropower-dependent electricity systems.

The study should, however, be interpreted within the context of several limitations. The analysis was based on historical operational data for the 2022–2025 tariff period and employed comparative and correlation analysis, which identify statistical associations but do not establish direct causal relationships. In addition, other operational factors, including maintenance schedules, transmission constraints, contractual dispatch arrangements and electricity trading decisions, were not explicitly examined and may also influence procurement costs.

Further studies may also assess the economic feasibility and regulatory implications introducing power market, differentiated pricing mechanisms and increased integration of complementary renewable energy sources within Bhutan's evolving electricity sector.

7. ACKNOWLEDGEMENT

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