Case Study

Flexibility Potential in the Nepalese Power System: A Diagnostic Analysis

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Abstract

Nepal's power system, dominated by run-of-river hydropower, faces a critical seasonal flexibility challenge, characterized by significant energy surpluses in the wet season and severe power deficits in the dry season. This study conducts a comprehensive flexibility assessment of the Integrated Nepal Power System (INPS) to quantify these operational gaps and evaluate the role of storage hydropower as a mitigating solution. Using the FlexTool, a power balance simulation was performed on a single-node model of the INPS. The analysis reveals that in the 2025 base case, the system fails to serve 5.68% of the annual demand while simultaneously curtailing a massive 5.22 TWh of variable renewable energy (VRE). A sensitivity analysis demonstrates that increasing the share of storage hydropower is highly effective; a generation mix with 35% storage capacity virtually eliminates loss of load and reduces VRE curtailment by 76%. Future scenarios for 2030 indicate that achieving national capacity targets is crucial, but even then, a storage share of 20-30% will be required to maintain reliability under high-growth and policy-driven demand scenarios. The findings underscore the need for a capacity expansion planning with strategic investment in seasonal storage to ensure flexibility and efficient use of renewable resources in Nepal's power system.

Categories: Renewable Energy Systems

Keywords: flexibility, flextool, hydropower plants, loss of load, nepalese power system, storage hydropower, variable renewable energy, vre curtailment

Introduction

Decarbonizing the energy sector results in a global shift toward renewable energy sources (RESs) by setting targets to increase renewable energy generation (e.g.: wind, solar, and others). However, the deployment of large shares of RESs comes with a set of challenges for power system operation and control. The generation from RESs is strongly dependent on weather conditions, which are highly unpredictable and volatile. Variable renewable energy (VRE) contributes to the greater variability and uncertainty of the supply in power system operation [1]. It significantly impacts the reliability and power quality and does not provide inertia support, making the grid vulnerable during faulty conditions [2]. Large shares of VRE, along with variability in electricity demand, present a challenge of demand-supply balance along with grid congestion for the power system operator. If not properly planned, this could affect the reliability of the power system. In this context, an increase in flexibility is necessary to mitigate potential mismatches in supply and demand induced by these changes. Power system flexibility, a characteristic of all power systems, is the ability of a power system to respond to changes in demand and supply [3].

Power system flexibility is defined as the ability of a power system to respond to expected and unexpected changes in demand and supply [4]. It is the ability to manage the variability and uncertainty in the supply-demand balance reliably and cost-effectively [5]. Power system flexibility has been a significant research topic due to the increasing integration of RES and the need to ensure a stable and reliable power supply. These studies focused on the power and energy balance issues faced by power systems under transition due to the unpredictability, volatility, and reverse peak shaving features of solar and wind power generation output, and several metrics were used to quantify power system flexibility. Table *1* presents highlights from recent studies focused on power system flexibility, along with several metrics and indices used to evaluate the system's flexibility and strategies for improving it.

Ref	Publi-shed Year	Objectives	Methodology	Findings
[6]	2025	Flexibility optimization	Hierarchical programming, Optimal power flow	The paper optimized the maximal range of uncertainty for manageable power transfer between two parts of a network using DC flow approximation. The study was performed on a small-scale model IEEE 30-bus system and a medium-scale model of the power transmission grid between France and Spain, where uncertainties in one region, for example, Spain, were handled by power transfer from another region, i.e. France. The numerical experiments on a medium-sized grid instance were shown to be solvable in reasonable computation times.
[7]	2024	Propose new flexibility metric and quantify flexibility	Stochastic assessment, Linear Programming (LP) optimization model in real-time economic dispatch problem.	Considering the stochastic nature of net load, the paper introduced the hyperbox metric, which is formulated into a distributionally robust optimization framework that assesses system flexibility accommodating a minimal extent of system violations. In comparison to previous conventional deterministic flexibility assessments, the suggested approach consistently produced

				less conservative flexibility outcomes when the flexibility of the real-time economic dispatch problem was solved on four IEEE standard test systems.
[8]	2024	Cost-benefit analysis for flexibility in hydrothermal system	Deterministic linear programming for optimization of cost of electricity	The paper proposed a net cost of flexibility as a flexibility metric which was used to rank different flexibility sources in systems with large amounts of renewable energy. Brazil 2031 system was taken as a case study which was modeled in Plexos, an energy modeling software, where different types of technologies were evaluated as potential candidates for flexibility expansion. The same flexible asset has been found to be able to provide medium-term flexibility (hydro balance during dry seasons) as well as short-term flexibility (peaking during ramps caused by variable renewables).
[9]	2024	Flexibility enhancement with high share of renewables	Simulation, FlexTool	The paper analyzed the flexibility of Algeria's power system using FlexTool. Loss of load and curtailment of variable renewable energy were used as the flexibility indices. The flexibility analysis was performed to determine the optimum size and placement of gas power plants and

				renewables for the year 2030.
[10]	2023	Flexibility resource planning	Bi-level optimization problem	The paper proposed a probability index of an insufficiently flexible supply–demand ratio based on the probability characteristics of flexibility and developed a bi-level programming model consisting of a planning layer model and an operations layer model. The proposed index can effectively quantify the power system flexibility under uncertainty and can be used in optimal planning of cost and expected flexibility in the system.
[11]	2024	Evaluate flexibility potential of decentralized energy systems	Optimal energy management model	The paper investigated the flexibility potential of PV-battery storage systems and heat pump-heat system, which are dependent on their modes of operation, storage capacity, and planned operation. Aggregation of such systems and grid-oriented operation significantly contributes to flexibility balancing energy-surplus and deficits.
[12]	2024	GTEP model for the electricity market with decarbonization policies	Tri-level model, quadratic programming optimization problem	The paper implemented the market-driven generation and transmission expansion model in Southern China electricity market as case study in different decarbonization policy

				scenarios. The study concluded that a purely market-driven approach without decarbonization policies could not realize carbon peaking for Southern China electricity market and a combination of carbon emission allowance and carbon tax can be optimized to achieve the defined target. This methodology can be implemented in other countries as well.
[13]	2024	GEP with increasing VRE	optimization with economic dispatch, OptGen, SDDP and OnSSET tools	The paper combined the long-term generation capacity expansion plan with economic load dispatch and applied to West African Power Pool. The paper highlighted that the 10% VRE limit set in the WAPP Master Plan is sub-optimal and the VRE can supply up to 40.9% of the annual peak demand in some countries. The paper emphasized that the increment in VRE supplemented by improvement in infrastructure could enhance both energy security and sustainability.
[14]	2025	Quantify the hydropower flexibility and optimize the flexibility to increase wind power penetration	probabilistic reliability assessment, Argonne Low-carbon Electricity Analysis Framework (A-LEAF)	The paper used the capacity expansion model in A-LEAF to examine how varying levels of hydropower operational flexibility impact least-cost capacity expansion. A flexibility index,

				indicating the hourly dispatch capability of hydropower, was introduced to quantify and control hydropower's ability to provide operational flexibility. A case study on the Pacific Northwest and California was conducted, to evaluate the impact on wind, natural gas, and storage capacity in the optimal generation mix. The paper emphasized that higher hydropower flexibility leads to more wind generation investment and less natural gas and battery storage investment resulting in lower system cost, lower emission and increment in operating profits due to the ability to shift generation to higher-priced periods. The effective load-carrying capability (ELCC) of both hydropower and wind improves with more hydropower flexibility.
[15]	2024	Quantify power system flexibility of Colombia for energy transition	Statistical Estimation and Analysis	This paper used net load and ramping of net load as indices to evaluate flexibility in Colombian power system. The authors compared the net load ramps with the flexibility potential of hydro and thermal generation to determine if high levels of renewable energy could put the system at

				risk. The system faced challenges to maintain flexibility during low hydrology periods.
[16]	2024	Developing a new flexibility-oriented model for GEP of renewable-based energy systems	MILP, unit commitment	The paper utilized a flexibility deficiency metric to develop GEP model of national power system of Iran with a twenty-year planning horizon. The study highlighted the importance of integrating the flexibility metric (EFD) into power system expansion planning to optimize capacity and generation mixes while avoiding sub-optimal solutions, resulting in a 68% to 87% violation cost reduction under various scenarios and only a 9.43% increase in planning costs due to an increase in renewables portfolio.

TABLE 1: Summary of different flexibility assessment methods in power system

PV, Photovoltaic; VRE, variable renewable energy

The recent literature reveals a strong emphasis on quantitative techniques to analyze power system flexibility. The choice and use of quantitative flexibility metrics, however, vary across different research subjects and fields. To diagnose flexibility issues in a power system, it is therefore important, first, to develop robust metrics for flexibility and, second, to use these metrics to guide future infrastructure investments.

A flexible system can schedule internal resources to respond to net load changes. While this challenge is universal, its manifestation is unique in every power system. For a nation like Nepal, with its distinct hydro-dominated generation profile, understanding and quantifying flexibility are fundamental to its energy security and economic future. The literature provides a rich set of methodologies for power system flexibility analysis, particularly for grids integrating high shares of VRE. Studies on hydro-dominated systems offer valuable insights into managing seasonal variability. However, there has not been a study that applied these established flexibility assessment frameworks to quantify the specific challenges and opportunities within the Nepalese power system. This research aims to fill this gap and conduct a flexibility assessment of the Nepalese power system. The contribution of the paper is identifying and quantifying flexibility issues due to seasonal hydro-variability and short-term solar variability.

Case Presentation

Overview of Nepalese power system

Figure 1 shows the location of existing and under-construction hydropower and solar photovoltaic (PV) plants on the map of Nepal. The country has significant hydropower potential and had a total installed capacity of 3152 MW by 2025, dominated by hydropower plants [17].

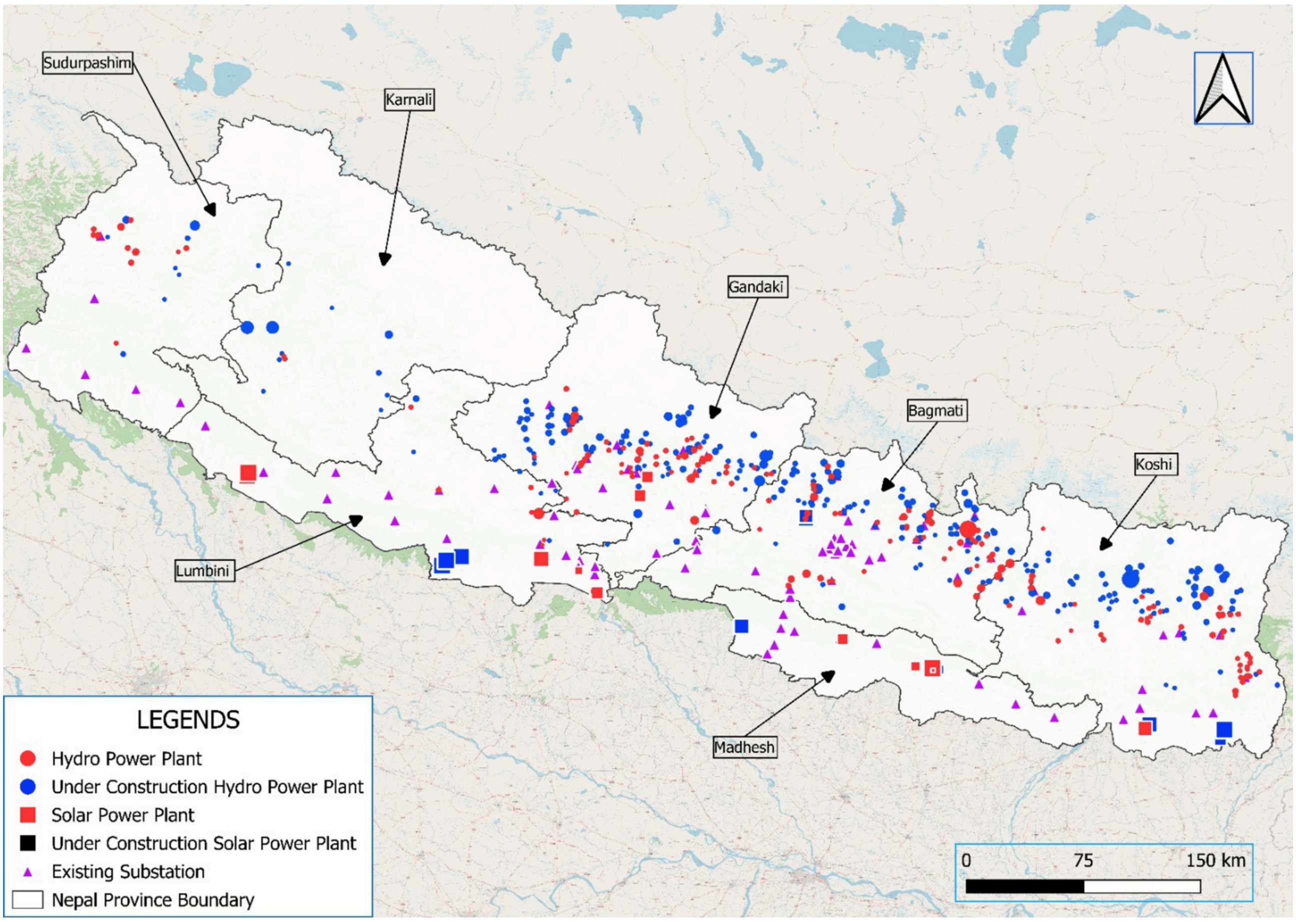

FIGURE 1: Map of Nepal showing existing and under-construction power plants

Figure 2 illustrates the existing generation mix, primarily comprising with hydropower plants, run-of-river (RoR), with small contributions from solar, thermal, and cogeneration plants. RoR hydropower accounts for 66.3% of the capacity, followed by peaking run-of-river (PRoR) hydropower at 25%. Storage hydropower and solar PV plants each constitute 3.4%. The thermal power plants constitute 1.7% and the cogeneration plants using bagasse constitute 0.2%. As of 2025, the installed capacity includes 2986 MW of hydropower plants (2090 MW RoR, 790 MW PRoR, and 106 MW storage), 107 MW of solar power plants, 53 MW of thermal power plants, and 6 MW of cogeneration power plants [18].

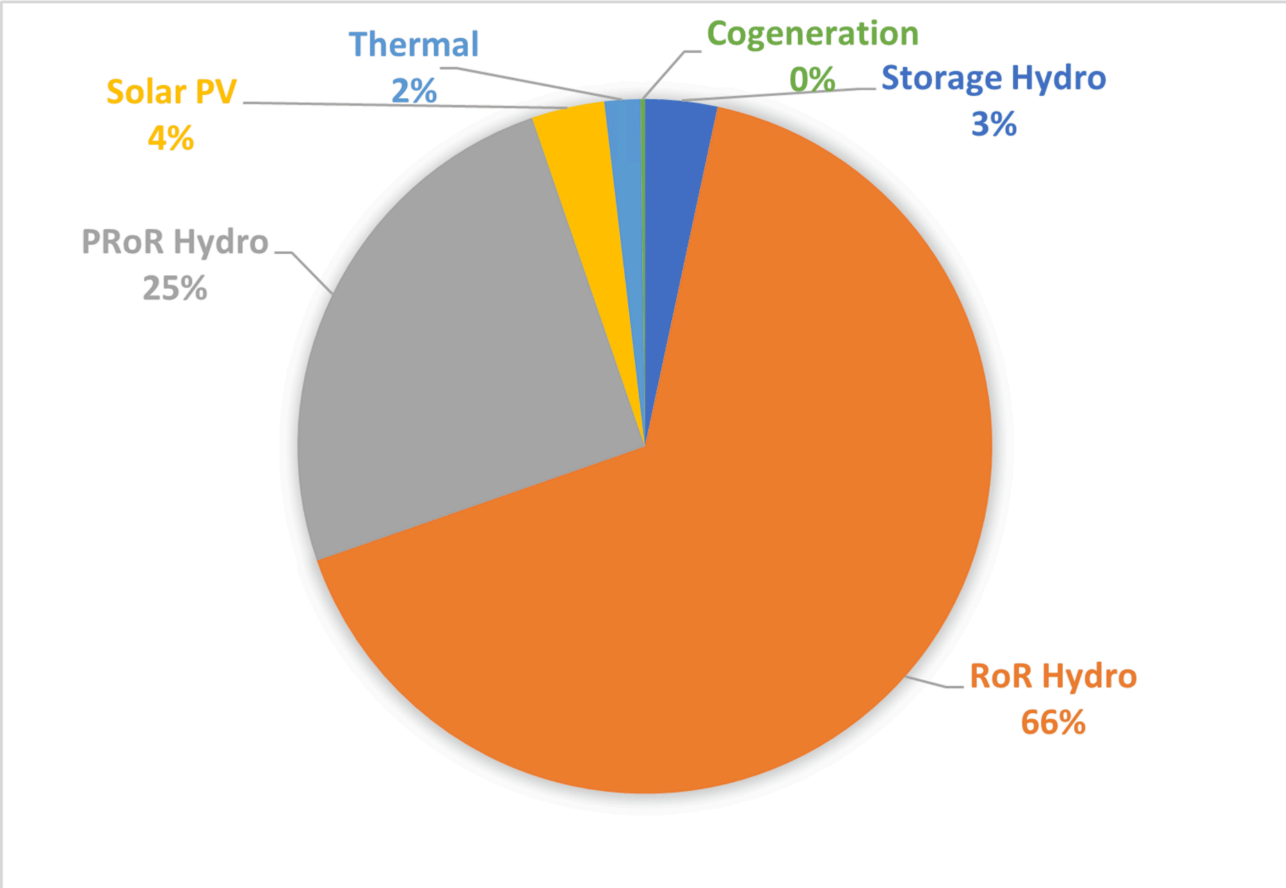

FIGURE 2: Existing generation mix of Nepal

PV, Photovoltaic; RoR, run-of-river; PRoR, peaking run-of-river

The dominance of RoR hydropower projects in Nepal has resulted in significant seasonal generation-demand imbalances. Hydropower generation is highly dependent on river hydrology, which peaks during the monsoon season and declines in the dry months [19]. As a result, the system experiences substantial surplus energy during the wet season and acute supply deficits during winter and dry periods. In addition, solar PV generation is weather-dependent, further contributing to variability. The overreliance on RoR projects exacerbates this imbalance, leading to energy spillage during high-flow periods and increased electricity imports from India during low-flow seasons to meet demand and avoid power shortages [20].

In response to these challenges, the Government of Nepal has outlined ambitious energy targets and policy directions. The 2018 White Paper sets a goal of reaching 15,000 MW of installed capacity within a decade [21]. It also proposes a generation mix with the ratio of reservoir and pumped storage as 30-35%, PRoR as 25-30%, RoR as 30-35%, and other alternative sources as 5-10%. The mix was later modified by the Cabinet decision on July 8, 2022, which adjusted the ratio to 20-25% for reservoir-based, 25-30% for PRoR, 40-45% for RoR, and 5-10% for other alternative sources [22]. Furthermore, under its Nationally Determined Contribution (NDC), Nepal aims to generate 5-10% of its total electricity from renewables, primarily from grid-connected solar PV plants [23].

On the demand side, the country is undergoing rapid urbanization, and national grid expansion is expected to be completed within the next two years [20]. At the same time, Nepal's economic development strategy is increasingly focused on industrialization, while NDC commitments are to accelerate the adoption of electric cooking and electric vehicles (EVs) [23]. These developments are expected to significantly increase electricity demand. In this evolving context, the seasonal mismatch between generation and load is likely to intensify, posing operational and planning challenges.

Ongoing policy shifts in the generation mix, along with the integration of VRE sources introduce additional uncertainty into the system. This makes the assessment of system flexibility increasingly important. Without proper planning and analytical tools, these changes could lead to inefficiencies, increased curtailment, and reliability concerns.

Therefore, a comprehensive assessment of power system flexibility is essential to support planning decisions, ensure grid reliability, optimize renewable energy utilization, and guide cost-effective investments in storage and flexible resources. This study aims to address this need by conducting a diagnostic analysis of Nepal's power system flexibility under both current and future scenarios. It evaluates existing flexibility based on annual load profiles and hydrological variability, and further examines system performance under different generation and demand scenarios.

Diagnostic framework for flexibility assessment

This study employs a systematic diagnostic framework to assess the operational flexibility of the Nepalese power system, officially called the Integrated Nepal Power System (INPS). The methodology is based on a chronological time-series power balance simulation using the IRENA FlexTool, which allows for a detailed analysis of the system's ability to meet demand under varying generation and load conditions. IRENA FlexTool was selected for its suitability in conducting diagnostic assessments of power system flexibility. The FlexTool is a power system simulation model that performs an economic dispatch as an optimization problem for a full year (8760 hours), where available generation sources are dispatched to meet the hourly load. This approach is highly effective for identifying periods of energy surplus (leading to curtailment or spillage) and energy deficit (leading to loss of load), which are the core indicators of system flexibility challenges [24].

The mathematical formulation of the optimization problem is shown below. The symbols used in the equation are defined in Table *2*.

Objective function

$$Z = \sum_{t \in T} \left(C_t^{\text{om}} + C_t^{\text{penalties}} \right) h + C^{\text{investment}}$$

Operation and maintenance cost

$$C_t^{\text{om}} = \sum_{u \in U} p_u^{\text{om}} \cdot E_{u,t}^{\text{gen}}$$

Penalty cost

$$C_t^{\text{penalties}} = LoL_t \cdot p^{\text{lossofload}} + Cur_t \cdot p^{\text{curtailment}}$$

Investment cost

$$C^{\text{investment}} = \sum_{(g,n,u) \in U} p_u^{\text{investment}} \cdot v_{g,n,u}^{\text{investedCapacity}}$$

Energy balance constraint

$$G_t + I_t - E_t + LoL_t = D_t$$

Curtailment constraint

$$Cur_t \leq \sum_{u \in U^{\text{VRE}}} cf_{u,t} \cdot Cap_u$$

Nomenclature

Symbol	Description	Unit
$t \in T$	Time index	–
T	Set of all time periods (8760 hours)	–
$u \in U$	Generation unit index	–
U	Set of all generation units	–
U^{VRE}	Set of variable renewable energy units	–
(g,n,u)	Generator-node-unit index combination	–
$E^{gen}_{u,t}$	Energy generated by unit (u) at time (t)	MWh
LoL_t	Loss of load at time (t)	MWh
Cur_t	Curtailed energy at time (t)	MWh
$v_{g,n,u}^{investedCapacity}$	Invested (installed) capacity of unit (u)	MW
p_u^{om}	Operation and maintenance cost of unit (u)	Cost/MWh
$p^{lossofload}$	Penalty cost of loss of load	Cost/MWh
$p^{curtailment}$	Penalty cost of curtailment	Cost/MWh
$p_u^{investment}$	Investment cost of unit (u)	Cost/MW
$cf_{u,t}$	Capacity factor of unit (u) at time (t)	–
Cap_u	Installed capacity of unit (u)	MW
h	Duration of each time step	hours
C_t^{om}	Operation and maintenance cost at time (t)	Cost
$C_t^{penalties}$	Total penalty cost at time (t)	Cost
$C^{investment}$	Total investment cost	Cost
G_t	Total generation at time (t)	MWh

I_t	Imports at time (t)	MWh
E_t	Exports at time (t)	MWh
D_t	Demand at time (t)	MWh
Z	Total system cost (objective function)	Cost

TABLE 2: Nomenclature

System modeling and assumptions

To create a tractable and focused analysis, the following assumptions were adopted while modeling the INPS.

Single-Node Model

The INPS is modeled as a single electrical node abstracting away from internal transmission constraints. This approach is standard for initial national-level flexibility studies where the primary concern is resource adequacy and temporal energy balancing.

System Isolation and Cross-border Interconnection

The main diagnostic analysis models the INPS as an isolated system to assess the inherent domestic flexibility of Nepal's generation portfolio. This assumption is important because Nepal is interconnected with the Indian power system, and unrestricted import/export could mask domestic flexibility gaps by allowing the neighboring system to act as an external source during deficit periods and as a sink during surplus periods. However, in response to the practical role of cross-border electricity trade (CBET), an additional import/export case is included for the base year. The import/export case is used only for the base-year diagnostic comparison to demonstrate how interconnection improves operational flexibility. The future scenarios are analyzed without cross-border exchange in order to evaluate whether Nepal's planned domestic generation expansion is sufficient to meet future demand under different growth and policy-driven electrification pathways.

Generation Mix

The model includes RoR hydropower, PRoR hydropower, storage hydropower, and solar PV. Around 2.2% of the diesel power plant and cogeneration plant (bagasse plant) have been omitted from the study as these are not considered for future expansion. Furthermore, diesel power plants are utilized less, and bagasse plants are developed by sugar mills for internal use, and they supply to the grid only during surplus times. Hence, the study has omitted those plants from the study. Furthermore, the study does not consider operational reserves and capacity margin for planning.

Future Demand Profile

The demand profile for 2030 has been assumed to be the same as the existing profile, with peak demand.

Scenario development

To comprehensively diagnose the flexibility of the INPS, a multi-scenario approach was designed to assess the system's performance under current conditions, hypothetical changes, and future policy-driven plans.

Scenario 1: Base Case (2025 System): This scenario models the current INPS with the existing generation mix and load profile of 2025. Three variants are analyzed:

1. Base case with PRoR modeled as RoR: This represents a simplified modeling approach, where existing PRoR hydropower capacity is aggregated with RoR hydropower and treated as a non-dispatchable resource. This case serves as a reference to evaluate the extent to which neglecting the short-term storage capability of PRoR hydropower affects the assessment of seasonal flexibility requirements.

2. Base case actual: In the actual base case, PRoR plants are modeled separately with their limited pondage capacity. Comparing this case with the simplified representation will help assess the contribution of PRoR plants to the operational flexibility of the system.

3. Base case with import/export: This case includes CBET using the available interconnection capacity and existing trade arrangements as a reference. It is used to evaluate the impact of imports during deficit periods and export during surplus periods on loss of load, curtailment, and overall flexibility. Three different trade scenarios are considered.

These three base-case variants help to establish a baseline for flexibility performance of INPS and help quantify the operational challenges associated with seasonal power deficits and surpluses.

Scenario 2: Generation Mix Sensitivity: To explicitly demonstrate the value of dispatchable generation, this scenario analyzes the 2025 system under hypothetical variations of storage hydropower in the system. The analysis focuses on how changes in the generation portfolio, particularly the ratio between RoR and storage hydropower, the system's ability to manage variability and improve flexibility.

Scenario 3: Future Outlook (2030): This scenario assesses the flexibility of the INPS in the year 2030 based on official government plans and targets. It combines the 2030 load forecast with different potential generation expansion pathways. Two total generation capacity scenarios were modeled with varying generation mix scenarios. First, 8937 MW: the capacity requirement from Water and Energy Commission Secretariat (WECS) study [25] and secondly, 11769 MW: the installed capacity target of 16th plan [26].

For both capacity targets, solar PV capacity was fixed at 10% in accordance with the NDC target [23]. The remaining capacity was allocated to RoR, PRoR, and storage hydropower. Two generation mix cases were considered by fixing the PRoR share at 10% and 25%, respectively. Within each case, the share of storage hydropower was varied from 10% to 35%, while the remaining capacity was allocated to RoR hydropower. In total, 24 generation mix scenarios were developed.

Load forecast scenarios from WECS were used for the analysis. In the WECS forecast, three scenarios of economic development have been taken into consideration - (i) Business as usual (4.5% GDP growth rate), (ii) Reference (7.2% GDP growth rate), and (iii) High growth (9.2% GDP growth rate). On top of the three scenarios, additional forecast was done for various policy interventions, e.g. 100% of the cooking with electricity and 75% of water heating with electricity in urban areas by 2020, metro in cities by 2025, etc., scenarios at 7.2% and 9.2% GDP growth rate. Although the original WECS study covers a 25-year planning horizon [25], only the demand forecast for 2030 has been taken for analysis in this study.

Combining the 24 generation mix scenarios with the five load forecast scenarios results in a total of 120 scenarios, enabling a comprehensive assessment of the flexibility requirements of the future Nepalese power system.

System data

Secondary data were collected and analyzed to prepare the following datasets for the flexibility analysis.

The installed capacity is 3093 MW with 2090 MW RoR, 790 MW PRoR and 106 MW storage hydropower with 107 MW solar PV plants. There are six PRoR plants operating currently with 4-6 hours of peaking capability contributing to around 3518 MWh of pondage capacity. The storage capacity for the storage hydropower is taken as 98873 MWh, which is calculated based on the net reservoir capacity of the power plant. There is only one hydropower plant, namely Kulekhani hydropower plant, which has three cascade projects with combined capacity of 106 MW, with seasonal storage facility inside the country. The storage capacity of the storage hydropower plant is 73.3 million m^3 which is equivalent to 98873 MWh capacity for 550 m effective head of the power plant [17].

The existing interconnection capacity between Nepal and India including the main Dhalkebar-Mujaffarpur 400 kV transmission line is around 1400 MW. However, the approved export power capacity from Government of India is 700 MW only [18].

Hydro Inflow

The inflow variation for hydro power plants was developed based on historical hydrological data to reflect the pronounced seasonal variation between wet and dry months. RoR hydropower is treated as a VRE source due to its dependence on river flow. For storage hydropower plant, the reservoir capacity will determine how the inflow variation affect the operation. The parameters for the storage hydropower include installed capacity (MW) and reservoir size (GWh). The inflow variation of the power plants is calculated approximately based on the average capacity variation of the power plants from historical data. The inflow variation causes capacity of hydropower fall to as low as 34% of the installed capacity as shown in Figure *3*.

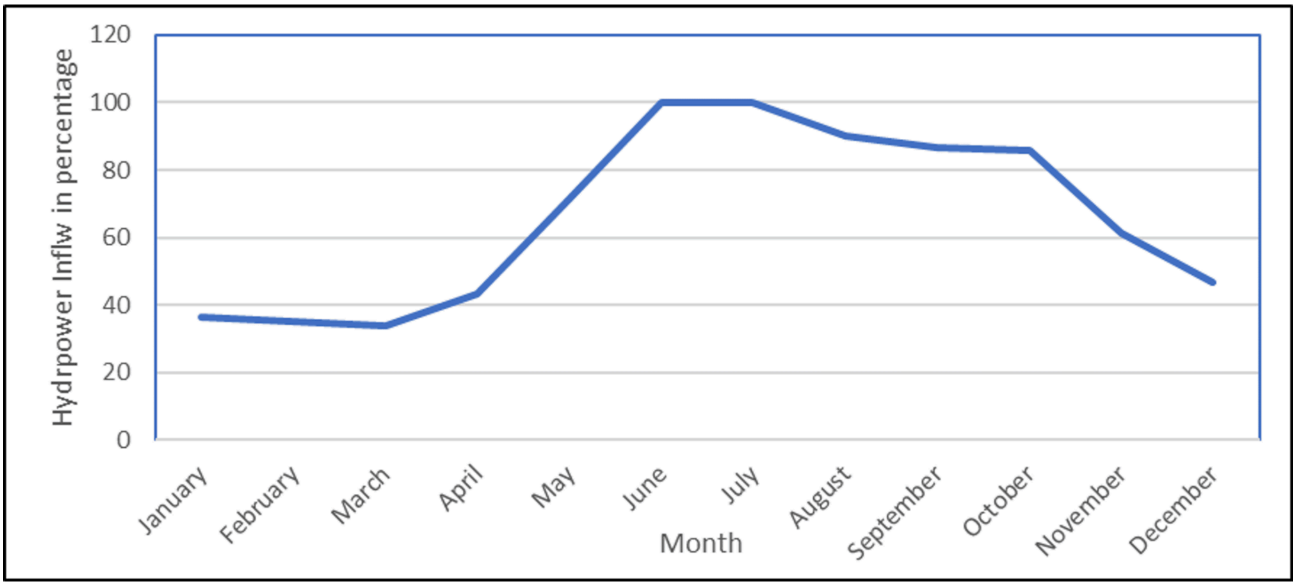

FIGURE 3: Typical inflow variation for hydropower plants in Nepal

Solar PV

Solar PV is modeled based on installed capacity (MW) and a representative hourly generation profile (in pu of installed capacity) derived from typical meteorological year data for Nepal [27,28] as shown in Figure *4*.

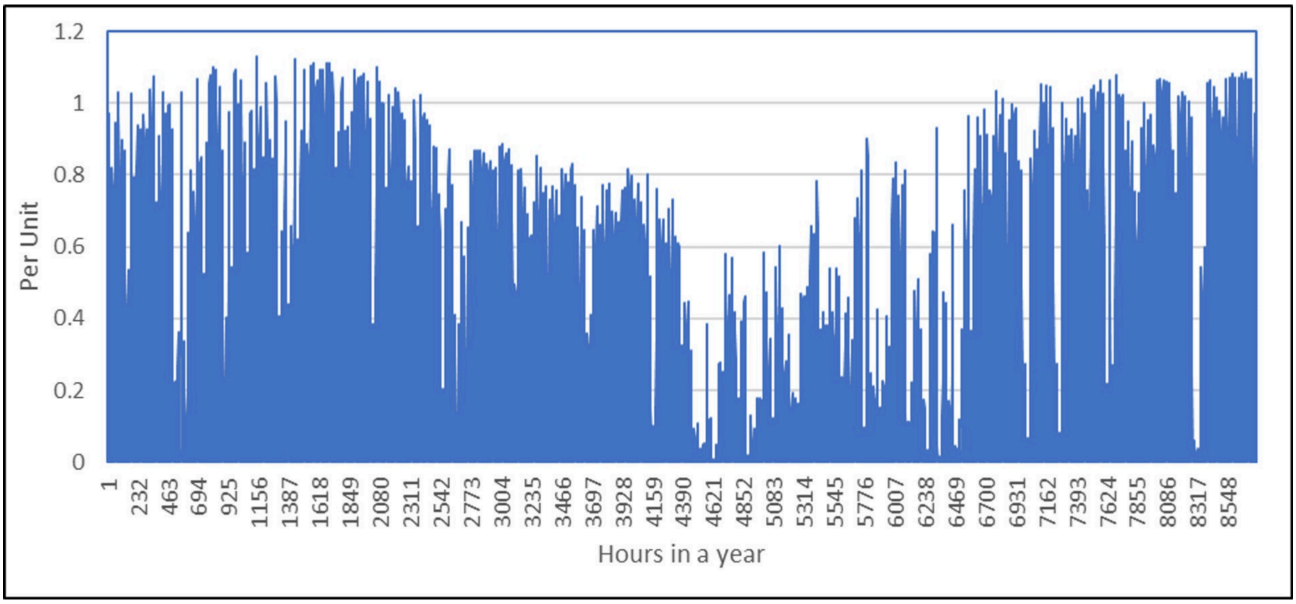

FIGURE 4: Solar capacity variation based on irradiance variation for each hour in a year

Load Profile

An hourly load profile for the year 2024, representing the current demand pattern of the INPS, was obtained from NEA operational data [18]. To reduce the computational time, each month is represented by one representative daily load profile. The annual energy demand of the country is 12681000 MWh. The demand profile is as shown in Figure *5*. Based on the availability of the demand data in the public profile, representative daily load profile for each month was used for analysis. The peak demand of the country is 2212 MW occurring in the month of May.

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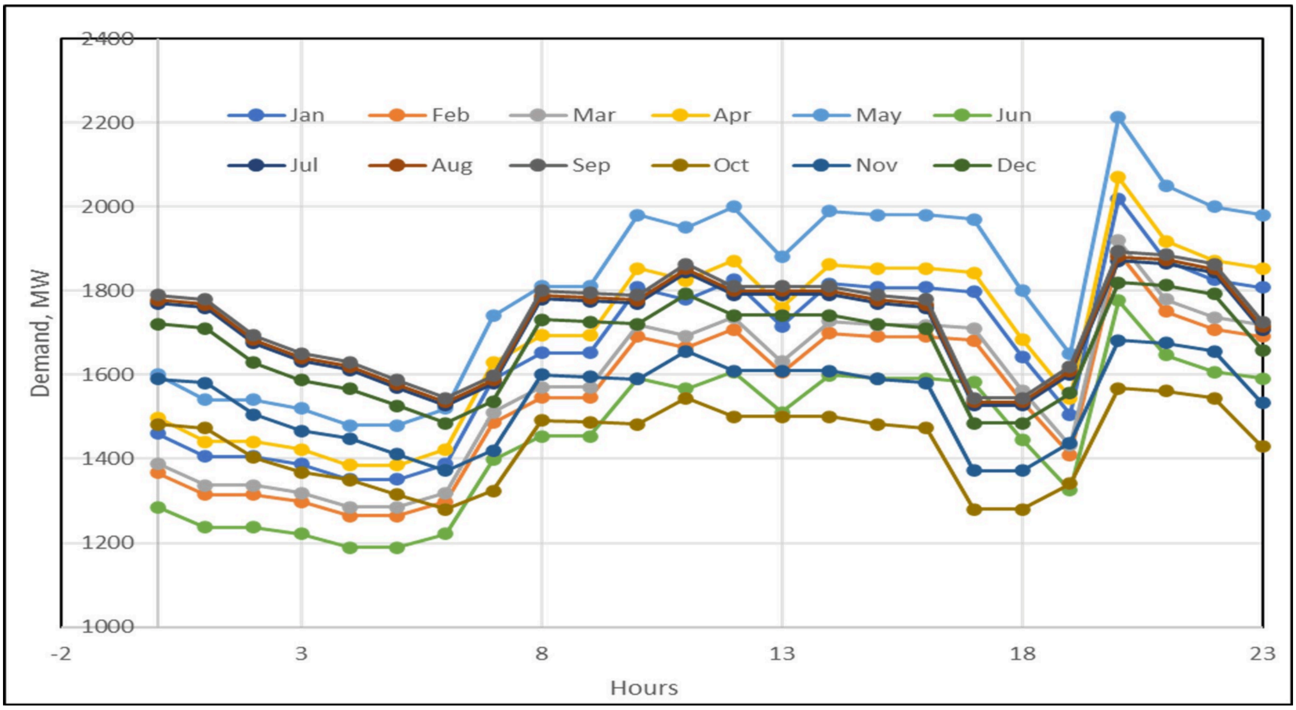

FIGURE 5: Representative daily load profile for each month

For future scenarios (2030), this baseline profile was scaled according to official demand growth forecasts from WECS. Figure *6* represents the forecast by WECS from 2015 to 2040 for five different scenarios: Business as Usual (BAU), Reference Scenario (7.2% GDP growth), High Scenario (9.2% GDP growth), 7.2% growth with policy intervention, and 9.2% growth with policy intervention [25].

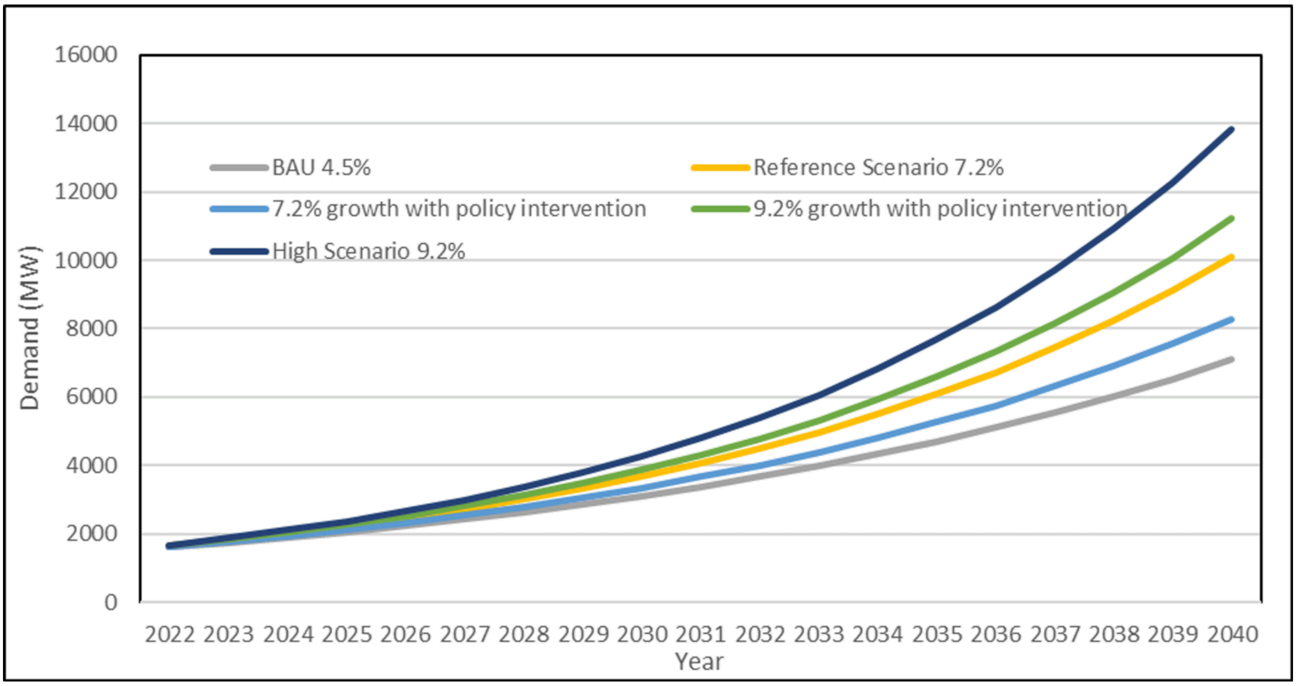

FIGURE 6: National Load forecast for Nepal

Cross-border Electricity Trade (CBET) with India

To evaluate the impact of CBET on system flexibility, an import/export scenario was incorporated for the base year. In practice, the NEA undertakes CBET with India through various mechanisms such as Government-to-Government agreements, Power Exchange Corporation market and bilateral contracts with Indian states. In 2023 the Government of India approved the import of up to 200 MW of electricity from Nepal during the monsoon months (June to November) for a period of five years, while an additional 300 MW was permitted for trading in the Indian electricity market [18]. Depending on the prevailing generation and demand conditions, the load dispatch center utilizes imports and exports as an operational flexibility option.

Four representative import/export profiles were developed for the base year. The first profile represents a simplified seasonal pattern, with imports of 400 MW during the dry months (January-April and December), limited exports during May, and exports of up to 400 MW during the wet season (June-November). The remaining three profiles represent progressively more realistic trading patterns based on existing practices, where imports during dry season are limited or avoided during peak demand hours, while exports during the wet season vary between 350 and 500 MW depending on the availability of surplus energy. These profiles were designed to capture different levels of cross-border trading capability and operational constraints. The corresponding monthly profiles are shown in Figure *7*.

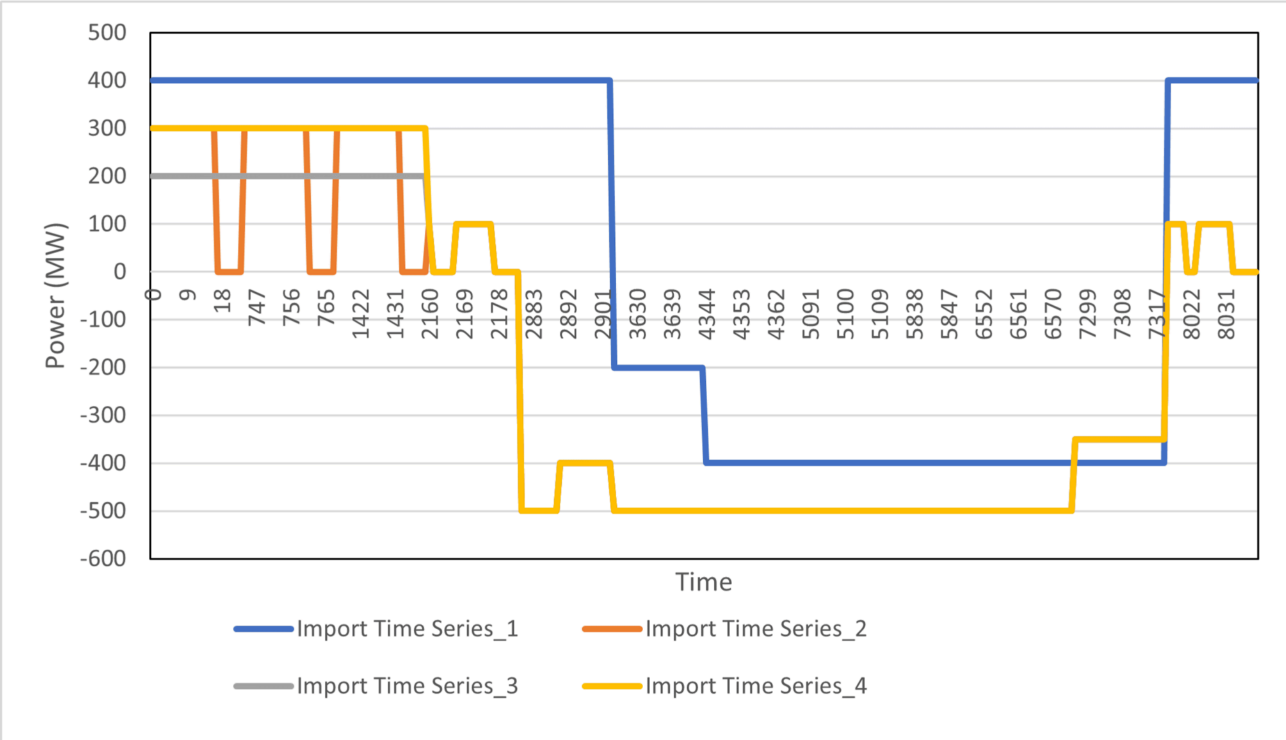

FIGURE 7: Time series of cross-border electricity trade volume in MW (positive indicates import and negative indicates export)

Discussion

This section presents the findings from the diagnostic flexibility analysis of INPS for the base year 2025 and future scenarios for 2030.

The flexibility of the INPS in each scenario is quantified using a set of key performance indicators derived from the FlexTool simulation outputs. These metrics provide a comprehensive view of both flexibility deficits (inability to meet demand) and flexibility surpluses (inability to utilize available energy).

· Loss of load (MW): The maximum hourly power deficit during the year. It indicates the system's inability to meet peak demand at a specific moment and is a direct measure of capacity inadequacy.

· VRE Curtailment (Max MW): The highest single-hour curtailment of VRE generation (combined solar PV and RoR plants) in MW. This metric identifies moments of generation surplus, often occurring during midday hours with high solar generation and low demand.

· Annual VRE Curtailment (GWh): The total energy from VRE sources that could not be utilized by the grid over the entire year. It quantifies the total economic loss from wasted renewable energy due to insufficient system flexibility.

· Annual Reservoir Spill (GWh): The total energy equivalent of water spilled from storage reservoirs over the year. This occurs when reservoirs are full and inflows cannot be stored or used for generation, representing a loss of valuable, dispatchable energy.

Flexibility analysis for base case (2025)

The base case annual energy demand of INPS is 12681 GWh (12681000 MWh) with an annual peak load of 1966 MW. The generation is heavily dominated by VRE, with RoR hydro and solar PV constituting 91.58% of the energy mix. While this high VRE share is positive from a renewable energy perspective, the system exhibits significant flexibility challenges as summarized in Table *3*. Figure *12* shows the loss of load variation for the 11,769 MW installed capacity scenario with 10% solar PV and 10% PRoR. Compared to the 8,937 MW scenario, the higher generation capacity substantially improves system adequacy. Loss of load is eliminated under the BAU, Reference, High scenarios, and policy intervention with 7.2% GDP growth scenario with less than 10% storage requirements, while the policy intervention scenario with 9.2% GDP growth requires additional storage capacity to maintain reliability. When the PRoR share is increased to 25%, no loss of load is observed under any of the considered demand scenarios.

Flexibility issues	Base Case with PRoR aggregated as RoR	Base Case Actual
Loss of load (max MW)	637.15	794.13
Curtailment (max MW)	1823.23	1033.23
Curtailment (TWh/a)	5.22	1.93
Spill (TWh/a)	0.27	3.42

TABLE 3: Flexibility metrices for base case

RoR, run-of-river; PRoR, peaking run-of-river

When the PRoR capacity is aggregated with RoR hydropower, the system is unable to meet 5.68% of the annual energy demand, corresponding to a substantial energy deficit of 720,379 MWh. The peak capacity shortfall reaches 637.15 MW, indicating severe stress on the system during periods of high demand and low hydrological inflows. Conversely, the system suffers from substantial overgeneration during the wet season, resulting in a maximum VRE curtailment of 1,823.23 MW, and annual curtailed energy of 5.22 TWh. This represents a significant loss of available clean energy.

When PRoR plants are modeled with their pondage capacity, the annual energy deficit decreases to 585,226 MWh, equivalent to 4.62% of annual demand. With the inclusion of 790 MW of PRoR plants with approximately 3518 MWh storage, the system is able to serve an additional of 135,153 MWh of annual energy demand. The loss of load, however, increases to 794.13 MW. This is mainly attributed to the optimized dispatch strategy adopted by the model. Instead of operating continuously, PRoR plants store water during certain periods and release it during other hours to completely meet the system load, thereby reducing the duration and frequency of supply shortages.

The inclusion of PRoR substantially reduces maximum VRE curtailment from 1,823.23 MW to 1,033.23 MW, approximately equal to the installed PRoR capacity. Since PRoR plants possess limited storage capability, they are not treated as VRE sources by the model. However, the increased operational flexibility results in a significant rise in reservoir spill, which increases from 0.27 TWh to 3.42 TWh annually.

These results indicate that maximum loss of load alone is insufficient to characterize system flexibility. Although the maximum loss of load increases, PRoR integration improves system performance by reducing annual energy deficits and renewable curtailment. However, its short duration storage capacity is insufficient to address the pronounced seasonal imbalance of the Nepalese power system. Figure *8* and Figure *9* illustrate the hourly dispatch for the base case without and with explicit PRoR representation.

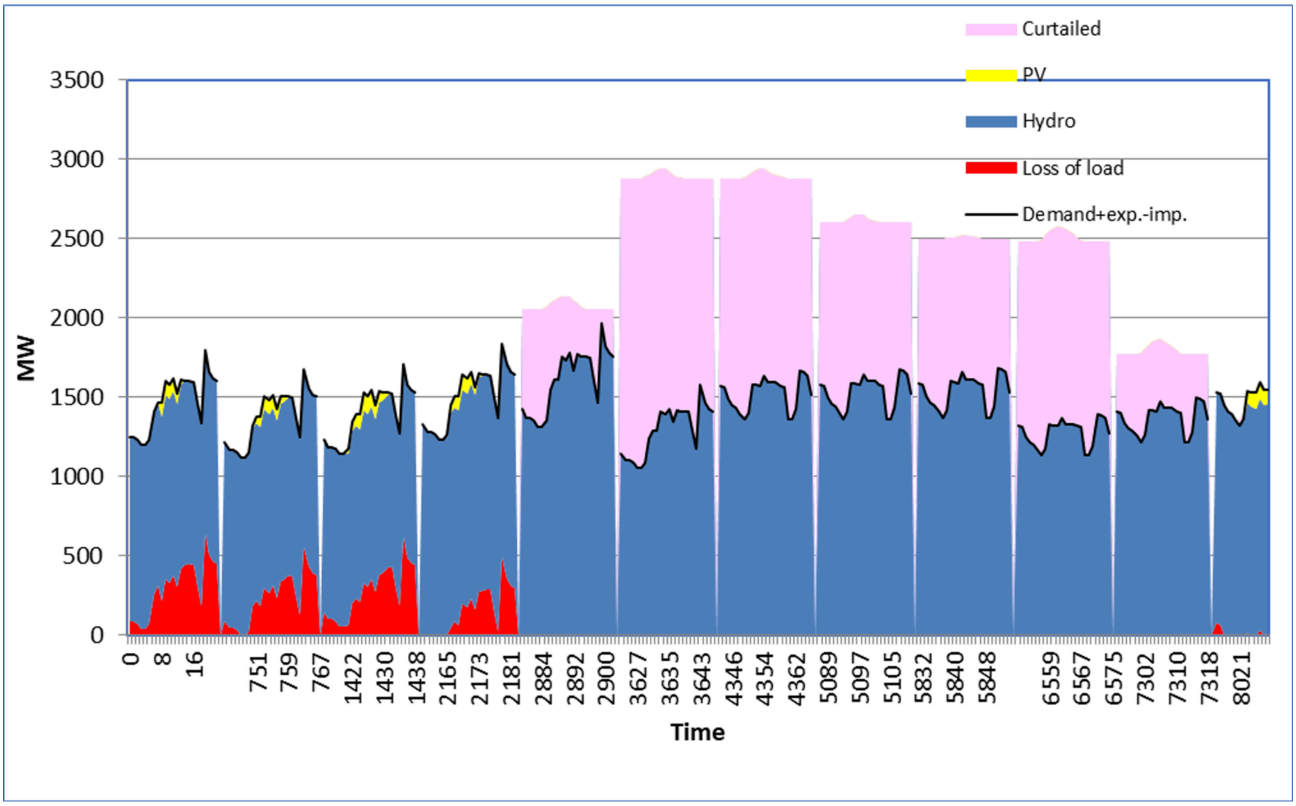

FIGURE 8: Hourly dispatch for each day of month for base case when PRoR is aggregated as RoR

PV, Photovoltaic; RoR, run-of-river; PRoR, peaking run-of-river

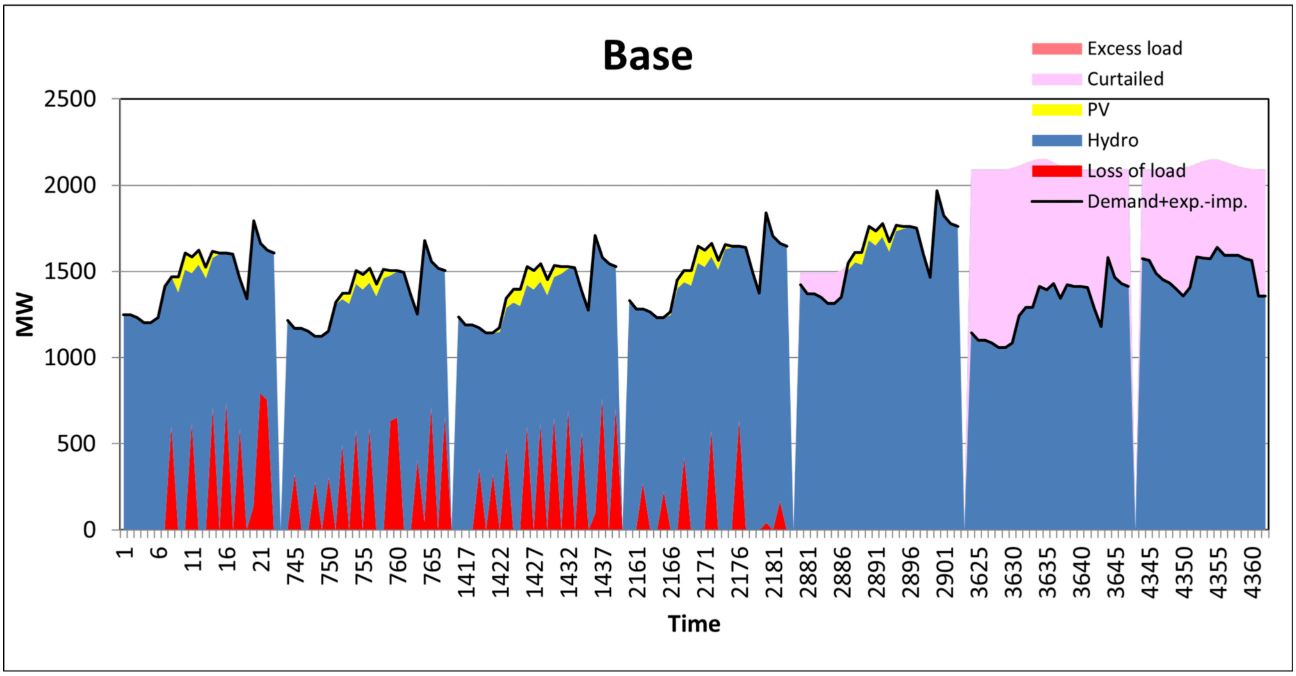

FIGURE 9: Hourly dispatch for each day of month for actual base case

PV, Photovoltaic

These initial findings underscore a critical imbalance between generation and load profiles in the base case system. The flexibility issues are deeply rooted in Nepal's distinct seasonal hydrology.

Dry Season (Primarily January-April): Reduced river inflows significantly decrease RoR and PRoR generation while electricity demand remains relatively high. This mismatch results in frequent loss-of-load events. When PRoR plants are represented as RoR generation, the model records the number of daily shortage events as 24, 22, 24, and 17 in January, February, March, and April, respectively. Explicit representation of PRoR substantially improves short-term balancing capability, reducing the number of daily shortage events to 9, 12, 11, and 7, respectively.

Wet Season (Primarily May-November): This period sees abundant river inflows and maximum hydropower generation. When generation exceeds demand, large amounts of renewable energy must be curtailed. The introduction of PRoR plants reduces renewable curtailment owing to their limited dispatchability and short-duration storage capability.

Overall, the results confirm that the INPS faces a classical energy-shifting problem characterized by energy surpluses during the wet season and energy deficits during the dry season. This indicates that long-duration and seasonal storage resources are essential for improving system flexibility.

Flexibility analysis considering CBET

Table 4 shows the flexibility metrices under four different CBET profile in the base case. The CBET significantly improves the flexibility of the INPS. Among the four trading profiles considered, import time-series 1 and import time-series 4 completely eliminate loss of load, while import time-series 2 and import time-series 3 reduce the annual unserved energy to 119062 MWh and 120074 MWh, respectively.

Flexibility issues	Base Case with import time-series 1	Base Case with import time-series 2	Base Case with import time-series 3	Base Case with import time-series 4
Loss of load (max MW)	0	829. 98	685.99	0
Curtailment (max MW)	849.12	527.94	528.12	526.55
Curtailment (TWh/a)	0.99	0.33	0.33	0.33
Spill (TWh/a)	3.91	2.68	2.65	2.75

TABLE 4: Flexibility metrices considering CBET in base case

CBET, cross-border electricity trade

Although the maximum loss of load in the actual base case reaches 794.13 MW, the simulations indicate that a maximum import requirement of only 368 MW is sufficient to eliminate annual energy shortages. In other words, the existing storage and PRoR hydropower combined with a moderate level of cross-border exchange, enable the system to optimally redistribute energy and satisfy annual demand.

The results further indicate that cross-border trade enhances flexibility not only by acting as an external source and sink of energy but also by improving the internal utilization of existing flexible resources. Through coordinated imports and exports, the dispatch of PRoR and storage hydropower plants becomes more efficient, leading to reduced renewable energy curtailment. Under import time-series 1, the maximum curtailed power decreases to 849.12 MW, while annual curtailment falls to 0.99 TWh. Additional reductions could be achieved by prioritizing domestic generation over imports during surplus periods.

These results highlight the important role of CBET as an external flexibility resource capable of mitigating seasonal imbalances in the Nepalese power system. While CBET can provide valuable external flexibility, long-term generation planning from an energy security perspective requires development of adequate domestic flexibility resources. Therefore, the following analysis investigates the role of storage hydropower as an internal flexibility resource for addressing the seasonal imbalance inherent in the INPS.

Flexibility improvement via storage hydropower

To assess the role of storage hydropower as an internal flexibility source, the study analyzed the impact of systematically increasing the share of storage hydropower to 15%, 20% and 25% of the generation mix, while keeping PRoR and solar capacity constant. The key results are summarized in Table *5* and Table *6*.

General results	Base Case	Base Case with 15% Storage	Base Case with 20% Storage	Base Case with 25% Storage
VRE share (% of annual demand)	81.5	74.57	70.46	65.23
Loss of load (% of annual demand)	4.62	0	0	0

TABLE 5: Percentage of VRE share and percentage of annual demand not served with increasing storage hydro mix

VRE, variable renewable energy

Flexibility issues	Base Case	Base Case with 15% Storage	Base Case with 20% Storage	Base Case with 25% Storage
Loss of load (max MW)	794.13	0	0	0
Curtailment (max MW)	1033.23	675.23	520.23	366.23
Curtailment (TWh/a)	1.93	0.74	0.36	0.13
Spill (TWh/a)	3.42	4.03	4.40	4.64

TABLE 6: Flexibility metrices for varying storage hydro mix for base case

The most significant impact of increasing storage hydropower is the significant improvement in system reliability. With a storage share of 15%, the system is able to completely eliminate loss of load, indicating that seasonal storage is highly effective in addressing the energy imbalance inherent in the existing generation mix. Storage hydropower absorbs excess generation during the wet season and shifts it to deficit periods in the dry season. Consequently, both peak curtailment and annual renewable energy curtailment decline substantially. Peak curtailed power decreases from 1,033.23 MW in the base case to 366.23 MW at 25% storage, while annual curtailed energy falls from 1.93 TWh to only 0.13 TWh.

An opposing trend is observed for reservoir spill, which increases from 3.42 TWh to 4.64 TWh with increasing storage penetration. This indicates that while storage projects effectively reduce renewable curtailment and improve reliability, reservoir inflows during the wet season eventually exceed the available storage capacity, resulting in increased spillage. This phenomenon suggests that additional optimization measures, such as coordinated reservoir operation or enhanced export capability may be required to fully utilize the surplus energy.

Overall, the results demonstrate that seasonal storage hydropower is the most effective domestic flexibility resource for addressing Nepal's seasonal energy imbalance. Even moderate increases in storage capacity significantly improve reliability and renewable energy utilization, thereby supporting the strategic role of storage hydropower in future generation planning.

Flexibility analysis of 2030 scenarios

The analysis was extended to 2030 to assess system adequacy under different generation capacity and mix scenarios and five demand growth scenarios: Business as Usual (BAU), Reference Scenario (RS), High Scenario (HS), 7.2% growth with policy intervention (PI_7.2), and 9.2% growth with policy intervention (PI_9.2). The results focus on the maximum loss of load (in MW) as a key indicator of system flexibility and adequacy.

Figure *10* illustrates the variation of maximum loss of load with increasing storage hydropower share for the 8,937 MW installed capacity scenario with solar PV and PRoR shares fixed at 10% each. Under the BAU demand scenario, the available generation capacity is sufficient to eliminate loss of load even with less than 10% storage hydropower. However, as demand growth increases, storage hydropower becomes increasingly important in maintaining system reliability. In particular, the policy intervention scenarios exhibit the highest flexibility requirements, necessitating substantially larger storage capacities.

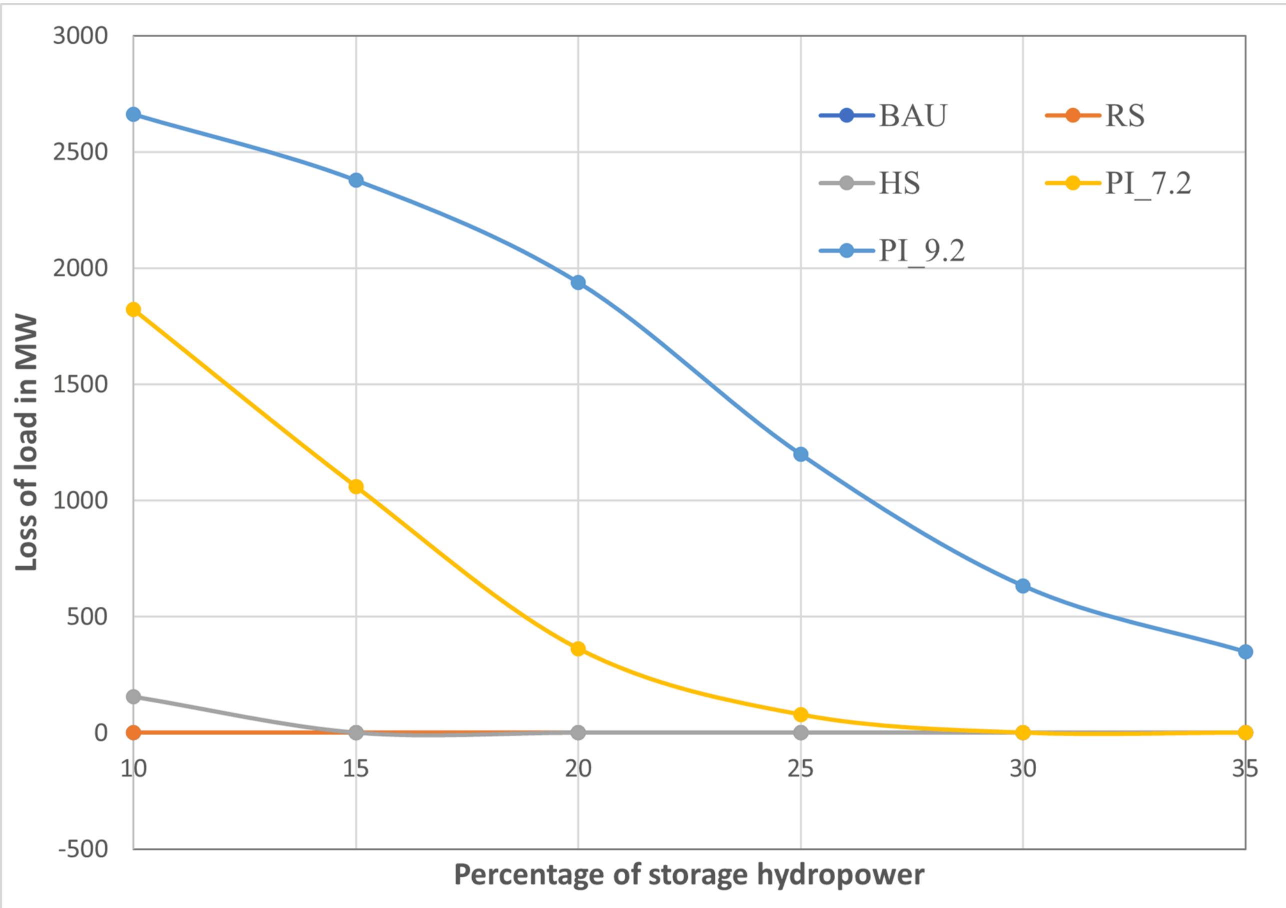

FIGURE 10: Maximum loss of load variation in 2030 at 8937 MW generation capacity with 10% solar PV and 10% PRoR hydropower

PV, Photovoltaic; PRoR, peaking run-of-river

Figure *11* illustrates the corresponding results for the total capacity of 8,937 MW with the PRoR share increased to 25%. Increasing the PRoR share improves short-term operational flexibility and reduces the storage requirement under all load scenarios. Nevertheless, under the high-growth and policy intervention scenarios, significant loss of load persists, indicating that increased PRoR capacity alone is insufficient to compensate for an inadequate total generation capacity.

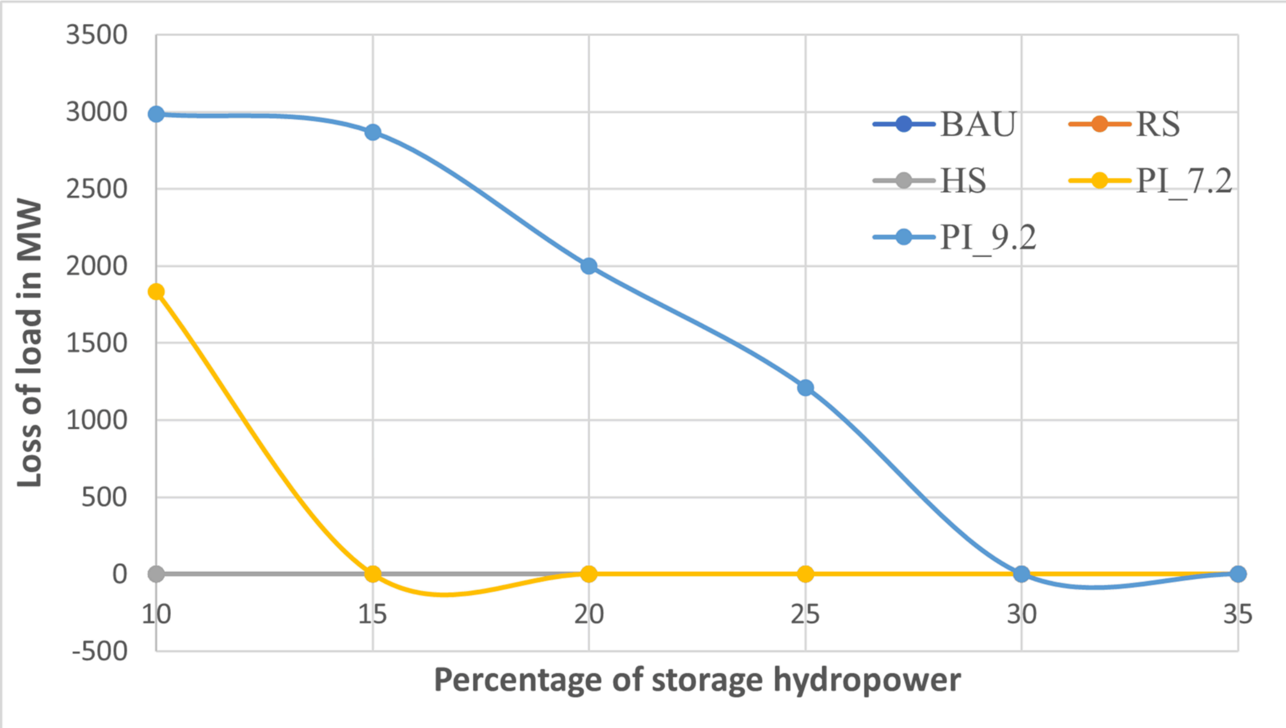

FIGURE 11: Maximum loss of load variation in 2030 at 8937 MW generation capacity with 10% solar PV and 25% PRoR hydropower

PV, Photovoltaic; PRoR, peaking run-of-river

Figure *12* shows the loss of load variation for the 11,769 MW installed capacity scenario with 10% solar PV and 10% PRoR. Compared to the 8,937 MW scenario, the higher generation capacity substantially improves system adequacy. Loss of load is eliminated under the BAU, Reference, High scenarios, and policy intervention with 7.2% GDP growth scenario with less than 10% storage requirements, while the policy intervention scenario with 9.2% GDP growth requires additional storage capacity to maintain reliability. When the PRoR share is increased to 25%, no loss of load is observed under any of the considered demand scenarios.

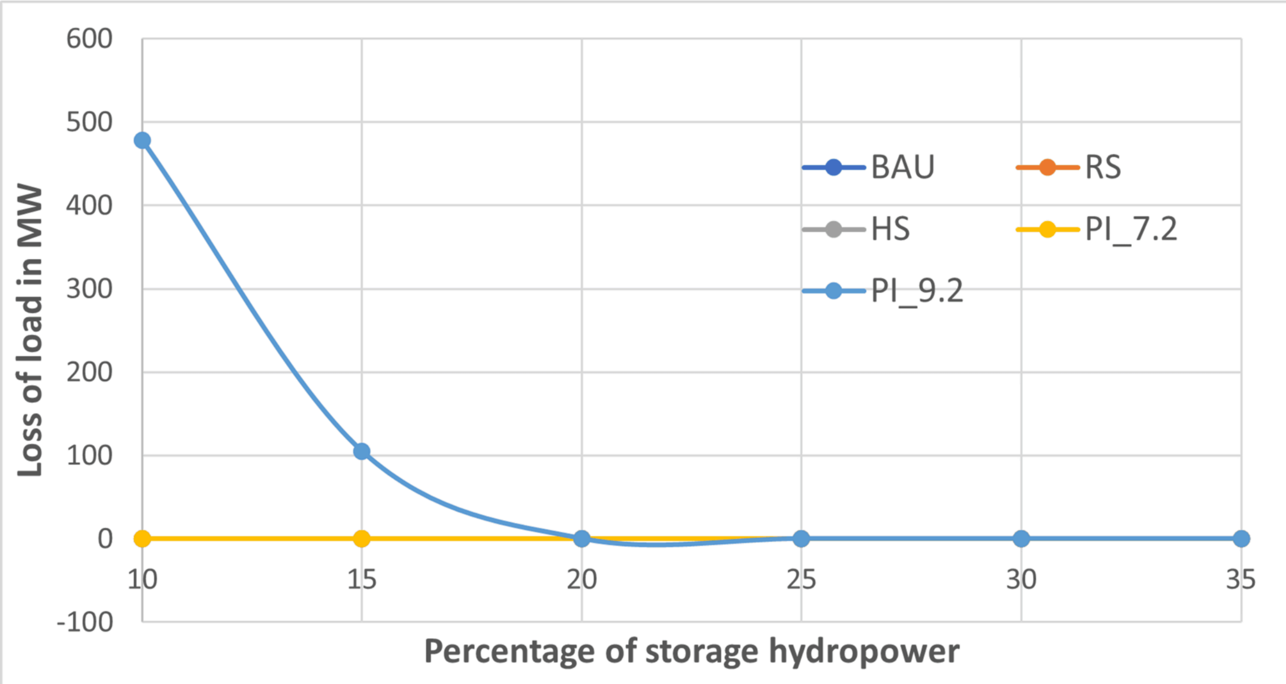

FIGURE 12: Maximum loss of load variation in 2030 at 11769 MW generation capacity with 10% solar PV and 10% PRoR hydropower

PV, Photovoltaic; PRoR, peaking run-of-river

Figure *13* summarizes the minimum storage hydropower share required to eliminate loss of load for all combinations of generation capacity, PRoR share, and demand growth scenarios.

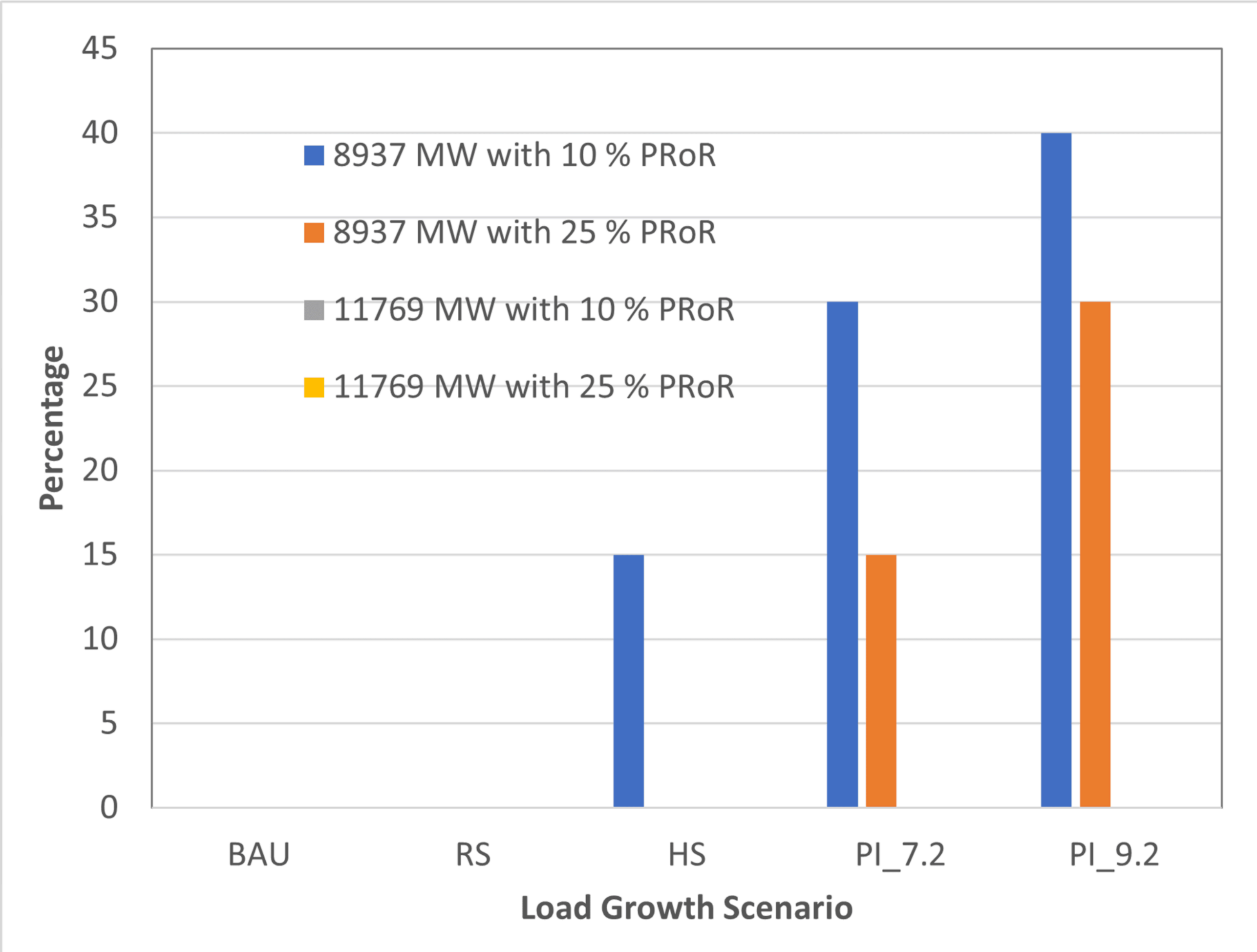

FIGURE 13: Percentage of storage hydropower required to eliminate loss of load under various scenarios in 2030

The results reveal that the 8,937 MW capacity scenario is inadequate under high growth and policy intervention scenarios and requires at least 15% storage hydropower under high growth and more than 30% for policy intervention scenarios. In contrast, the 11769 MW capacity target provides a robust system adequate to meet the loads with modest storage requirements. Overall, the results suggest that ensuring reliability under ambitious electrification pathways requires a dual strategy consisting of: (i) expansion of total installed capacity to at least the 11,769 MW target, and (ii) simultaneous development of flexible resources, particularly storage hydropower. Neglecting either capacity adequacy or flexibility enhancement is likely to result in substantial supply shortages and reduced system reliability.

Economic implications of storage hydropower

Storage hydropower projects generally require substantially higher capital investments than RoR projects. According to IEA estimates, the investment cost of hydropower projects typically ranges from approximately 1000-3500 USD/kW for RoR hydropower, 1050-7650 USD/kW for reservoir-based storage hydropower with a lower cost profile for PRoR hydropower. The levelized cost of electricity (LCOE) of hydropower is around 0.057 USD/kWh while utility-scale solar PV exhibits the LCOE of around 0.043 USD/kWh in 2024 [29].

However, the flexibility assessment demonstrates that a low-cost, RoR-dominated generation portfolio incurs loss of load and unserved energy and renewable energy curtailment. For the 2025 base case, the system experiences a loss of load equivalent to 585 GWh and annual renewable energy curtailment of 1.93 TWh. Increasing the share of storage hydropower progressively reduces curtailment to 0.74 TWh, 0.36 TWh, and 0.13 TWh for storage shares of 15%, 20%, and 25%, respectively. Similarly, the 2030 scenarios show that increasing storage capacity can simultaneously reduce loss of load and curtailment, thereby improving both reliability and renewable energy utilization. For example, in the 8,937 MW generation scenario with 10% solar PV and 10% PRoR hydropower, annual curtailment under the BAU load scenario decreases from 17.77 TWh at a 10% storage share to 6.54 TWh at a 35% storage share, representing a reduction of approximately 63%. Under the Reference Scenario, annual curtailment decreases from 13.70 TWh to 3.88 TWh, corresponding to a reduction of nearly 72%. Similar trends are observed for the remaining demand scenarios, as shown in Figure *14*.

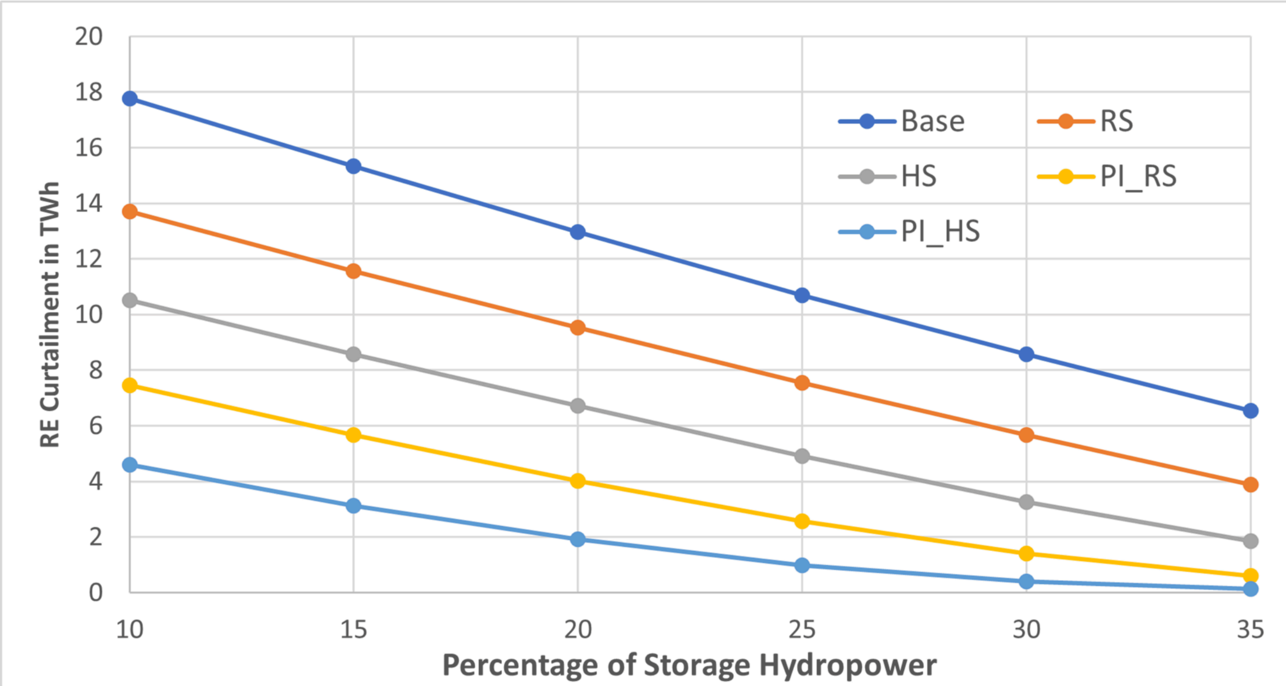

FIGURE 14: RE curtailment in TWh for 2030 in 2030 at 8937 MW generation capacity with 10% solar PV and 10% PRoR hydropower

PV, Photovoltaic; PRoR, peaking run-of-river

Generation planning should consider both energy costs and flexibility benefits rather than relying solely on the LCOE of individual technologies. Although storage hydropower exhibits a higher LCOE than other projects, its ability to shift energy seasonally, reduce renewable energy curtailment, and improve system adequacy provides additional system value that is not captured by conventional LCOE comparisons.

A detailed techno-economic assessment incorporating project-specific investment costs, environmental impacts, and benefit-cost analysis is beyond the scope of the present flexibility study. Such analyses, together with optimization of generation expansion and storage sizing, constitute important areas for future research.

Conclusions

This study presented a diagnostic assessment of the flexibility of the INPS under present and future scenarios. The results confirm that the heavy dependence on RoR hydropower creates a pronounced seasonal imbalance characterized by energy deficits during the dry season and substantial renewable energy surpluses during the wet season.

For the 2025 base case, explicit modeling of PRoR plants reduced the annual unserved energy from 720 GWh to 585 GWh and reduced annual renewable energy curtailment from 5.22 TWh to 1.93 TWh. However, the existing system still exhibits significant flexibility limitations. The results further show that CBET can act as an important external flexibility resource. With moderate levels of imports and exports, annual energy shortages can be eliminated with a maximum import requirement of only 368 MW, highlighting the importance of regional power exchange in improving system adequacy.

The analysis demonstrates that storage hydropower is the most effective domestic flexibility resource for mitigating seasonal imbalances. Increasing the storage hydropower share to 15%, 20%, and 25% reduces annual renewable energy curtailment from 1.93 TWh to 0.74 TWh, 0.36 TWh, and 0.13 TWh, respectively, while completely eliminating loss of load. These results underline the importance of seasonal storage resources for improving both reliability and renewable energy utilization.

The 2030 analysis reveals that future flexibility requirements are strongly influenced by both demand growth and generation mix. Under the lower capacity target of 8,937 MW, significant supply shortages persist under high-growth and policy intervention scenarios despite increased storage penetration. In contrast, the 11,769 MW capacity target together with higher PRoR penetration substantially improves system flexibility and can eliminate loss of load under all considered demand scenarios. The results also show that increasing storage penetration simultaneously reduces renewable energy curtailment, with annual curtailment in the 8,937 MW scenario decreasing from 17.77 TWh to 6.54 TWh under the BAU scenario as storage share increases from 10% to 35%.

Overall, the study highlights that future generation planning in Nepal should consider flexibility as a key planning criterion in addition to installed capacity and energy production. While CBET provides valuable external flexibility, adequate domestic flexibility resources are essential from an energy security perspective. The findings demonstrate that a balanced combination of generation expansion, PRoR development, seasonal storage hydropower, and CBET is required to ensure reliable and efficient operation of the Nepalese power system.

The present study is limited by its single-node representation and simplified treatment of cross-border electricity exchange. Future work should focus on multi-node modeling, optimization of storage sizing and PRoR operation, and co-optimization of CBET based on hydrological forecasts and market conditions. In addition, detailed techno-economic analyses incorporating investment costs, environmental impacts, and benefit-cost assessments are recommended to support long-term planning decisions.

Additional Information

Author Contributions

All authors have reviewed the final version to be published and agreed to be accountable for all aspects of the work.

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Disclosures

Human subjects: All authors have confirmed that this study did not involve human participants or tissue. **Conflicts of interest:** In compliance with the ICMJE uniform disclosure form, all authors declare the following: **Payment/services info:** All authors have declared that no financial support was received from any organization for the submitted work. **Financial relationships:** All authors have declared that they have no financial relationships at present or within the previous three years with any organizations that might have an interest in the submitted work. **Other relationships:** All authors have declared that there are no other relationships or activities that could appear to have influenced the submitted work.

Data Availability Statements

The datasets (and/or code) supporting this study are available from the corresponding author upon reasonable request.

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