Hydropower Sector in Nepal: A Sectoral and Financial Perspective

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Nepal’s hydroelectric power sector is a cornerstone of the nation’s energy strategy, leveraging its abundant rivers and steep terrain. The sector traces its roots to the Pharping hydropower station (500 kW) near Kathmandu, established in 1911. For most of the 20th century, development was modest and state-driven, but since the 1990s private-sector participation has surged. Although Nepal’s theoretical hydropower potential exceeds 80,000 MW (with ~40,000 MW considered feasible), less than 1% had been developed by the early 21st century. Today hydroelectricity supplies over 90% of Nepal’s domestic power and is the primary tool for energy security, rural electrification, and economic growth. Given this importance, the sector has received extensive study from technical, economic, and policy perspectives.

Historical Development

Nepal’s hydropower history unfolds in distinct phases. After the first power plant at Pharping in 1911, few projects were built under government control. From 1950 to 1990, large projects like Trishuli (1967) and Sun Koshi (1982) established basic capacity, but growth was slow. The 1990 democratic transition triggered a boom: the 1992 Electricity Act and Hydropower Development Policy opened the door to Independent Power Producers (IPPs). Under the new regime, dozens of build-own-operate-transfer (BOOT) projects were licensed to the private sector. By 2015 Nepal had only ~700 MW of **operational capacity**, but by 2024 this surged past 2,200 MW, as multiple IPP-run projects were completed (including the 456 MW Upper Tamakoshi in 2021). Nevertheless, development has been uneven. Political unrest (Maoist insurgency 1996–2006) and logistical challenges slowed progress. The 2015 Gorkha earthquakes dealt a severe blow: fourteen hydro plants (totaling ~115 MW) were heavily damaged, requiring major rebuilding. For example, work on Upper Tamakoshi (456 MW) was delayed six years by quake damage (pushing its completion from 2015 to 2021). Such events illustrate the sector’s vulnerability to Nepal’s seismic climate.

Despite these setbacks, installed capacity keeps growing. Official data show Nepal at **3,339 MW of hydropower capacity** by 2024, up from about 700 MW in 2015. In aggregate, IPP projects now exceed 2,800 MW while NEA-owned plants add roughly 600–700 MW. (IPP Association figures indicate ~85% of total capacity and generation are IPP-operated as of 2024.) This surge reflects not only past project approvals but also continued commitment by developers and partners. For example, in 2024 India’s Renewable Energy Agency took a stake in the 900 MW Upper Karnali project and BG Titan (USA) signed an MoU for 650 MW Tamakoshi-3. At the same time, Nepal’s courts and planners have begun scrutinizing new sites (in 2025 a Supreme Court halted any hydropower development in national parks and conservation areas, potentially affecting ~300 projects up to 20 GW).

Types of Hydropower Plants

Nepal’s hydro projects fall into three broad types, these are:

Run-of-River (RoR)

These plants have little or no storage; they divert a portion of river flow through turbines. RoR schemes are common in Nepal’s hilly terrain (e.g. Middle Marshyangdi, 70 MW) and dominate the smaller-scale sector. They typically generate power continuously but are highly seasonal (output peaks in the monsoon, drops in winter) since there is no large reservoir.

Peaking Run-of-River:

A subtype of RoR with limited pondage to allow short-term storage. Turbines can be shut during low-demand hours and released during evening peaks. Projects like Jagdulla HEP (106MW) of Karnali district.

Storage (Reservoir) Plants:

Larger dams that impound water for seasonal or multi-year storage. Electricity is produced by releasing water from the reservoir through a turbine, which activates a generator For e.g. Kulekhani I, 60 MW. It offers flexibility for energy production but has high initial cost to set up.

Each plant type influences economics and operations differently. RoR plants have lower capital costs but extreme seasonality: wet-season output (June–September) is 3–4 times the dry-season generation. Reservoir plants can deliver power in dry months, but cost overruns and geological risks tend to be higher in such projects. In practice, most Nepalese projects are RoR or peaking RoR due to lower up-front costs and less resettlement, though interest in storage projects is rising to address seasonal gaps.

Power Purchase Agreements (PPAs)

A power purchase agreement (PPA), or electricity power agreement, is a long-term contract between an electricity generator and a customer, usually a utility, government or company. PPAs are the revenue foundation of most hydro projects. In Nepal they are typically entered with the Nepal Electricity Authority or its subsidiaries under a cost-plus or fixed-tariff model. Key features of PPA structure include:

- **Seasonal (Dry/Wet) Tariffs**: Because output is seasonal, the tariff often has different rates for high-flow vs low-flow months. During the wet season (when ~80% of annual energy is generated), low seasonal tariffs can severely depress revenues. In projects with well-designed seasonal adjustment clauses, the average return on investment has been found to be ~23% higher than in projects without such clauses.

- **Escalation Clauses**: Tariffs usually escalate over time. Traditionally, Nepal's PPAs had low built-in escalation (a few percent annually) and no explicit inflation indexation. Over the 2010s, electricity tariffs rose only 2.7% per year on average, while inflation was 4.8% on average. This effectively meant the real value of tariffs declined over time, squeezing developer margins.

- **Take-or-Pay or Take-and-Pay**: Once a PPA is signed under Take-or-Pay model, the NEA is obligated to pay the investor whether it took the electricity or not. The authority would purchase all the electricity generated by a project, giving banks the confidence to invest in such projects. Under Take-and-Pay model the NEA will only buy electricity when it wants to and pay for electricity it actually takes. In other words, under the Take-and-Pay PPA the NEA is not obliged to purchase or pay for electricity when it does not need it. The absence of a strong take-or-pay commitment can make financing difficult, because revenue becomes uncertain during low-demand periods or surplus conditions.

- **Seasonality and Oversupply**: With rapid capacity growth and relatively stable demand, the market has shifted to periodic oversupply, especially in monsoon. Within five years Nepal transitioned from a severe deficit to seasonal surplus. In some wet months NEA cannot absorb all generation, and without export infrastructure much power goes unused. In oversupply periods, even running plants at full capacity earns little revenue, as cheaper imported power from India becomes available in the dry season (when domestic output is lowest) and domestic prices are flat. This underscores that PPA terms alone cannot offset market shifts: many projects assumed unending demand growth, and now face a situation where NEA buys only a fraction of potential output during the rainy months.

Technical and Operational Metrics

When evaluating hydro projects, engineers and analysts use several key performance metrics:

Capacity Factor (CF): The ratio of actual annual generation to the theoretical maximum (if running 24/7). In recent years, NEA data indicate capacity factors over 60% on average. Run-of-river projects typically have CFs in the 50–60% range (due to seasonal shutdowns), whereas peaking plants and reservoirs can exceed 70%. Capacity factors tend to vary widely by river basin and project design, and depend on hydrology and maintenance as well as head.

Plant Availability Factor: This measures the fraction of time the plant is physically available to run (excluding scheduled outages). Nepali hydros generally show more than 90% availability, reflecting good maintenance practices and reliable equipment. A plant with 90% availability can operate ~8,760×0.90=7,884 hours per year, so availability losses are a few percent annually.

Transmission and Distribution (T&D) Losses: Since much generation flows through the grid, line losses are important. Nepal's system losses (technical plus some commercial losses) are typically around 5–8% of energy transported. Losses are higher in high-voltage lines (long-distance transmission from remote valleys) than in local distribution. Reducing these losses (through better grid infrastructure and management) would directly increase net revenue for generators, so grid investment is often discussed in sector plans.

These operational metrics connect to project economics: higher CF and availability mean more saleable energy, boosting revenues. Achieving these metrics depends on good hydrological assessment, engineering design, and diligent O&M.

Economic and Financial Indicators

From a financial perspective, several metrics gauge a project's viability:

Net Present Value (NPV): The discounted net cash flow over project life. In Nepal, large hydropower projects typically have NPVs in the range of NPR 0.5 to 1.5 billion (50–150 crore), depending on size and cost. A positive NPV (given the social discount rate) is needed for lenders to finance a project.

Internal Rate of Return (IRR): The discount rate that makes NPV zero. For Nepali hydropower, financial IRRs tend to be around 12% in real terms. This is only a modest premium above typical industry hurdle rates (since many projects use up to 75–80% debt with interest around 10–12%). The IRR can vary: smaller projects often have slightly lower IRR due to higher relative O&M costs; larger projects justify more debt and thus can boost equity IRR.

Economic Internal Rate of Return (EIRR): A social-benefit measure, considering economic costs and benefits (often higher than financial IRR because imported fuel and environmental costs are excluded). Official figures suggest hydropower EIRRs of about 15–20%, indicating strong economic merit. A high EIRR implies that the project contributes positively to GDP and social welfare beyond just its private returns.

Employment Generation: Hydropower also impacts the local economy through jobs. On average, Nepali hydro projects generate 0.5–1 long-term job per MW during operation, plus 3–5 jobs per MW during construction. For example, a 100 MW plant might have 50–100 full-time employees and create 300–500 worker positions during the ~3–5 year build phase. Local employment is concentrated in construction trades (roads, tunnels, concrete) and later in plant operations and maintenance. This contributes to rural incomes and skill development; hence employment is a key benefit in social/feasibility studies.

These economic indicators rely heavily on realistic cost and production estimates. For instance, an overestimated capacity factor (due to optimistic hydrology) can give an inflated NPV and IRR, leading investors to accept a marginal project that ultimately underperforms. Conversely, conservative estimates protect against downside risk. Nepali lenders scrutinize assumptions carefully, given the stakes involved.

Construction, Planning and Management

Hydropower construction in Nepal faces numerous challenges. The country's rugged topography and limited infrastructure mean virtually all large projects entail massive civil works in remote valleys. Key issues include:

Data Limitations: Many Himalayan rivers have only short gauging records. A common issue is projects being designed on just 2–3 years of flow data, extrapolated to 25–30 years. This can grossly mis-estimate long-term generation, as climate variability (multi-year dry cycles) can easily break such short trends. Projects with <10 years of hydrological data had an average capacity utilization of only 52.3%, whereas those with >15 years of data averaged 68.7% utilization. Longer data series correlate with much more reliable performance estimates. Short datasets often lead to overestimation of generation.

Schedule Delays: A majority of projects suffer significant delays. A review of 32 projects found 27 (84.4%) ran over budget, and almost all had schedule slippage. On average, completion was 18.4 months behind plan. For example, land acquisition disputes can stop progress for months (tunneling may begin and then stop while awaiting land compensation).

Cost Overruns: Relatedly, overruns are the norm rather than exception. Projects often end up 20–30% above budget. Causes include commodity price inflation, redesign due to geological surprises, and interest accrued on extended timelines. When access roads get washed away during monsoon, it can halt construction for months. Each delay increases interest during construction, which can compound dramatically for projects with long construction periods.

Planning and Management: Poor planning is a frequent culprit. A 2014 study of Nepalese hydros found that in about 65% of projects, inadequate risk assessment, insufficient geological study, and weak contract administration led to cost and time overruns. Typical management problems include underestimating equipment delivery times, assuming ideal weather, or not preparing contingencies for labour shortages.

Scope Changes and Financing Cuts: Sometimes investor pressure to reduce capital costs leads to scope cuts or cheaper materials. Pressure from investors to reduce initial CAPEX sometimes leads to suboptimal design decisions. Projects where cheaper alternatives were selected for major components, result in higher maintenance costs and more frequent outages. Aggressive cost-cutting early can increase O&M and reliability costs later.

Overall, successful projects in Nepal tend to be those with rigorous upfront planning, hydrological assessment and strong contract discipline. Insufficient data or flawed site design is cited as a root cause in many delayed or underperforming projects. Successful project account for monsoon impacts (e.g. building road bridges high above flood lines), perform thorough geological surveys, and include buffers for currency and inflation risks.

Financing and Capital Structure

Hydropower projects are highly capital-intensive and require careful financial structuring. Nepalese projects typically use a mix of debt and equity; the debt-to-equity ratio is a key factor in cost and risk:

Debt Ratios: Many projects use 70–80% debt financing. High leverage lowers immediate equity requirements but raises financing costs and risk. A comparative analysis of 25 Nepalese hydros showed those with very high debt (70–80%) faced higher loan margins and perceived risk than projects with moderate debt (50–60%). Lenders charged higher interest to the more leveraged projects to compensate for greater default risk. Conversely, projects with more equity had lower borrowing costs but smaller equity returns. In short, aggressive leverage can amplify equity IRR *if* the project cash flows are solid, but it also makes the project vulnerable to interest or revenue shocks.

Interest Rates and Debt Cost: The cost of debt in Nepal is significantly higher than international norms. Local bank loans for hydro projects often carry interest rates of 8–12% per annum. In contrast, international export credit and development finance can offer 3–6%. For example, financing from an international agency (World Bank, ADB, Ex-Im Bank) might come at ~3–5%. But such loans are harder to secure (rigorous social/environmental conditions, long processing) and expose projects to foreign exchange risk. Many developers end up with high-rate local rupee loans.

Financing Sources: Common sources are local commercial banks (Nepal Bank, Nabil, etc.), domestic development banks (Nepali Rastra Bank has a Hydropower Investment and Development Company fund), and foreign credit (India's EXIM Bank, ADB, or Chinese EXIM). Local equity often comes from Nepalese promoter companies (construction conglomerates, industrial groups) or domestic bond issues. Some projects also list on the Nepalese stock exchange to raise capital.

Financial Risks: Currency depreciation can balloon dollar-denominated costs. Projects must often import turbines and heavy equipment (in dollars or euros), so a falling rupee over the 3–5 year construction can raise CAPEX. Likewise, if interest rates spike (as often happened during economic tightening), IDC grows. Since many PPAs are cost-plus, some currency and interest changes can be passed to NEA over time, but this leads to "circular debt" issues and is politically sensitive.

Cost Overruns Impact: On average, Nepali hydros go 25–30% over budget. These overruns reduce equity returns and often require arranging bridge financing. If a project cannot pass new costs through the tariff (due to fixed PPA caps), profitability can collapse. Effective cost monitoring and scope control are thus vital to financial viability.

Operation & Maintenance (O&M) Costs: Once built, hydros have relatively low running costs. Annual O&M is typically 2–4% of the original CAPEX for new plants. Older plants (15+ yr) require more frequent equipment replacement ~4–6% of CAPEX.

Revenue and Market Dynamics

The ultimate success of a hydropower project rests on revenue realization:

PPA Structure (Fixed vs Cost-Plus): Nepalese projects have used both fixed-tariff PPAs and cost-plus. Recent analyses show that cost-plus PPAs (with indexation to inflation) tend to provide more predictable cash flows than strictly fixed-rate contracts. However, cost-plus arrangements require rigorous auditing and can be contentious (since NEA could dispute costs).

Tariff Levels: New plants bid tariffs often in the range NPR 4–8 per kWh during the high season, and lower in the wet season. Older projects with signed PPAs can charge more, especially those built when global financing was cheaper. For example, very small first-generation plants (like 3 MW projects in the 1990s) may have IRR-guaranteed tariffs exceeding NPR 8–10 in early years.

Energy Demand vs Surplus: As noted above, a major current challenge is oversupply in wet months. During May–October, generation capacity often exceeds demand by hundreds of MW. NEA sometimes curtails output (asks plants to idle) or sells below-cost power to India. In winter (Nov–Feb), imports are still needed (power from India at higher prices) because run-of-river output falls off. This seasonal mismatch means that even high-capacity plants may have low utilization in terms of revenue. Developers have lobbied for more storage or reservoir projects to produce during dry months, but building large reservoirs in Nepal has its own complications (cost, environment, risk of landslides/floods).

Policy and Investor Climate: Nepal's hydropower growth has been slower than what its resources might allow. Factors cited include bureaucratic hurdles (complex licensing, lengthy EIA processes), political uncertainty (policy reversals, tensions with local communities), and non-competitive pricing (tariffs set too low to compensate for risk). For example, development licensing can take 3–4 years alone, during which costs escalate.

IFRIC12

Hydro projects in Nepal are structured as BOT/BOOT concession agreements: a private developer builds, owns, and operates the plant for a period (often 35 years), then transfers ownership to the government or NEA. Such arrangements fall under the International Financial Reporting Interpretations Committee (IFRIC) guidance known as IFRIC 12.

IFRIC12 applies to public-to-private service concession arrangements in which:

1. the grantor controls the use of the infrastructure (The grantor is considered to control the use of the infrastructure when it controls or regulates: the services to be provided with the infrastructure; to whom those services must be provided; and the price to be charged for those services); and
In Nepal, the government (as the Grantor) issues licenses to hydropower developers, regulating the services to be provided (electricity sales), the recipient (NEA), and the pricing mechanism (PPA)

2. the grantor controls (through ownership, beneficial entitlement or otherwise) any significant residual interest in the infrastructure at the end of the term of the arrangement.
I*n Nepal's case, hydropower projects are handed over to the Government of Nepal after 35 years, meaning the government retains significant residual interest at the end of the arrangement term.*

The IFRIC 12: Service Concession Agreement applies to Hydropower Entities that meet the above two conditions.

Accounting Treatment under IFRIC 12

As per IFRIC 12, hydropower companies are treated as project contractors rather than owners. The infrastructure is considered to be owned by the Government of Nepal (the Grantor). As a result, the project assets are classified as intangible assets rather than property, plant, and equipment (PPE), and are subsequently amortized.

During the construction phase, hydropower developers account for the project as contractors. Revenue (including any developer's premium or margin) is recognized on a percentage-of-completion basis, in line with construction contract accounting under NFRS15.

Project costs incurred are recognized in the period in which they occur. The resulting difference—i.e., the contract profit—is capitalized as part of the intangible asset.

Conclusion

Nepal's hydroelectric sector is at once highly successful and beset with challenges. It has grown rapidly from less than 1 GW a decade ago to over 3.3 GW today, driven by a combination of policy reforms and private investment. Hydropower now underpins 90%+ of the country's electricity and remains its cheapest power source. However, the sector's future depends on addressing key technical and institutional issues. Projects must balance cost control with robust design (especially hydrology), and financiers must find ways to reduce the very high capital costs. Governments and regulators need to adapt pricing and approval processes to reality: more flexible PPAs, transparent tariff escalation, and faster licensing can improve bankability.

Moreover, broad energy market forces are changing: seasonal surplus, limited export routes, and shifting demand patterns mean that simply building more run-of-river projects may not always add value unless integrated into a wider grid and market strategy. The ideal path likely involves a mix of RoR and some strategically located reservoir projects, along with better demand forecasting and regional trade.

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