Private Sector Participation in Transmission: Blueprint for Reform

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Chapter 1: Preliminary

Chapter Summary

- Nepal has made commendable progress in expanding electricity generation, transitioning from an energy-deficient country to one with surplus generation capacity during the wet season. However, this progress remains underutilised, as the expansion of transmission infrastructure has not kept pace.
- Constraints in the grid's capacity to deliver power reliably and equitably across the country is increasingly becoming a bottleneck to unlocking Nepal's full energy potential. This, in turn, is limiting industrial growth, rural electrification, cross-border electricity trade, and swift transition to cleaner energy.
- Against such background, this paper explores how private sector participation (PSP) in electricity transmission system can help mitigate the situation. It seeks to inform policymakers, regulators, development partners, and investors about the opportunities and policy pathways for catalysing private investment in electricity grid.
- The paper offers insight into Nepal's existing transmission landscape, assesses the policy and regulatory environment. It then reviews different PSP models and international experiences and provides actionable recommendations to address Nepal's current challenges.

Nepal has achieved remarkable progress in electricity generation. Over the past two decades, Nepal's installed capacity has grown tenfold from 389 MW in 2000 to 3,602 MW as of March 2025. This growth has enabled near-universal household electrification and opened new avenues for cross-border energy trade. The latter is expected to generate an estimated NPR 330 million annually.

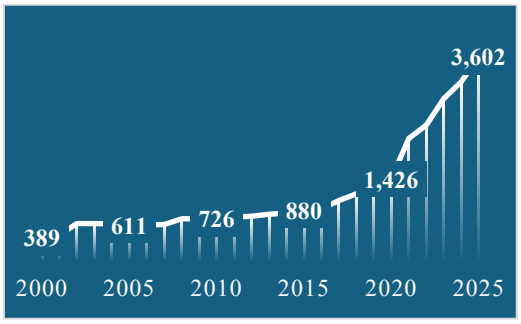


Figure 1: Total Electricity Generation Capacity, Nepal, 2000-2025, (MW)
Source: Nepal Electricity Authority, 2025

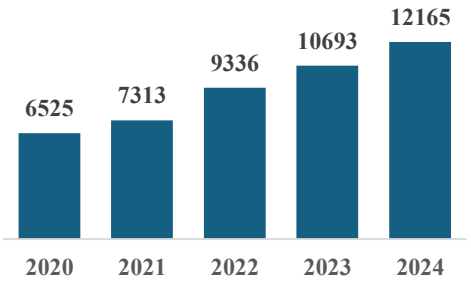


Figure 2: Total Electricity Consumption, Nepal, 2020-2025, (GWh)
Source: Nepal Electricity Authority, 2025

Transmission infrastructure has also expanded significantly over the past decade. Compared to 2015, the total length of transmission lines has increased by 148 percent, averaging an annual growth rate of approximately 11 percent. According to the NEA (2024), Nepal's national transmission network currently spans 6,508 circuit kilometres. Of this, 64 percent comprises 132 kV lines, which continue to form the backbone of the country's transmission infrastructure. An additional 2,281 circuit kilometres of transmission lines are under construction. Upon completion, the total transmission network is expected to reach 8,789 circuit kilometres, with 5,384 km at 132 kV, 1,796 km at 220 kV, and 1,094 km at 440 kV (NEA, 2024), indicating a strategic pivot towards higher-capacity lines.

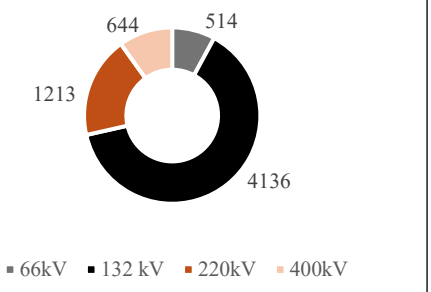


Figure 3: Existing Transmission Lines in Nepal, 2024 (Kilometres)
Source: Nepal Electricity Authority, 2024

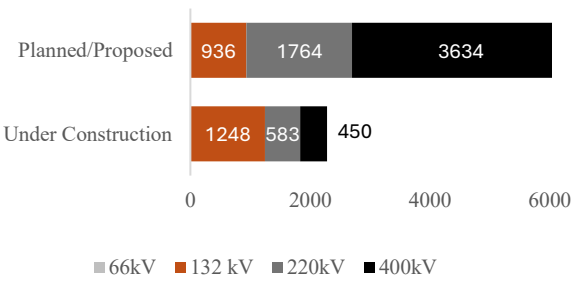


Figure 4: Planned and Under Construction Transmission Lines, Nepal, 2024 (Kilometres)
Source: Nepal Electricity Authority, 2024

But persistent challenges undermine this progress. Nepal continues to lose significant amounts of generated electricity due to inadequate transmission and distribution (T&D) infrastructure. In 2023, IPPAN reported that transmission line shortages led to energy spillage worth NPR 2.8 billion across 20 projects, undermining the commercial viability of hydropower plants.

Beyond financial losses, the mismatch between electricity generation and available T&D infrastructure constrains industrial productivity. The industrial sector consumes over 20% of total energy. Inadequate supply thus has a direct bearing on outputs. With electricity consumption increasing rapidly—from 6,525 GWh in 2020 to 12,165 GWh in 2024—this problem is expected to worsen (NEA, 2024). Inadequate electricity supply can also hinder the achievement of Nepal's clean energy transition goals and the global commitments made within the Nationally Determined Contributions (NDCs).

Nepal's transmission infrastructure also falls short of national needs and policy targets. Nepal's existing transmission grid cannot evacuate the rapidly increasing electricity supply, especially during peak load periods, constraining both system efficiency and access. This shortfall is becoming increasingly critical as hydropower generation surges. Without proportional investments in transmission infrastructure, a growing share of electricity will remain stranded. In 2023 alone, electricity worth NPR 2.8 billion was wasted across 20 projects with a combined capacity of 339 MW, primarily due to insufficient transmission lines and substation capacity (IPPAN, 2023). The loss could potentially hinder Nepal's accelerated efforts to meet its Nationally Determined Contribution (NDC) target of generating 28,500 MW and reaching per-capita consumption of 700 kWh by 2035.

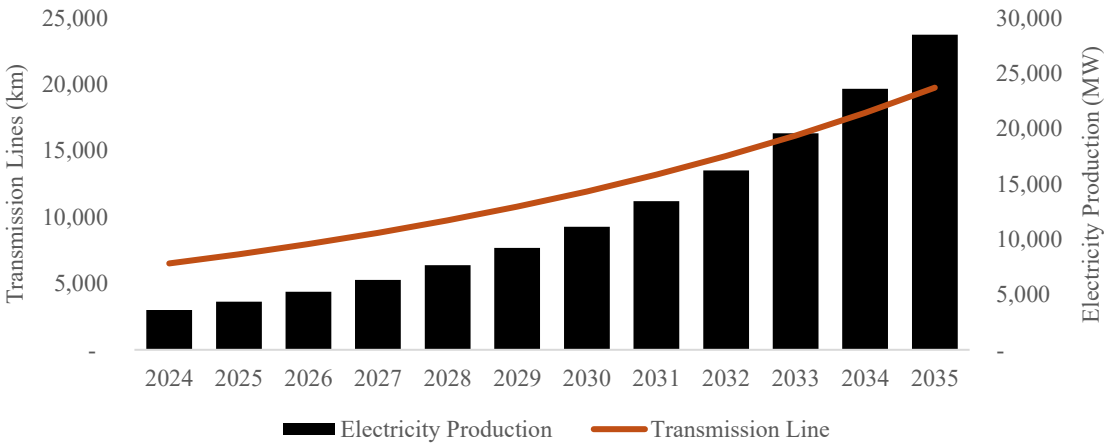


Figure 5: Projected Increase in Transmission Line vs Electricity Generation

Source: Author's calculation[1]

The government recognises the challenges and has even made policy commitments, but its effectiveness remains limited. Under the 15th Periodic Plan (2020–2024), it set a goal of expanding the transmission network to 8,000 circuit kilometres for 66 kV and above, and 7,300 circuit kilometres for 33 kV lines—a combined target of 15,300 km, more than double the then stock of transmission lines (NPC, 2020). However, meeting this target would have required the network to grow at an average annual rate of 31% from 2020 onward. In contrast, Nepal's

[1] The projection assumes Nepal meets its 2035 electricity generation target while transmission infrastructure continues to expand by 11 percent p.a. While not fully precise, this scenario illustrates the implications of maintaining the existing pace of transmission development.

transmission infrastructure has been expanding at a modest average yearly rate of 11%, which, if continued, would only achieve the 15,300 km target by 2033–a full decade behind schedule. Meanwhile, to meet the 2035 NDC target, electricity generation must grow by 21% annually. This will create a widening infrastructure gap that demands urgent corrective action. The development of transmission infrastructure has been undermined by systemic issues like inadequate financing and logistical hurdles (Kremer, 2024).

Land acquisition and securing the Right-of-Way remain among the most entrenched challenges in Nepal's transmission sector. Given Nepal's fragmented landholding patterns and the extensive reach of grid corridors across private, forested, and conservation lands, developers face prolonged delays, community resistance, and legal disputes. One key structural issue is the compensation framework, which typically only covers land directly under transmission towers – often at 10–20% of market value for the full RoW corridor. Although the land beneath transmission lines remains technically usable for farming, its market value plummets, and building restrictions limit its future use. As a result, landowners are unwilling to cede access, leading to escalating protests and litigation.

Implementation delays are exacerbated by poor sequencing: transmission projects often begin before securing land or forest clearance, or without completing Environmental Impact Assessments (EIAs), triggering legal and logistical backlash (Shrestha, 2023). In 2022, the World Bank withdrew from two large transmission projects – 400kV Hetauda–Dhalkebar–Inaruwa and 220kV Hetauda–Bharatpur–Bardaghat – after repeated delays caused by unresolved land and RoW disputes, despite multiple deadline extensions (Shrestha, 2022). The issue reached the judiciary in 2023 when Nepal's Supreme Court ruled that compensation must include not only tower-affected areas but the full RoW corridor – considering displacement risks, health concerns, and capacity ratings. Yet, enforcement remains patchy. Protests by affected communities, such as those in the Arun-3 transmission corridor, have continued despite government and district-level reassessments (Ghimire, 2024).

An added constraint is also the prevailing procurement regime. The Public Procurement Act 2007, while aiming to promote transparency and competition, has instead fostered procedural rigidity and risk aversion within public institutions (Rijal, Khatiwada & Giri, 2014). Discretionary decision-making for project heads is capped, making even routine procurement a bureaucratic bottleneck. Furthermore, the Act's "lowest bid wins" spirit has often resulted in contracts being awarded to firms submitting unrealistically low bids, only to inflate costs post-award or delay execution altogether (Rijal, Khatiwada & Giri, 2014). Such practices erode both cost-efficiency and timely delivery.

These inefficiencies are compounded by a lack of integrated planning across agencies. Coordination failures between the Department of Electricity Development (DoED), NEA, local governments, and forest and land ministries frequently lead to mismatched timelines, stalled

clearances, and cost escalations. News stories of hydroelectricity projects facing major delays due to the absence of a viable transmission line despite having completed generation infrastructure are not uncommon in Nepal. Such stories underscore planning disconnects. Moreover, NEA's practical monopoly over grid development has stifled innovation and private sector participation. Only limited progress has been made despite policy visions for PPP, due to the absence of clear regulatory frameworks on ownership rights, wheeling charges, and tariffs.

Even if these structural issues were fixed, the financing gap is humongous mobilising investment under the current modality is not possible. Nepal's transmission infrastructure has historically depended on the capital expenditure of the Nepal Electricity Authority (NEA), primarily financed through government equity, concessional loans, and multilateral grants. Between 2010 and 2017 alone, an estimated USD 1.4 billion was directed toward transmission and distribution (T&D), mostly from bilateral and multilateral sources (World Bank, 2019). While the Government of Nepal has initiated alternative financing approaches, including joint ventures with foreign utilities such as the Power Grid Corporation of India (PGCI) for cross-border lines like Inaruwa - Purnia and Dodhara - Lamki, these remain limited in both number and scale (Giri, 2025). Emerging Public-Private Partnership (PPP) models, such as the Tamor - Dhungesaanghu 200 kV project between RPGCL and domestic Independent Power Producers (IPPs), offer new avenues for mobilising domestic capital (Oli, 2024). However, such initiatives are yet to match the magnitude of investment required. NEA estimates that NPR 400 billion will be needed for transmission development by 2030 – equivalent to NPR 57 billion per year. This dwarfs NEA's current average annual capital investment of NPR 40 - 50 billion across generation, transmission and distribution, revealing a severe financing shortfall (Shrestha, 2022).

Table 1: Zone-wise Transmission Infrastructure Development Plan and Financial Requirement

Zones	Details	Gridline (km)	Cost (USD million)
1	Mahakali, West Seti, and Karnali corridors	1162	688
2	Bheri corridor	859	480
3	Kali Gandaki and Marsyangdi corridors	1879	935
4	Trishuli-Chilime, Khimti, and Tamakoshi corridors	1418	807
5	Koshi, Arun, and Kabeli corridors	1547	857
		Total	3768

Source: Rastriya Prasaran Grid Company Limited, 2018

Chapter 2: Private Sector Transmission

Chapter Summary

- PSP in transmission infrastructure can facilitate development by bridging financing gaps, managing risks more effectively, and improving service quality through private sector efficiency, innovation, and accountability.
- Some modalities of PSP include service contract, management contract, lease contract, concession contract, joint venture, divestiture, and merchant line.
- Given the current political, social, and economic situation, Nepal should adopt concession-based models, especially variations of Build-Operate-Transfer (BOT) or Build-Own-Operate-Transfer (BOOT), or joint venture to attract private sector in transmission infrastructure development.
- Concession contracts ensures that the government retains the ownership of the asset in the long-run, while transferring financial and operational risk to the private sector.
- Countries like Brazil, India, Peru, and Turkey are some examples of where concession contracts have been implemented successfully.

Governments worldwide are increasingly leveraging PSP models to strengthen electricity transmission networks. PSP in electricity transmission refers to the involvement of private actors in financing, constructing, operating, or maintaining power infrastructure. In this context, PSP does not necessarily mean privatisation. Rather, it encompasses a spectrum of arrangements, from short-term service contracts to long-term PPPs, concessions, and, in some cases, full private ownership under regulatory oversight.

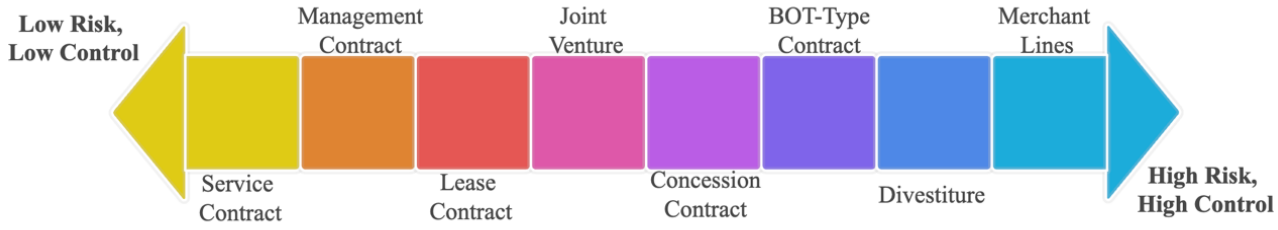
Electricity T&D are capital-intensive sectors that exhibit the characteristics of natural monopolies i.e. high fixed costs and economies of scale make it more efficient for a single provider to operate the network. Furthermore, as electricity T&D is an essential service and one that holds strategic importance for economic and social development, these systems have been historically developed, managed and owned by the state in most countries. However, today, 75 percent of the money spent on building and maintaining energy systems around the world comes from private, profit-driven institutions (IEA, 2024). Governments finance merely 30 percent of transmission projects and 20 percent of distribution projects.

Box Case: Reasons for shift to Private Sector Participation

1. **Bridging the Financing Gap**: Upgrading and expanding T&D infrastructure require enormous capital investment, often far beyond what public budgets alone can accommodate. PSP allows governments to tap into private capital and unlock new sources of investment, reducing the burden on public finances while accelerating infrastructure development.
2. **Sharing and Managing Risk**: Electricity networks are subject to a range of complex risks – from construction delays and cost overruns to fluctuating demand and political interference. By bringing in private partners through well-designed contracts, governments can shift certain risks to actors better equipped to manage them.
3. **Improving Service Quality**: In many countries, state-run electricity utilities suffer from chronic service quality issues such as frequent outages, voltage fluctuations, poor customer service, and most critically, high system losses. These losses are either technical losses, caused by aging infrastructure, overloaded transformers, and inefficient grid design, or commercial losses, driven by electricity theft, faulty metering, and weak billing and collection mechanisms. Private sector participation can help address these challenges by introducing better management practices, modern technology, and performance-linked incentives. For example, private operators may invest in smart meters, automate billing, or upgrade substations and lines to reduce losses.
4. **Driving Efficiency and Innovation**: Market-based incentives can push private operators to find cost-effective solutions and invest in innovation. Whether through smart grid technologies, real-time monitoring systems, or advanced metering infrastructure, private firms often introduce operational efficiencies that are difficult to replicate in traditional bureaucratic systems.

PSP in electricity transmission encompasses diverse models. Each PSP model implies varying levels of responsibility and risk to be assumed by the private operator, together with differences in structures and contract forms.

Selected PSP Models based on Private Sector Risk and Control



1. Service Contract

A service contract is a short-term agreement—typically 1 to 3 years—where the private sector is hired to perform specific tasks such as billing, maintenance, or leak detection. The government retains full control and responsibility for assets and investment. The contractor is paid a fixed fee and operates under clear performance targets, without contact with end users. This model suits early reforms but does not attract private investment or address infrastructure gaps.

2. Management Contract

A management contract delegates operational responsibility to a private firm while the government retains asset ownership and capital investment roles. The private operator may contribute working capital and is paid through fixed and performance-based fees. This model improves operational efficiency but offers limited private risk-sharing and does not mobilise infrastructure financing.

3. Lease Contract

In a lease contract, the private party assumes operational and commercial risks over a 10–20 year term, collecting revenue directly from users and paying lease fees to the government. The state retains ownership and responsibility for major capital works. Lease models are useful when public infrastructure exists but lacks efficient operations. However, they provide limited incentives for long-term asset upkeep and do not attract private capital.

4. Concession Contract

A concession gives the private operator full responsibility for financing, operating, maintaining, and expanding infrastructure over a long-term period (usually 25–30 years). Revenues come from user tariffs, while the assets remain publicly owned. The government acts as a regulator, monitoring service quality and tariff compliance. Concessions suit infrastructure-heavy sectors

but require strong regulation and well-designed contracts to manage risks of monopoly, complexity, or renegotiation.

5. BOT-Type Contract

Build-Operate-Transfer (BOT) models are project-specific PPPs in which the private party designs, finances, constructs, and operates new infrastructure for a set period, recovering investments through user fees or availability payments. Variants include BOOT (ownership during contract), BOO (permanent ownership), and DBFO (design-build-finance-operate). After the term ends, ownership typically reverts to the state. These models help develop large-scale infrastructure where public funding is limited but involve high debt and complex procurement.

6. Joint Venture

In a joint venture, public and private entities co-own and operate a utility or infrastructure company, often via shareholding and a joint board. The private sector typically leads operations, while both sides co-invest and oversee governance. JVs are well-suited for politically sensitive sectors or markets transitioning from public to mixed ownership. They foster collaboration but require strong safeguards to manage conflicts of interest and ensure independence from political interference.

7. Divestiture

Divestiture involves the full or partial sale of public infrastructure to private ownership through asset sales or equity offerings. The private operator assumes full responsibility for financing, operations, and risks, while the government typically exits from service delivery. Divestiture works best in mature markets with strong regulation and investor interest but requires transparent processes and public communication to avoid backlash, especially for essential services.

8. Merchant Lines

Merchant lines are privately financed transmission projects developed without government guarantees or regulated revenue. Developers earn returns through market-based tariffs from willing buyers—such as generators or traders—under open access regimes. While they offer speed and innovation in competitive markets, they are highly risky and unsuited to immature markets with weak price signals or grid access uncertainty.

Table 2: Private Sector Participation Models

PPP Option	Key Features	Private Sector Role & Risk	Government Role	Best Suited Context	Potential Challenges
Service Contract	Short-term (1–3 years); private performs specific operational tasks (e.g., billing, maintenance).	Paid fixed fee; no capital investment; low risk; no direct user contact.	Retains control & investment; sets tariffs and assets.	Early-stage reforms; improve efficiency without transferring control.	Limited private investment; narrow impact; assets & tariffs politically sensitive.
Management Contract	Private manages day-to-day operations; government retains ownership and major capital responsibility.	Assumes operational control; may provide working capital; no major investment risk.	Ownership & capital investment; tariff setting.	When improved operational efficiency is needed without investment transfer.	Limited control limits long-term impact; possible misaligned incentives; risk of underinvestment.
Lease Contract	Private operates and manages service (10–20 years); government owns assets and invests capital.	Full operational risk & cost; collects revenue; pays lease fees.	Owns infrastructure; responsible for major capital.	Existing infrastructure needing efficient operation; private takes operational risk without investment.	No private capital investment; tariff dependence sensitive; risk of under-maintenance near contract end.
Concession Contract	Long-term (25–30 years); private operates, maintains, finances, expands infrastructure.	Full operational and investment risk; collects tariffs; profits linked to efficiency.	Regulates service standards, tariffs; owns assets.	Infrastructure-heavy sectors needing long-term investment & cost recovery (water, energy, transport).	Complex contracts; political sensitivity; risks of monopoly; contract duration complicates investment timing.
BOT-Type Contract	Private builds, operates, finances new infrastructure;	High financial & operational risk; recovers investment via user fees or govt. payments.	Regulator and eventual owner; may guarantee payments.	Large-scale capital-intensive projects with limited public	Project-specific impact; high private debt cost; limited competition after

PPP Option	Key Features	Private Sector Role & Risk	Government Role	Best Suited Context	Potential Challenges
	ownership returns to government at end.			funds and predictable demand.	bidding; contracts often renegotiated.
Joint Venture	Shared ownership and operation by public and private sectors; co-investment and governance.	Invests capital; shares risk; manages operations; motivated for success.	Co-owner and regulator; dual role may cause conflicts.	Politically sensitive sectors; gradual liberalisation; where public ownership and private efficiency mix needed.	Potential conflicts of interest; informal procurement risks corruption; requires strong governance.
Divestiture	Full or partial transfer of public infrastructure or services to private ownership through sale, equity offerings, or strategic placements.	Full control, investment, and operational responsibility; bears all risks; earns return via tariffs or profits.	Regulatory oversight only; no operational or ownership role in full divestiture.	Mature markets with strong regulatory institutions; services needing efficiency improvements; governments seeking to reduce fiscal burdens.	Public resistance; risk of reduced affordability; requires strong regulator, transparent asset valuation and sale, and safeguards for public interest.
Merchant Lines	Privately financed and operated transmission projects; revenue based on market-based tariffs with no government guarantee or regulated returns.	Assumes full market, demand, and counterparty risk; invests and earns from users via negotiated or spot-market tariffs.	Provides grid access, legal rights-of-way, and general market regulation; no direct payment or concession.	Competitive electricity markets with generation surpluses; cross-border interconnectors; regions with clear demand and pricing signals.	High market risk; dependent on pricing transparency and strong legal frameworks; limited applicability in regulated or immature power markets.

Source: Adapted from: Asian Development Bank (ADB), "Public–Private Partnership (PPP) Handbook," 2008. Additional analysis and interpretation by the author.

Nepal should consider adopting concession-based models as viable forms of PSP in transmission infrastructure. It is important to recognise that no single PSP model is universally applicable. The appropriateness of each approach depends on a country's unique context, including the core objective (e.g., financing versus service delivery), institutional capacity, political economy considerations, and risk allocation preferences. The success of PSP hinges on selecting a model that aligns with national priorities and institutional realities - only then can private capital and technical expertise be mobilised effectively without undermining public accountability.In Nepal's current context, the most binding constraint is a chronic financing gap. The transmission sector alone requires an average of NPR 57 billion annually to meet its expansion targets. This amount is unlikely to be mobilised through public finance, given Nepal's limited fiscal capacity and competing development priorities. This makes private sector investment essential rather than PSP models such as service contracts or management contracts that are focused solely on operational improvements; these may enhance efficiency, but do not unlock the capital required for large-scale infrastructure expansion.

At the other end of the spectrum, high-control models like Build-Own-Operate (BOO), Divestiture, and Merchant Lines allow full private ownership and greater pricing autonomy. While these models might work in liberalised markets, they pose significant risks in Nepal's political and regulatory environment. First, they would require major reforms and regulatory oversight. However, the repeated failure to pass the long-awaited Electricity Bill signals limited political appetite for radical changes. Second, these models may be politically contentious and publicly unpopular for it is easy to frame reforms as privatising national assets in Nepal. Premature moves toward full privatisation may trigger public resistance, delay implementation, and jeopardise investor confidence.

A more pragmatic and politically feasible pathway is the adoption of special variants of concession-based models**, such as Build-Operate-Transfer (BOT) or Build-Own-Operate-Transfer (BOOT) arrangements.** These models allow the private sector to finance, construct, and operate transmission assets for a fixed period, after which ownership reverts to the state. They enable Nepal to crowd in private investment while maintaining strategic control over infrastructure and setting the stage for gradual, confidence-building reforms. Concession models also offer a middle ground that can secure broader political consensus and public acceptance which are key ingredients for durable reform in Nepal's evolving federal system. Additionally, joint venture models**,** where public and private actors co-invest and co-govern transmission entities, can complement concessions by aligning interests, sharing risks, and creating accountability through shared ownership. This is particularly relevant for politically sensitive or cross-border projects, where both legitimacy and efficiency are essential.

Table 3 below highlights international case studies that illustrate how countries have advanced PSP in transmission through tailored reforms and model selection.

Table 3: Lessons from Countries that Successfully Adopted PSP in Transmission Infrastructure

Note: Detailed explanation of the cases are provided in the relevant recommendation sections.

Themes	Brazil	Peru	Turkey	India
Ex-Ante conditions prior to unbundling reforms	Strong government participation across the energy value chain; power generation utilities are responsible for developing and operating transmission gridlines, with the final cost embedded in the power sold to the distributors	Similar vertical concentration; private sector excluded until reforms	Similar to Nepal's NEA, TEK was established to oversee the energy value chain. Prior to TEK's establishment the energy ecosystem of Turkey encouraged private sector participation but a one-off nationalisation in the electricity sector in the late 1930s significantly limited private sector participation.	Similar to Turkey; nationalisation in the Electricity sector post-independence and the creation of State Electricity Boards in each state to govern all aspects of energy value chain within a given state.
Reform Initiatives	Law Nº9074 (1995) unbundled the electricity sector, enabled private sector participation in transmission and distribution, broke up vertically integrated utilities, and enabled determination of tariff and wheeling charges based on market principles	Law for Power Concession (LCE, 1993) prevented vertical concentration of ownership across the energy value chain, ; anti-trust law (1997) further strengthened the unbundled regime.	Unbundling of TEK in 1993 into TEAS and TEDAS; further unbundling in 2001 created EUAS, TEIAS, TETAS	Electricity Act, 2003 mandated unbundling of SEBs into generation, transmission, and distribution entities
Private Sector Entry Modalities	Law Nº9074 governs the modality of private sector participation; private sector participation ensured through Permitted Annual Revenue approach, i.e., concessionaires are guaranteed a	Law of Power Concession provisions for competitive bidding process, Concession regime follows BOOT model (30-year concession)	Private sector ownership of Assets not allowed; instead of revenue guarantee profit guarantee model used for determining the concessionaire. Concession	BOOM and DBFOT models; Viability Gap Funding for DBFOT; private asset ownership allowed under MoP model

Themes	Brazil	Peru	Turkey	India
	minimum annual revenue based on the amount quoted in the winning bid but are not allowed to keep excess revenue		agreement follows BOT & TOOR model only.	
Tariff Structure & Reforms	Transition from welfare tariffs to market-based pricing; abolished CRC; introduced cost-reflective tariffs via Resende Act	Initially cost-recovery-based tariffs; later fixed efficient cost method adopted post-2006 to improve certainty and reduce volatility	Full cost-reflection pricing; CPI-based adjustments; regulated by EMRA; standardised national tariffs via Price Equalisation Mechanism	Tariff-based competitive bidding; project-specific transmission tariff determined through competitive bidding
Ownership of T&D Infrastructure	Private ownership allowed under regulated regime	Private ownership allowed; regulated by COES & OSINERGMIN	Transmission: State-owned (TEIAS); Distribution: operational rights privatised, ownership retained by TEDAS	Both public and private ownership models; BOOM model allows indefinite private ownership
Risk Allocation	Market risks mitigated via revenue caps; no guaranteed profit	Full project risk borne by concessionaires; State liable only if unjustified termination	Market risk initially borne by TEAS; later shifted to private sector; redetermination allowed if demand dropped significantly	Project risk fully borne by concessionaires; revenue through transmission tariffs; some counter-guarantees available under fast-track
Institutions Involved	ANEEL (regulator), EPE (planning), MME (policy), ONS (system operator)	MINEM (policy), CEPRI (privatisation), OSINERGMIN (regulator), COES (system operator)	MENR (policy), TEIAS (transmission operator), EMRA (regulator), TEDAS (distribution owner)	MoP (policy), Central & State Commissions (regulation), SEBs (former utilities), Planning Commission (project modality developer)

Chapter 3: Key Reforms to enable Private Sector Transmission

Chapter Summary

- To successfully adopt a concession model, Nepal must implement regulatory reforms that create clear incentives and balanced risk-sharing for private investors. Without a well-designed PSP structure, risk allocation may be poorly calibrated, leading to delays or reluctance from private investors to enter the transmission and distribution sector. For example, if private operators are made responsible of financial risk in a politically sensitive environment without the unbundling of the NEA or guaranteed tariff frameworks, they may either withhold investment or underinvest, undermining project viability.
- Some of the major reform requirements to attract private sector include unbundling the NEA, improving tariff and wheeling charge determination structure and making it predictable, making clear frameworks for competitive bidding, ensuring open access of transmission grid, introducing financial or regulatory incentive for PSP, and resolving issues related to land acquisition and RoW.

1. A major obstacle to private sector participation in Nepal's transmission infrastructure is the enduring monopoly of the NEA. While Nepal's power generation sector has seen increasing private investment due to clearer entry pathways, the same has not materialised for T&D. This is primarily because NEA remains a vertically integrated utility – simultaneously acting as generator, grid operator (transmission), and sole off-taker (distribution) – creating serious conflicts of interest and deterring independent investment.

What this means for private developers is that even though the Electricity Act 1992 does not bar private developers from entering into any sector within hydropower development, they face multiple practical challenges. NEA, for instance, may give preferential treatment to its own projects: in 2022 NEA did not purchase electricity produced by private power producers, citing transmission system overload, leading to private sector loss of NPR 1 billion (New Business Age, 2022).

Although Nepal's Hydropower Development Policy (2001) and a proposed amendment to the Electricity Act (2007) envisioned unbundling NEA, reforms stalled due to political resistance and strong opposition from NEA's employee union. The establishment of the RPGCL in 2015 to lead transmission development was also undermined, with NEA leadership resisting functional transfer. As a result, RPGCL has remained largely symbolic, managing only minor projects while NEA continues to dominate transmission. NEA's political ties and past resistance to reform shows its desire to maintain excessive control, further eroding investor confidence.

Recommendation 1: Unbundling the NEA for Effective Energy Sector Reform

Recommendation 1.1: Accelerate Unbundling Process of NEA

Unbundling refers to the separation of a vertically integrated utility into distinct entities responsible for generation, transmission, and distribution. The goal is to eliminate conflicts of interest, introduce competition where possible, and ensure transparent and non-discriminatory access to infrastructure such as the national grid.

The draft Electricity Bill (2023) represents a potential to implement the much-needed reform as it includes a legal mandate that no single entity may operate across all three functions. It requires existing vertically integrated utilities to unbundle within five years of the law's enactment. That said, both the existing law and the draft (Electricity Bill, 2023) fall short when it comes to reducing the government's direct involvement across the entire electricity system. For example, they make no mention of breaking up the Nepal Electricity Authority (NEA), which currently runs generation, transmssion, and distribution directorates simultaneously under one roof. Without addressing this core issue, real reform of the sector will remain limited.

The policymakers must act decisively to implement unbundling, ensuring that the Bill endorses into an Act in the 2025 parliamentary session itself, opening avenues for PSP in transmission infrastructure.

Recommendation 1.2: Clarify Institutional Mandates in the Electricity Bill

The bill introduces measures to unbundle the energy value chain, particularly by assigning the responsibility of developing and managing transmission infrastructure to the RPGCL. However, important ambiguities and institutional overlaps remain.

Currently, NEA's Transmission Directorate discharges many of the same functions that the RPGCL is expected to undertake. The bill does not clarify whether the Transmission Directorate will be transferred to RPGCL, dissolved entirely, or allowed to operate in parallel.

This lack of clarity risks operational confusion, weakens accountability, and may delay or dilute the unbundling process. Meanwhile the coexistence of NEA's Transmission Directorate and RPGCL could lead to a duplication of roles in the development and operation of transmission infrastructure. Such duplication is administratively inefficient, financially burdensome, and counterproductive to the goal of unbundling.

Box Case 1: Turkey's Experience: Unbundling the Electricity Authority

Turkey's electricity sector began with a fragmented structure where different players owned and operated different parts of the energy value chain (Budak, 2012). But as energy demand grew and the need for a unified national system became clear, the government moved towards centralisation. This led to the formation of the Turkish Electricity Authority (TEK) - a state-owned monopoly similar to Nepal's NEA - that brought together generation, transmission, and distribution under one roof. TEK played a crucial role in creating an interconnected national transmission network, but over time, the inefficiencies of a vertically integrated monopoly became apparent.

To address these issues, Turkey initiated a major reform in 1993, breaking up TEK into separate entities. This process led to the formation of Turkish Electricity Generation and Transmission Company (TEAS) and Turkish Electricity Distribution Company (TEDAS). Later, in 2001, TEAS itself was unbundled into three distinct state-owned companies:

i. Electricity Generation Company (EUAS)
ii. Turkish Electricity Trading and Contracting Company (TETAS)
iii. Turkish Electricity Transmission Company (TEIAS)

TEIAS was given full responsibility for the ownership, operation, maintenance, and expansion of the national transmission grid. Rather than further dividing transmission responsibilities, Turkey chose to keep all core transmission functions integrated within TEIAS to maintain system reliability and investment coordination. While private sector participation was allowed through models like Build-Operate-Transfer (BOT), the core planning and control functions remained with the public entity. This structure ensured that both present reliability and future accessibility of electricity could be managed coherently. Turkey's experience demonstrates that unbundling is about creating clarity and efficiency by assigning specific roles to well-defined institutions.

The bill should clearly outline a transition plan for transferring all relevant responsibilities and assets from NEA's Transmission Directorate to RPGCL to avoid overlapping mandates and ensure a smooth, coordinated shift.

2. Private investment in transmission is further held back by the absence of a predictable, cost-reflective tariff and wheeling charge framework

The Electricity Act (1992) and subsequent ERC Act (2017) lay the foundation for tariff regulation. As per Clause 13(1E) of the ERC Act, the ERC is authorised to determine wheeling charges for the use of transmission and distribution infrastructure. The criteria prescribed in Rule 13 of the ERC Rules, 2018 focuses primarily on basic technical parameters such as load and distance of electricity transfer, point of connection, zonal transmission costs, and infrastructure investment for expansion.

These criteria do not account for key commercial and financial considerations such as operation and maintenance costs, loan repayment obligations, return on equity, infrastructure depreciation, inflation, and revenue requirements.

The omission of these cost-recovery fundamentals in wheeling charges determination leaves private developers exposed to unpredictable and potentially insufficient revenues, deterring investment in long-term, capital-intensive transmission projects. Compounding this issue is the cost-recovery deficit in the transmission sector. According to NEA's annual reports, the utility suffers financial losses due in part to high power purchase costs, technical and commercial losses, and a tariff structure that does not reflect the full cost of service.

Clause 18(2) of the ERC Act allows off-grid concessionaires - those operating independently from the national grid - to set their own electricity tariffs. These tariffs are legally permitted to cover full cost recovery over 25 years, and a 25 percent return on equity investment. This provision ensures a clear and predictable revenue stream for small-scale, isolated systems.

In contrast, grid-connected transmission investors – who typically engage in large, capital-intensive infrastructure – have no such financial safeguard. The existing legal framework for determining transmission wheeling charges remains vague, fragmented, and silent on cost-recovery guarantees. There is no assurance that private transmission developers will be able to recover their investment or earn a reasonable return through regulated tariffs.

This lack of tariff clarity and revenue predictability significantly raises financial risk for private developers. Without reforms to introduce structured cost-recovery mechanisms, or guaranteed minimum payments, the private sector is unlikely to participate in transmission infrastructure development.

Recommendation 2: Improving Tariff Determination for Predictable Cost Recovery

Recommendation 2.1: Expand the factors used to determine transmission tariffs

The ERC Rules (2018), Rule 9 outlines different factors considered for setting end-consumer tariffs of electricity. These include essential variables such as:

- Operating and maintenance costs

- Investment capital and cost recovery
- Consumer Price Index (CPI) to reflect inflation
- Expected return on equity
- Revenue requirement and financial sustainability

These criteria are not considered while determining wheeling charges. Likewise, the Rules also do not consider sunk costs – past investments that continue to influence the value and use of infrastructure – in the calculation of tariffs. However, international examples, including Brazil and Turkey, show that including sunk costs is crucial to ensure the "full reflection of efficient cost" in pricing decisions. Recognising sunk costs prevents under-pricing that could disincentivise long-term investment in electricity infrastructure.

The ERC Act should expand the scope of criteria considered to determine wheeling charges and incorporate additional criteria - like Rule 9 of the ERC Rules and sunk costs - to make the transmission tariffs cost-reflective.

Recommendation 2.2: Extend competition-based tariff-setting principles across the energy value chain

While the ERC Rules, 2018 provide some scope for negotiated and competitive tariff determination, particularly in Rules 8, 10, and 14, these provisions currently apply primarily to generation and consumer pricing. These include

- Rule 8 allows customer service concessionaires to submit their own tariff proposals.
- Rule 10 enables energy purchase rates to be negotiated between generation concessionaires and buyers.
- Rule 14 promotes competition in setting end-consumer tariffs.
- Rule 19 mandates public hearings for all types of tariff decisions.

Incorporating these in transmission system would enable market negotiation, competitive bidding, and stakeholder participation in tariff setting, promoting efficiency, accountability, and private sector confidence.

The ERC Rule, 2018 should expand the application of Rules 8, 10, 14, and 19 to transmission infrastructure.

Box Case 2: Peru's Journey to a Competitive and Cost-Reflective Tariff Regime for Transmission

Peru began liberalising its electricity sector in the early 1990s with the First-Generation Reform (1992–1993), backed by the Law of Electrical Concessions (LCE) (Crousillat, 2012). This law allowed private investors to enter the T&D segments under long-term concessions. Concessionaires were obligated to offer non-discriminatory third-party access to the T&D network, while the State committed to compensate them if concessions were terminated without due cause.

The initial tariff framework intended to allow investors to recover "efficient costs." In theory, "efficient cost recovery" meant allowing investors to recover all reasonable costs of building and operating transmission assets. However, in practice, the tariff calculations omitted key components. For example, the costs that had already been sunk into existing infrastructure not adequately accounted for. This meant that private concessionaires could not recover the value of infrastructure they had acquired, making the deals less attractive. Additionally, the methodology used to determine future transmission needs and asset values relied on overly optimistic or inaccurate forecasts of electricity demand and grid usage.

Transmission tariffs were recalculated every few years, and each round often produced inconsistent and sometimes sharply differing results, creating uncertainty for investors who needed stable, long-term revenue projections to finance large infrastructure projects. This lack of predictability made it difficult for the government to attract serious private participation in the transmission domain.

In response, Peru launched a Second-Generation Reform in 2006 to stabilise and professionalise the tariff regime. This reform introduced the "fixed economically efficient cost" methodology – a more rigorous and investor-aligned approach to tariff determination. Under this model, tariffs began to reflect the full lifecycle cost of transmission, including:

i. **Sunk Costs**: The new methodology explicitly included the cost of existing infrastructure already purchased by private investors, ensuring they could recover previous investments through future tariff payments.

ii. **Competitive Bidding Costs**: For new transmission infrastructure, the cost basis for tariff setting was no longer theoretical. Instead, it was grounded in the actual results of competitive tenders, reflecting the real-world lowest cost at which infrastructure could be built.

iii. **Least-Cost Valuation**: Tariffs incorporated the concept of "replacement value" - i.e., what it would cost to rebuild the infrastructure using the least-cost.

iv. **Operating Assumptions**: Cost estimates assumed infrastructure would run at around 80% capacity, a reasonable benchmark for efficient usage while accommodating future demand. Additionally, operation and maintenance costs were systematically integrated.

v. **Tariff Stability**: Perhaps most importantly, this new model eliminated arbitrary or fluctuating recalculations, offering more predictable, long-term revenue streams.

By implementing these changes, Peru created a robust foundation for long-term private sector participation in transmission infrastructure.

3. Another barrier is the absence of a transparent and competitive bidding process in the existing law.

The existing Electricity Act of 1992 provides no provision for open, merit-based allocation of concessions for transmission development. Instead, it relies on a direct licensing approach, where private entities apply individually for project approval, often through unsolicited proposals. These licenses are granted through administrative discretion, without competition or performance benchmarking.

This framework undermines predictability, fairness, and investor confidence, while creating space for rent-seeking and inefficient project allocation. In practice, licenses are often used to block competition, with developers acquiring survey or generation licenses simply to hold project rights without progressing them. This form of speculative licensing prevents other capable firms from entering the space, distorts the market, and delays infrastructure development.

In contrast, international best practices, particularly in sectors like electricity transmission, which exhibit natural monopoly characteristics, emphasise competitive procurement. Open bidding ensures value for money, attracts technically capable developers, minimises political interference, and creates a level playing field for both domestic and foreign investors.

Recommendation 3: Institutionalise Competitive Bidding for Transmission Development

Recommendation 3.1: Introduce Competitive Bidding by Reforming Electricity Act, 1992

The proposed Electricity Bill, 2023 makes a significant improvement by introducing competitive bidding. Under Clause 11, it mentions that the bidders should be evaluated based on technical, financial, and managerial capacity over immediate fiscal gains. This reflects a strategic policy shift towards selecting concessionaires that are capable of delivering reliable, high-quality infrastructure. Global evidence affirms that a concessionaire's technical and execution capacity is the strongest predictor of long-term service quality (Budak, 2012).

Recommendation 3.2: Amend Financial Selection Criteria to Prevent Tariff Inflation

Despite its strengths, the bill currently stipulates that, after technical evaluation, the final award be based on the most financially lucrative offer. This approach may incentivise bidders to overbid, and later pass costs onto consumers through inflated tariffs. Instead, Nepal should adopt tariff-based selection models, as used in Brazil and Peru, where winners are selected based on the lowest expected annual revenue required to operate and recover investment. In Turkey, bids are assessed based on minimum return on investment (ROI) expectations.

Recommendation 3.3: Remove Domestic Bidder Preference to Encourage Competition

The current Electricity Act, as well as the proposed Bill, favour domestic bidders over foreign ones. While intended to promote local participation, such provisions deter foreign investment, particularly in high-capex transmission projects where international firms often bring much-needed capital, technology, and operational experience. The clause should be eliminated or revised to uphold competitive neutrality and attract broader investor participation.

Recommendation 3.4: Enable Divestment of State-Owned Transmission Assets

Nepal's legal framework, including the proposed Electricity Bill 2023, currently lacks provisions for the competitive divestment of state-owned transmission assets. Introducing such a mechanism would allow the government to auction underutilised or non-strategic assets to private players through transparent bidding. This approach can generate government revenue, reduce NEA's operational burden, and improve asset efficiency through private sector stewardship.

4. Establishing an open access regime would significantly enhance private sector participation in Nepal's electricity transmission infrastructure.

Open access refers to the legal right of licensed electricity generators, traders, or suppliers to use the existing transmission and distribution infrastructure – even if it is owned by a single, vertically integrated utility like the NEA – to transmit electricity to consumers or other buyers. Private entities can access the national grid to sell their electricity without having to build their own transmission lines.

Box Case 3: Unbundling and Open Access as Catalysts for Private Investment in Transmission Infrastructure of Brazil

In the early 1990s, Brazil's electricity sector was characterised by vertically integrated state-owned utilities that held bundled concessions - controlling generation, transmission, and distribution under a single entity (Henrique & Filho, 2012). Transmission infrastructure was developed as part of generation projects, with costs embedded in electricity prices and limited transparency. The lack of institutional separation and open access meant that new market entrants had little opportunity to participate in the value chain, stifling efficiency and private investment.

Facing economic stagnation, mounting fiscal constraints, and chronic underinvestment in infrastructure, the Brazilian government enacted Law Nº 9074 in 1995 - a landmark reform that unbundled the sector and established legal provisions for open access to transmission and distribution networks. This law allowed private entities to operate independently in each segment of the energy value chain, effectively dismantling the monopolistic structure that had long limited competition and innovation.

Open access became the cornerstone of Brazil's market liberalisation. Generators and consumers were given the legal right to use existing transmission lines, while transmission service providers were obligated to provide non-discriminatory access. To enable this, Brazil developed a transparent and regulated wheeling charge framework, where tariffs were based on cost-reflective principles. These reforms not only lowered entry barriers but also helped establish transmission as a standalone, investable business model.

The benefits were significant. The Sanchez and Oguah (2015) reported that by 2015, Brazil had attracted over USD 12 billion in private investment for transmission projects. Brazil's transmission capacity expanded rapidly, enabling greater system reliability, inter-regional power flow, and integration of renewable energy sources.

Transparent wheeling charges and independent system operation fostered a more efficient, decentralised, and resilient electricity market.

The existing Electricity Act, 1992 does not contain any provision mandating or facilitating open access to the transmission or distribution networks for third-party energy generators, traders, or customer service providers. By not providing for open access, Nepal's current legal and regulatory framework protects NEA's monopoly over grid access and customer service. This prevents entry of private sector actors as:

- Without open access, private investors cannot be sure that other power producers, traders, or large consumers will be allowed to use their transmission lines. This uncertainty makes the business case for building transmission lines weak or un-bankable, as revenue depends on usage.
- If the grid is controlled by a vertically integrated utility (NEA), and third parties are not legally entitled to access it, then private transmission lines may sit underutilised, or may

need to compete unfairly with state-owned infrastructure. That creates a risk of stranded assets.

- In the absence of open access there is no legal obligation for other market actors to use privately built transmission lines, and no assurance that usage will be sufficient to cover costs or generate returns. Moreover, if wheeling tariffs are not clearly defined or regulated, revenue expectations become highly uncertain. This level of unpredictability makes transmission projects financially unviable for private investors as there is no room to reliably forecast future cash flows, secure project financing, or plan long-term operations.

International experience shows that introducing open access to transmission services is a critical first step toward market liberalisation. It enables efficient use of infrastructure, lowers unit costs through competition, and ensures increased private investment in both generation and grid assets.

Recommendation 4: Guaranteeing Open Access to Create a Competitive Transmission Market

Recommendation 4.1: Enact and Operationalise Legal Provisions for Non-Discriminatory Open Access to Transmission Infrastructure

The proposed Electricity Bill 2023 includes provisions that require both public and private transmission concessionaires to provide open access to their infrastructure. This means that third-party entities involved in generation, trading, or distribution can apply to use existing transmission or distribution lines and must pay a regulated wheeling tariff set by the ERC.

The government should enact the proposed Electricity Bill and ensure its open access provisions are fully operationalised – specifically those requiring transmission concessionaires to allow licensed third-party entities (e.g. generators, traders, or bulk consumers) to use the grid infrastructure on equal terms. The law must also clearly mandate non-discriminatory access, define roles and obligations of the transmission owners, and empower the ERC to monitor compliance and resolve disputes. Without legal enforcement, open access risks remaining a formal provision with little real effect.

5. The existing fiscal and regulatory incentives for private investors in electricity sector remain limited in scope and are inadequate to mobilise large scale capital.

The Electricity Act, 1992 offers financial incentives for concessionaires involved in the development and operation of T&D infrastructure. Clause 12 of the Act provides for a reduced 1% customs duty and exemption from import and sales tax on capital equipment and machinery not available domestically. Likewise, Clause 13 ensures access to foreign exchange at the prevailing market rate for repatriation of profits, returns on equity, and loan repayments involving foreign investment. These incentives are further supported by provisions in the Foreign Investment and Technology Transfer Act (FITTA), 2019, which guarantees repatriation rights and access to foreign exchange. Together, these frameworks offer a basic level of fiscal facilitation for foreign investors and cross-border partnerships.

While these measures are a step in the right direction, they fall short of the broader incentive packages seen in comparable reforming economies. For instance, during India's first-generation power sector reforms (1991–1995), the government introduced a suite of attractive incentives such as five-year income tax holidays. These incentives played a pivotal role in drawing both domestic and foreign investment into India's previously state-dominated energy infrastructure.

Recommendation 5: Expanding Incentives to Attract Private Capital

Recommendation 5.1: Tax incentive

A time-bound (five to seven-year) corporate income tax holiday for private concessionaires developing transmission infrastructure would improve project viability, especially in the early years when cash flow is limited. This has been effective in countries like India and Indonesia to jumpstart private investment in energy infrastructure.

Nepal can also offer indirect tax exemptions (e.g. VAT, excise) to the project company, as well as, to contractors, subcontractors, and

Box Case 4: Strategic Incentives in India to Attract Private Investment

In the early 1990s, India began its first wave of power sector reform to address chronic underinvestment and energy shortages (Mukharjee, 2014). The Federal Ministry of Power (MoP) introduced a set of bold financial incentives to attract private sector participation (PSP), including:

- A guaranteed 16% return on equity, fully repatriable in foreign currency
- A five-year income tax holiday
- A 20% minimum equity requirement, easing capital entry
- Government-backed revenue guarantees for select "fast-track" projects

While these incentives initially sparked interest, their long-term impact was limited due to structural barriers, especially the dominance of vertically integrated State Electricity Boards (SEBs) and lack of market competition. The turning point came with the Electricity Act of 2003, which introduced unbundling, open access, and greater market transparency, enabling a more investment-friendly environment.

Post-2003, India launched two distinct PSP models for transmission:

Planning Commission Model

- Targeted intrastate projects with limited commercial viability.
- Included Viability Gap Funding (VGF) - up to 20% of project cost - to make essential but marginal projects viable.
- Followed a Design-Build-Finance-Operate-Transfer (DBFOT) structure.
- Assets were transferred back to the government post-concession.

Ministry of Power Model

- Designed for interstate transmission lines.
- Operated under a Build-Own-Operate-Manage (BOOM) model, with no subsidy.
- Projects were awarded through Tariff-Based Competitive Bidding (TBCB).
- Ownership remained with the private developer, ensuring long-term control.

The MoP model proved more successful, attracting major players like Adani and Sterlite. Its success stemmed from broader applicability, clear bidding rules, strong institutional backing, and long-term revenue certainty. As of 2023, private developers contributed to nearly 50% of India's interstate transmission capacity.

In contrast, the Planning Commission model's reliance on VGF, state-level coordination, and complex design requirements limited its scalability and uptake.

Transparent wheeling charges and independent system operation fostered a more efficient, decentralised, and resilient electricity market.

suppliers involved in transmission infrastructure, ensuring holistic cost reductions across the value chain.

Recommendation 5.2: Facilitate access to capital grants

The government can establish a Viability Gap Funding (VGF) mechanism for small transmission projects developed through PPPs. VGF is a financial support mechanism provided by the government to bridge the gap between the cost of a public infrastructure project and its expected commercial returns - especially when the project is socially or strategically important but not financially viable on its own.

Recommendation 5.3: Ensure Long-Term, Predictable Revenue Through Transparent Market-oriented Reforms

The most powerful incentive for attracting private investment in transmission infrastructure is long-term, predictable revenue. To achieve this, Nepal must establish a transparent and competitive bidding process for awarding transmission concessions, paired with clear ownership rights and a stable, independent regulatory framework. These elements build investor confidence by reducing uncertainty, enabling accurate revenue forecasting, and ensuring fair returns over the life of the project. Without this foundation, even generous fiscal incentives may fall short of mobilizing the scale of private capital needed to meet national infrastructure goals.

Nepal should also keep options for divestiture or merchant lines open for the future. For instance, India's adoption of Build–Own–Operate–Maintain (BOOM) model, allows indefinite private ownership, which has encouraged sustained private participation.

6. Complexity and unpredictability of land acquisition and RoW processes discourage PSP.

Transmission projects require long, continuous corridors that traverse multiple administrative jurisdictions, private holdings, and often community-owned or environmentally sensitive areas.

In Nepal, land acquisition is currently managed through lengthy bureaucratic procedures, often involving multiple government agencies, with limited coordination or standardisation. Compensation disputes, unclear valuation norms, and opposition from local communities have caused significant delays and cost escalations in several key grid projects.

For private investors, such uncertainty significantly increases project development risk and deters investment. Unlike public agencies, private developers typically lack the political leverage or procedural access to resolve land issues efficiently, making land-related delays a critical bottleneck to expanding PPPs in transmission.

Recommendation 6: Reforming Land Acquisition and Right-of-Way Mechanism

Recommendation 6.1: Establish a Transmission Land and RoW Facilitation Mechanism

A dedicated Transmission Land and RoW Facilitation Unit should be established under MoWERI or RPGCL. This unit would coordinate with local governments and stakeholders, fast-track land

and forest clearances, and serve as the central authority to manage land-related grievances and documentation - bringing consistency to a currently fragmented process.

Recommendation 6.2: Introduce a Market-Based and Tiered Compensation Framework

Nepal should adopt a transparent, market-reflective compensation policy tailored to geographic realities. There can be two options to achieve this:

Rather than relying on inconsistent valuation methods, compensation should be determined through independent registered valuers, ideally one appointed by the landowner and another by the project developer. These valuers must be certified professionals to ensure neutrality and technical accuracy. If valuations diverge significantly (e.g., by more than 20%), a third-party valuer can be introduced to arbitrate. This not only ensures fairness, but also helps avoid protracted legal battles, such as those seen in the Arun-3 case.

Nepal must publish clear, enforceable guidelines outlining what landowners can and cannot do under transmission lines (e.g., cultivation, construction, tree planting). These guidelines should be accompanied by compensation rates adjusted according to the level of restriction imposed. This level of clarity is essential to rebuild trust with affected communities who currently view RoW compensation as arbitrary and unfair.

Box Case 5: India's Right-of-Way Compensation Reform

For years, India's transmission projects - especially those crossing populated or high-value land - faced fierce opposition over unfair RoW compensation. Landowners protested, filed legal cases, and stalled critical infrastructure. Circle rates - government-set land values used to calculate compensation - were outdated and far below market prices. Many states lacked clear policies, and resentment simmered.

In March 2025, India took a bold step. The Ministry of Power rolled out new RoW compensation guidelines specifically for Inter-State Transmission System (ISTS) (Gupta, 2025).

Under the new system, when a transmission line is proposed, a Market Rate Committee (MRC) is formed to determine the fair market value of the affected land. The MRC is chaired by the District Magistrate or Deputy Commissioner and includes a landowner representative, a nominee from the transmission company, and up to two additional optional members as deemed necessary.

Two independent, certified land valuers are appointed; one by the developer, one by the landowners. Both the valuers must be listed officially with the Insolvency and Bankruptcy Board of India (IBBI). If the two estimates are within 20% of each other, the average becomes the compensation. If they diverge by more than 20%, a third valuer is brought in, and the average of the two closest estimates is used.

Likewise, the compensation rates are also raised significantly under the new system:

- 30% of market value in rural areas,
- 45% in municipalities and semi-urban zones,
- 60% in metro cities.

To put it in perspective,

Previously, a landowner in a semi-urban district used to get just 10% of the actual land value when transmission lines passed over their property. Under the new system, they receive 45% of the full market rate, verified by independent valuers and negotiated by a Market Rate Committee.

Recommendation 6.3: Mandate Land Acquisition and RoW Finalisation Before Project Execution

Project implementation should not begin until all required land and RoW has been secured and compensated. This can be institutionalised by legally requiring full completion of land acquisition and grievance redress prior to project financial close or contract award. Such a provision would eliminate mid-project halts, lower investor risk, and ensure community buy-in before construction starts.

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