Comments on

MoP Draft National Electricity Policy, 2026

Dr. Anoop Singh, Professor
Founder & Coordinator, Centre for Energy Regulation (CER) & Energy Analytics Lab (EAL)
Department of Management Sciences,
Indian Institute of Technology Kanpur, Kanpur - 208016 (India)
E-mail: anoops@iitk.ac.in

The Ministry of Power (MoP) notified the draft titled "Draft National Electricity Policy, 2026", issued on 20th January, 2026. The key objectives of the document is mentioned below:

Objective: The Draft National Electricity Policy (NEP), 2026 aims to provide a comprehensive roadmap for developing a reliable, affordable, financially viable, and environmentally sustainable power sector aligned with India's vision of Viksit Bharat @ 2047. The policy seeks to ensure adequate and reliable 24×7 power supply while meeting future demand growth, alongside achieving the financial turnaround of the power sector, particularly distribution utilities. It emphasizes the promotion of competitive electricity markets to reduce costs and enhance efficiency, while also increasing the share of non-fossil energy to support energy transition goals. Further, the policy focuses on strengthening grid resilience, flexibility, and cybersecurity to enable high levels of renewable energy (RE) integration. It also aims to enhance consumer-centric services, including improved quality of supply, greater choice, and effective grievance redressal mechanisms. In addition, the NEP seeks to improve industrial competitiveness through cost-reflective tariffs and the progressive reduction of cross-subsidies, while enabling energy efficiency, demand-side management, and the electrification of end-use sectors.

The document can be accessed here.

1. **Competition and Efficiency in the Vision Statement:** The vision statement of the National Electricity Policy should reflect all core principles guiding the development of the power sector. The draft vision currently states:

   "Providing reliable 24×7 quality power through a financially viable and environmentally sustainable power sector furthering energy security at an affordable price."

   While the vision appropriately highlights reliability, financial viability, environmental sustainability, energy security, and affordability, it does not explicitly include **efficiency**, which is a fundamental principle of electricity sector planning and operation. Efficiency plays a critical role in optimal utilization of generation resources, reduction of system costs, improvement of utility performance, and enhancement of long-term sustainability of the sector. The preamble of the Electricity Act 2003 also emphasizes on efficiency as well as competition, both of which should be incorporated in the vision statement.

   The present wording seems to bestow responsibility of financial viability on the sector constituents including the consumers. The responsibility of viability in essence would be borne by consumers who would have to may have to pay for inefficiency of the generation, transmission and/or distribution entities. While the viability of the sector is crucial from the perspective of attracting new investment in the sector, the viability of tariffs for efficiently

benchmarked operational and financial efficiency would be a desirable outcome.

It is therefore suggested that efficiency and competition may also be explicitly incorporated in the vision statement as suggested below.

"Providing reliable 24×7 quality power through an efficient, competitive, financially viable and environmentally sustainable power sector furthering energy security at an affordable price."

2. **Alignment of Non-Fossil Capacity Targets with NDC Commitments:** The draft National Electricity Policy, 2026 outlines the following objective:

*"**Increase** the share of non-fossil capacity to achieve the Nationally Determined Contribution (NDC) targets."*

The NDC commitments with respect to share of renewable energy capacity has already been met before the 2030 deadline. The current level of RCO/RPO has already contributed towards that goal. Further increase, with 2030 in sight, may not be desirable as the RCO/RPO targets are aligned to the NDC target.

While the long-term objective of increase in renewable capacity is desirable and well-intentioned, as the policy rightly recognizes the need for an increasing share of non-fossil energy in the electricity mix, the current formulation appears to presume or pre-empt the trajectory of future Nationally Determined Contributions (NDCs) i.e. beyond 2030.

Given that NDC commitments are determined at the national level and may evolve over time in line with international negotiations and domestic policy considerations, the formulation of the objective may instead emphasize alignment with NDC targets, which may be set higher for the period beyond 2030. It is therefore suggested that the objective may be revised as follows:

*"**Align** the share of non-fossil capacity to achieve the Nationally Determined Contribution (NDC) targets."*

Such a formulation would ensure that the policy framework remains consistent with evolving NDC commitments while retaining flexibility in planning the future generation mix.

3. **Competition in Procurement and Supply of Electricity:** The Draft NEP, 2026 currently states the objective as:

"Promote competition in supply of electricity."

While promoting competition in supply is an important policy direction, competition in the power sector operates not only at the level of retail supply but also in power procurement and market-based procurement mechanisms. Electricity markets, power exchanges, and competitive procurement processes play a critical role in ensuring transparent price

discovery, and thus efficient resource allocation.

Accordingly, the objective should reflect competition across the supply chain including procurement of electricity. It is therefore suggested that the objective may be revised as follows:

*"Promote competition in **procurement** and supply of electricity."*

4. **Numerical Target for Per Capita Electricity Consumption**: The Draft NEP, 2026 currently states:

   "Increase per capita electricity consumption to 2,000 kWh by 2030 and over 4,000 kWh by 2047, ensuring energy efficiency and responsible usage."

   This translates to a targeted growth in per capita electricity consumption represents a CAGR of about 5.92 % (7.5%) per annum for the 2030 target, and about 4.43% (4.16%) per annum from then to 2047[1].

   While improvement in energy efficiency is expected to lower the growth of electricity consumption, growing electrification of mobility and cooking, and rising cooling demand would push it upwards in future. Thus, one may not expect significant decline in growth in per capita electricity consumption unless there are significant breakthrough in efficiency of utilisation of electricity.

   Target for 2047 may thus be revised upwards. An alternate target may be to reach world's average per capita electricity consumption.

5. **Demand-Side Interventions:** The Draft NEP, 2026 currently states:

   "Enhance consumer centric service and implement demand side interventions."

   While consumer-centric services and demand-side measures are important elements of modern power system management, the present formulation remains broad and may be interpreted in multiple ways. Demand-side interventions, such as demand response, time-of-use tariffs, and load management, are increasingly being adopted to improve power system flexibility, facilitate integration of renewable energy, and enhance overall system efficiency.

   In this context, it may be appropriate for the objective to explicitly reflect the role of demand-side interventions in enhancing system flexibility. Accordingly, it is suggested that the objective may be revised as follows:

   *"Enhance consumer centric service and implement demand side interventions **to enhance power system flexibility.**"*

[1] Consumption is recorded for a duration of time (say, a year). The targets seem to specified with respect to the calendar year, while recorded data on per capital electricity consumption is generally reported for the financial year. The twin estimated of CAGR correspond to alignment of the consumption with respect to a 'nearest' matching financial year. The targets may alternatively be specified in terms of financial year.

6. Next Phase of Regulatory Reforms and Philosophy of Regulation:

The evolution of the regulatory philosophy from pure cost of service (CoS) to the normative cost of service (NCoS) has ensured that incentives for efficiency are incorporated in the regulatory approach for tariff setting through operational and financial benchmarks. While normative approach has reduced regulatory burden to some extent, the process still demands extended regulatory process, in most cases overburdening the regulatory commissions, who are short of human resources and become increasingly dependent on external resources, jeopardizing institutional memory and learning in the process.

The next phase of regulatory approach should adopt a two-prong strategy –

(i) 'Autonomous' regulatory processes with regulatory oversight

(ii) Transition towards Performance Based Regulation (PBR) with efficiency benchmarks

These may be adopted in that order. The 'autonomous' approach, which may be initially adopted for generation and transmission, entails development of data-based processes with verified and approved worksheets[2] for 'self' calculation of tariff for each year of control period. The tariff so calculated would be 'deemed to have regulatory approval and subject to true-up by the commission'. At the end of the control period, a true-up order issued by the regulatory commission would cross check the tariffs calculated and impose penalty in case of over-recovery under-recovery or allow for recovery of cost in case of under-recovery beyond a tight tolerance band of say 2-3%.

Implementation of this process must involve transparency whereby the tariff sheets are developed through a consultive process and are made available in advance on the commission's website. Following the regulatory timelines, a generator or a transmission licensee would calculate the tariff by inputting the required data. The worksheets with final calculations and tariff so arrived would be submitted to the respective commission, who would put it on its website as well the regulated entity's website for a limited duration of, say 1 month, for the regulated entity to take note of the inputs provided by the stakeholders including the commission itself. This transparent process would ensure that there is necessary buy-in from the stakeholders particularly the distribution licensees and the end consumers.

The approach to Performance Based Regulation (PBR) avoids detailed cost scrutiny for tariff determination and is rather based on performance benchmarks that drive efficient operation while allowing for recovery of cost with adjustment for efficiency improvement, and general/specific level of rise in cost heads. A preliminary approach incorporating some of these features in the cost of service regulation was suggested

[2] Some of the regulatory institutions, including Ofgem, make available the detailed tariff worksheets in public domain through its web portal. For example, https://www.ofgem.gov.uk/energy-regulation/domestic-and-non-domestic/energy- pricing-rules/energy-price-cap/energy-price-cap-default-tariff-levels

by the Centre for Energy Regulation (CER)[3] [4] and was adopted in a limited way by the GERC and CSERC.

7. Strengthening Regulatory Governance Framework:

Regulatory reforms in the sector have played a key role in bringing about changes in the sector, among others, to attract private investment, adopt sustainable technologies, adopt transparent and consultative process, set performance targets and incentivise efficiency improvement. A study conducted by the Centre for Energy Regulation (CER) for NITI Aayog identified numerous areas for strengthening regulatory governance framework in the Indian power sector. Enhancement of regulatory governance framework, among others, should focus on the following

(i) Enhancement in approved number of employees[5], particularly for the regulatory processes, and salary and benefits thereof[6];
(ii) Focused and sustained capacity building
(iii) Greater consumer participation in regulatory processes
(iv) Enhance accountability through timely submission of annual report and annual accounts, and enhancement of scope thereof[7]
(v) Greater independence of financial as well as administrative nature

The Indian power sector faces significant regulatory challenges and is expected to address even larger set of challenges with an evolving power sector. Under-staffed institutions of such importance are strained to achieve their regulatory objectives, placing greater dependence on external service providers resulting in significant loss of institutional memory and sustenance of weak institutional capacity to. Forum of Regulators (FoR), may work towards **Human Resource Adequacy Guideline**s for the ERCs, suggesting minimum staffing requirement based on current experience and international best practices. The Electricity Council, proposed in the Electricity Amendment Bill 2025, can play an important role in enabling institutional strengthening of ERCs by providing inputs ot the respective governments, who sanction the number of posts for the ERCs.

8. Institutional Strengthening of Load Despatch Centres:

Load Despatch Centres (LDCs) play a crucial role in ensuring a robust power system

[3]Singh, Anoop (2021), Comments on JSERC (Terms and Conditions for Determination of Distribution Tariff) Regulations, 2020, Centre for Energy Regulation, IIT Kanpur. Available at https://cer.iitk.ac.in/newsletters/regulatory_insights/Volume03_Issue02.pdf

[4] Deliberations of Regulatory Manthan on the topic can be accessed at https://cer.iitk.ac.in/RM/rm1

[5] The regulatory institutions across the world are well staffed to undertake regulatory functions in a timely manner. Analysis by CER finds that number of employees at some of the key regulatory institutions including Australia Energy Regulator (AER), Federal Electricity Regulatory Commission (FERC) and Ofgem (UK) is estimated to be 1-2000 even though their regulatory functions are limited on account of competition in generation and retail supply business. While some of these regulators also regulate other sectors especially gas, the predominant employee share is on account of the electricity sector regulation. In comparison, number of regulatory employees at electricity regulatory commissions in India range from 10-100.

[6] Salary structure at regulatory institutions should be higher than the industry level (regulated entities), helping to place them at the higher pedestal of independence and integrity.

[7] CER deliberated on these issues in detail at its Regulatory Conclave on "Regulatory Governance in the Indian Power Sector: Reporting and Accounting Framework for ERCs" in July 2024. For further details, see

operation for secure and reliable system operation. Their role becomes even more important with uncertainties associated with VRE, which are expected t play even greater role in the future. Apart from ongoing engagements with respect to market operation, ancillary services, greater challenges emerge as they play an important role in planning for ensure resource adequacy, and future introduction of the capacity market.

The recommendations of Capacity Building of Indian Load Despatchers' (CABIL), which was endorsed by the Forum of Regulators in 2018, should be updated in the current context and placed for adoption across states. **Adequate human capacity, and continuous capacity building efforts are required to ensure that the LDCs are future ready.** Functional and financial autonomy is also vital to the independence of the load dispatch centres which are expected to play an impartial role especially in a sector with increasing role of open access and retail supply competition. **Organisational separation and corporatisation of LDCs should be the medium-term goal for the LDCs.** The NEP should highlight the need for institutional strengthening of LDCs.

9. Regulatory Impact Assessment (RIA)

The key regulations affecting tariff for generation, transmission and distribution should be tested against the potential impact for key stakeholders. The existing regulatory approach does not provide an assessment of available alternate options for tariff regulation including key regulated parameters on stakeholders, both the regulated entities and the buyers (distribution licensees and the end consumers). The NEP should suggest a regulatory role for conducting **Regulatory Impact Assessment (RIA)** to be undertaken by the Regulatory Commissions, before the adoption of tariff regulations for the upcoming control period and changes thereof thereby safeguarding the interests of all stakeholders, particularly end consumers. **The international best practices demonstrate the transparent approach adopted by the regulatory institutions thereby ensuring necessary buy-in from stakeholder and also reducing potential for disputes later.**

10. Data Governance: Strengthening Data Availability and Accessibility

Reliable and transparent decision-making in the power sector increasingly depends on the availability of high-quality data and the ability of institutions to access and analyse such information in a timely manner. Data availability and accessibility of sufficient and timely data for better decision making and strengthening research based on data in the Indian context. Appropriate frameworks should therefore be developed to facilitate standardized data collection, sharing, and dissemination across sectoral entities while ensuring data integrity, transparency, and usability for policy formulation, regulatory oversight, and

academic research.

A sector level data governance guidelines for ease of data access with necessary safeguards should be put in place ensuring that the Indian researchers do not end up working with data of other countries (with limited relevance in the Indian context), thus avoiding another kind of brain drain for the country.

11. **Resource Adequacy:** The provision relating to resource adequacy may benefit from explicitly recognizing the importance of cost-effectiveness in addition to reliability. The Draft NEP, 2026 currently states:

    "A structured mechanism for resource adequacy must be established at national, state, and distribution utility levels to ensure reliable 24×7 power supply."

    While ensuring reliability of supply is a primary objective of resource adequacy planning, **it is equally important that such planning ensures cost-effective procurement and utilization of resources.** Resource adequacy frameworks are intended not only to maintain reliability but also to optimize resource mix and minimize the overall cost of supplying electricity to consumers (as enshrined in the Electricity Act 2003). Accordingly, it may be appropriate to explicitly incorporate the principle of cost-effectiveness in the formulation. **Inadequate consideration of cost impact may result in financial burden on discoms and impact the consumer tariffs**.

    It is therefore suggested that the provision may be revised as follows:

    "A structured mechanism for resource adequacy must be established at national, state, and distribution utility levels to ensure reliable and ***cost-effective*** *24×7 power supply."*

    This revision reflects the dual objective of ensuring reliability while maintaining economic efficiency in power system planning and operations.

12. **FPPCA-Based Recovery of Power Purchase Cost:** The provision relating to cost recovery emphasizes the importance of ensuring that tariffs reflect the actual cost of supply in order to maintain financial sustainability of the power sector. The Draft NEP, 2026 currently provides that:

    "**Power purchase cost increases** must be automatically passed through to consumers on a monthly basis."

    While the intent of enabling timely pass-through of power purchase cost variations is appropriate, the **NEP should also mandate annual assessment of reasons behind increase in tariff which should be analysed, updated and tracked by the ERCs.**

    The mechanism of Fuel and Power Purchase Cost Adjustment (FPPCA) or Fuel and Power Purchase Adjustment. Surcharge (FPPAS) framework introduced by most of the

SERCs/JERCs in the respective state/UTs provides for automatic passthrough of increase in power purchase cost **with certain limitations. The draft NEP should recognize the limitation on such pass through. The clause may be modified as,**

"**Change in Power purchase cost** must be automatically passed through under the mechanisms approved by the appropriate commission."

13. **Stabilisation Fund:** The provision relating to cost recovery also proposes the creation of stabilization funds to manage power purchase cost fluctuations. While the intent of managing tariff volatility is understandable, the proposed mechanism may be relied upon more often than increase in tariff or improvement in efficiency. **While this may temporary fill the vacuum left due to the court mandated ban on creation of new regulatory asset, any reasonable amount of stabilization fund would soon be exhausted across the states with high burden of regulatory assets.**

    In the absence of clear institutional design, funding mechanism and operational framework, the proposed stabilisation fund mechanism may introduce ambiguity in tariff determination process and would shield operational and financial inefficiency of utilities.

    Accordingly, the provision relating to stabilization funds may either be reconsidered or be accompanied by clear policy guidance regarding its design, governance, and operational framework.

14. **Amendments to Tariff Policy:** The National Electricity Policy is intended to outline the **overall strategic vision and direction for the development of the power sector**.

    Apart from highlighting the importance of timely issuance of tariff orders, timelines for regulatory proceedings, and separation of distribution and supply tariffs, these should be reflected in the tariff policy through an amendment. Apart from this, a number of other provisions of NEP, for example pass through of fuel and power purchase cost, also point towards amendments in the tariff policy. Post NEP 2026, such amendments should be reflected in the tariff policy as well.

15. **Accountability for AT&C Loss Reduction**: The provision on loss reduction may require alignment of responsibility with the entity that is directly accountable for operational performance.

    The Draft NEP, 2026 currently provides that:

    *"…**State Governments** must target single-digit AT&C losses, with commercial loss reduction and timely payments of Government and local body dues." (emphasis added)*

    While State Governments have an important role in enabling sectoral reforms and ensuring timely payment of dues, AT&C loss reduction is fundamentally an operational responsibility

of the Distribution Licensees, some of whom are private licensees as well. **Accordingly, the obligation may be more appropriately placed on the entity directly responsible for network management, billing, collection, and loss control i.e. the distribution licensees.**

It is suggested that the provision may be revised as follows:

"…**Distribution Licensees** must target single-digit AT&C losses, with commercial loss reduction and timely payments of Government and local body dues."

16. **Storage Obligation on for Agri PV:** The provision relating to solarisation of agriculture feeders with storage may require reconsideration from the perspective of operational responsibility and cost recovery.

    The Draft NEP, 2026 provides that: *"By 2030, **States** shall complete the solarisation of all agriculture feeders, suitably backed by storage, to enable reliable power supply to farmers, alongside the solarisation of individual agriculture pumps and deployment of stand-alone solar pumps wherever required, thereby contributing to a reduction in the subsidy burden on State Governments." (emphasis added)*

    Solarisation of agricultural feeders/ agricultural pumps not only enables greater adoption of renewables, it is also instrumental in reducing subsidy burden for discoms. The proposed clause seems to place obligation of energy storage system for agricultural feeders as well as individual agri-PV pumps on the respective state governments. This, in turn, would be undertaken by the distribution licensees placing significant cost burden leading to higher overall tariffs.

    The overall economics of storage investment for agricultural feeders does not seem to be justified as the original objective of solarization of agricultural feeders/ agricultural pumps was to utilize solar energy during the day. It is more economical to ensure the desired reliability through gird connected solar PV, if required, (rather than through feedres or individual for pumps) with the available portfolio of power supply sources including storage.

17. **Return on Investment and Incentive Framework:** The provision relating to attracting private investment highlights the need for predictable returns and stable regulatory frameworks in order to mobilize capital for the power sector. The Draft NEP, 2026 provides that return on investment must be competitive with other sectors and that regulatory frameworks should include performance-based incentives.

    While ensuring attractive returns is important for attracting private capital, the regulatory framework must also ensure that returns remain **fair and competitive**, while encouraging operational efficiency and accountability. Study undertaken at the Centre for Energy Regulation (CER) estimated return on equity for a number of infrastructure sub-sectors

including power sector. It was found[8] that the estimated cost of equity for transmission investment is significantly lower in comparison to the regulated return on equity. Accordingly, it is suggested that the provision may be revised as follows:

"The return on investment must be fair and competitive, and performance-based incentives & disincentives."

The regulatory design for incentives should be applicable in case of performance beyond the mandated benchmark ensuring that the investment frameworks remain attractive while also incorporating **appropriate incentives and disincentives linked to performance**, thereby strengthening accountability and efficiency in operations.

18. **Role of Competition in the Power Sector:** The provision on building a competitive market appropriately recognizes the importance of promoting competition in the power sector. The Draft NEP, 2026 currently provides that:

"Competition across the power sector must be promoted to benefit consumers."

While the emphasis on consumer benefit is appropriate, the objective of promoting competition extends beyond consumer welfare and also contributes to broader sectoral outcomes. It is suggested that the provision may be elaborated as follows:

"**Competition across the power sector must be promoted to benefit **(a) end consumers, (b) cost competitiveness, and (c) to promote investment and efficiency."

19. **Development of Short- to Medium-term Capacity Market**

At the same time, the effectiveness of competitive electricity markets depends on the presence of **appropriately calibrated resource adequacy mechanisms** to ensure long-term reliability of supply. Competitive energy markets alone may not always provide adequate signals for investment in firm capacity, particularly in systems with increasing penetration of variable renewable energy and evolving demand patterns. In this context, there is a need to explore the development of **capacity markets**, which can provide clear and predictable investment signals for capacity addition, ensure availability of adequate generation resources during peak demand conditions, and support long-term system reliability while maintaining

[8] Results indicate that regulated (post-tax) returns (~14% base + grossing up for tax) exceed the estimated post-tax cost of equity (11% - 12.5% for conventional generation and 10-11% for transmission) calculated using CAPM and multi-factor models. Kewal Singh, Anoop Singh, Puneet Prakash, 2022, "Estimating the cost of equity for the regulated energy and infrastructure sectors in India" Utilities Policy, http://dx.doi.org/10.1016/j.jup.2021.101327
Singh, A., Comments on CERC's (Terms & Conditions for tariff) Regulations, 2024 [Draft] Regulatory Insights, Volume 6, Issue 4, Centre for Energy Regulation (CER), IIT Kanpur.
https://cer.iitk.ac.in/newsletters/regulatory_insights/Volume06_Issue04.pdf
Singh, A., Opinion on UERC (Terms and Conditions for Determination of Multi Year Tariff) Regulations, 2024 [Draft]Regulatory Insights, Volume 6, Issue 4, Centre for Energy Regulation (CER), IIT Kanpur.
https://cer.iitk.ac.in/periodicals/regulatory_insights/Volume07_Issue02.pdf

competitive market outcomes.

This clarification highlights the broader role of competition in improving cost efficiency, encouraging investments, and strengthening overall sector performance.

20. Exemption from Universal Service Obligation for Large Consumers:

"Regulatory Commissions… may exempt the distribution licensees from the Universal Service Obligation in respect of consumers having a contracted load of 1 MW and above, capable of self-procurement."

"State Commissions should exempt manufacturing enterprises, Railways, and Metro Railways from payment of cross-subsidies and surcharges."

The Draft NEP, 2026 proposes that distribution licensees may be exempted from the Universal Service Obligation (USO) for consumers having a contracted load of 1 MW and above, who are capable of self-procurement of electricity through open access. While this proposal aims to enhance market competition and improve cost competitiveness of industrial consumers, its implications for the financial viability of distribution licensees require careful consideration.

Once such consumers migrate outside the DISCOM supply framework, the distribution licensees would lose a significant portion of their **cross-subsidizing consumer base**. These consumers currently contribute to the **gross subsidy pool**, which supports lower tariffs for subsidized consumer categories. The rate of increase in subsidized tariffs may not be able to match the loss of cross-subsidy resulting from the exit of such consumers.

The **Electricity Act, 2003** recognized this risk and therefore provided for **cross-subsidy surcharge and additional surcharge**, so that distribution licensees do not suffer immediate and significant financial fallout from the migration of cross-subsidizing consumers. While the Act also envisages a gradual reduction of cross-subsidy, this objective has not translated effectively in practice.

In this context, the **National Electricity Policy should suggest clear pathways for continuous and gradual reduction of cross-subsidy while determining consumer tariffs**. The SERCs/JERCs should specify a **trajectory for reduction of cross-subsidy and cross-subsidy surcharge for each tariff control period**. At the same time, distribution licensees should undertake concerted efforts to continuously improve **operational efficiency and optimize power procurement costs**.

If distribution licensees are exempted from the Universal Service Obligation for consumers having contracted load of **1 MW and above**, the DISCOMs should also be **exempted from the mandated resource adequacy obligation for such consumers**. This would open up significant challenges for managing discom's finances who have recently entered into or are planning to enter into long-term PPA for its consumers, including those who would exist its cosnuemr base soon.

Without such explicit exemption under the **resource adequacy framework**, DISCOMs and the remaining consumers of the DISCOM would be saddled with significantly higher costs that would need to be recovered through tariffs. This would not only **decelerate the financial recovery of DISCOMs**, but also place them in a **seriously disadvantaged position in terms of retaining large consumers within their supply base**.

21. **Industrial Competitiveness Vs Viability of Discoms:** The proposal relating to improving industrial competitiveness through exemption from cross-subsidy and related charges may require a more balanced consideration of its implications for distribution licensees and the broader tariff structure. The current draft states that:

"State Commissions should ***exempt manufacturing enterprises****,* ***Railways, and Metro Railways*** *from* ***payment of cross-subsidies and surcharges****."*

The proposal to exempt manufacturing enterprises, Railways, and Metro Railways from cross-subsidy and related surcharges requires a more balanced assessment of its implications for distribution licensees and the broader tariff architecture. While reduction of tariff distortions is a legitimate regulatory objective, exemption from cross-subsidy does not, by itself, establish a clear or proportionate pathway to industrial competitiveness.

First, the relationship between electricity tariff reduction and industrial competitiveness is neither uniform nor necessarily strong across sectors. Competitiveness depends on the overall cost structure of production, including raw materials, labour, logistics, financing costs, technology intensity, and scale efficiencies. In many sectors, electricity constitutes only a limited share of total expenditure. Accordingly, even where electricity tariffs are reduced, the resulting impact on final product competitiveness may be modest unless the concerned industry is genuinely electricity-intensive. A general exemption, therefore, risks treating all manufacturing categories alike despite substantial heterogeneity in energy cost dependence.

Available financial data across manufacturing sectors suggests that energy expenditure constitutes a relatively modest component of total revenue for most industries. As illustrated in Figure 1, energy expenditure for the majority of manufacturing sectors typically lies in the range of about **0.5–28% of total expenditure**, with a number of key sectors recording below **5%**.

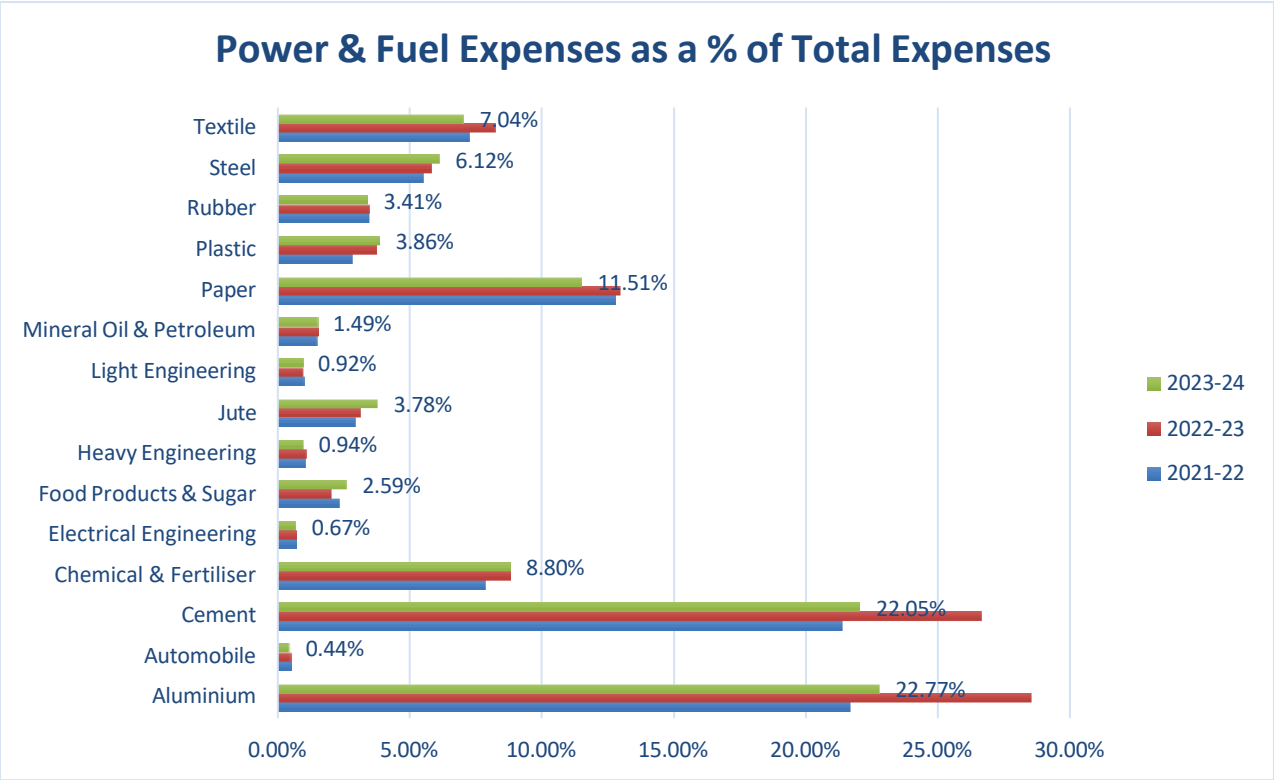

Figure 1. Energy Expenditure as a Share of Total Expenditure across Selected Industrial Sectors[9]

Among these, **Aluminium and Cement sectors emerge as the two most energy-intensive industry in terms of direct expenses towards the same**, with electricity and fuel expenditure accounting for around **22-23% of total expenditure in 2023-24 and around 26-28% in 2023-24**. FPulp & paper, chemical & fertiliser and testile sectors record a power and fuel expenditure share of 7-12%. Some of the energy intensive sectors including Iron & Steel have captive mines used for captve generation, and hence do not incur significant direct expenditure on purchase of electricity from the distribution licensees.

It is also important to highlight that the energy intensive industries make use of captive generating capacity with captive coal mine or coa linkages. In case of the later the energy purchase is in the form of coal, which is converted by the

Further, evidence indicates that **many energy-intensive industries already source a substantial share of electricity independently of the distribution utility supply framework**. Data on captive power plants suggests that industries consume approximately **190,495 GWh of electricity from self-generation out of a total industrial consumption of about 319,958 GWh**, implying that **nearly 60% of industrial electricity demand is already met through captive or self-generation sources**. Energy-intensive sector account

[9] Source: Analysis carried out by CER based on CMIE Prowess financial database

for higher share of self-generation of electricity from captive power plants (Figure 2)[10]. In **2023-24**, share of electricity consumed from self-generation was was **88% in Aluminium, 77% in Pulp & Paper, 76% in Fertiliser, 74% in Sugar, 73% in Non-ferrous industries, 62% in Iron & Steel and 58% in Cement**.

Captive electricity use is particularly pronounced in energy-intensive sectors. For instance, **Iron & Steel (~52,054 GWh), Aluminium (~46,099 GWh), Petroleum refining (~18,776 GWh), Cement (~16,100 GWh), and Chemical industries (~14,786 GWh)**. The sector-wise data clearly indicates that several industries already meet a dominant share of their electricity demand through captive sources.

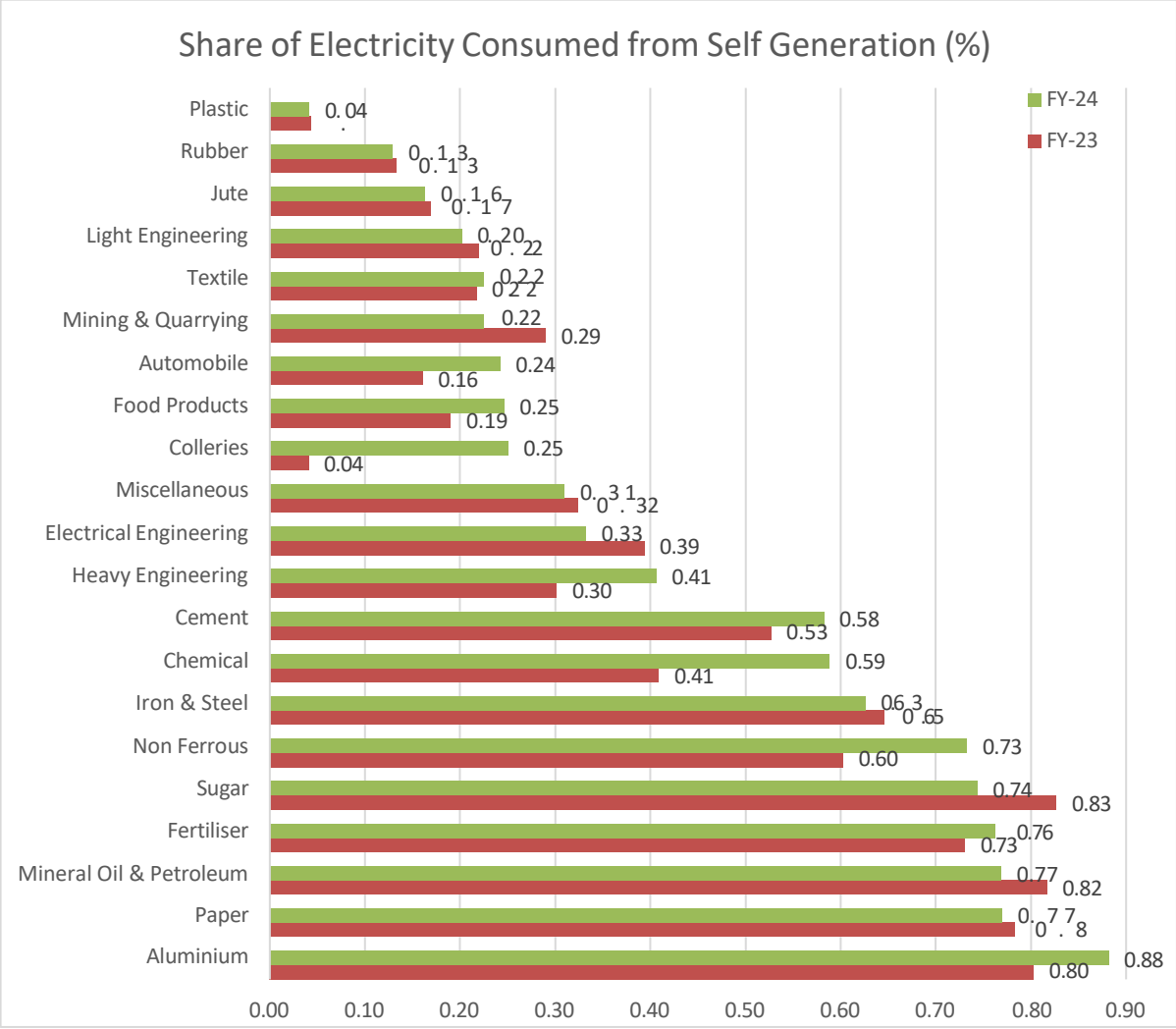

Figure 2. Industry-wise electricity generation and consumption from captive power plants[11]

[10] Some of the sectors represent integrated as well as secondary processing firms operating therein.
[11] Source: Industry-wise electricity generation and consumption by captive power plants (General Review 2024 & 2025, CEA).

These figures suggest that the industries with the higher energy intensity have lower dependency on discoms, and rely more on captive generation. Apart from this, electricity procurement through traders or power exchanges via open access route, though in a limited manner, also substitutes procurement from discoms. Consequently, the incremental 'competitiveness' gains from blanket exemption from cross-subsidy charges in retail tariffs may be limited for precisely those sectors that consume the largest volumes of electricity. Albeit this would significantly impinge on the financial viability of disoms. This, in turn, may force the discoms to enhance fixed charges for tariff for industrial as well as other consumers.

A similar pattern is observable in the case of transport systems cited in the Draft. In the case of **Delhi Metro Rail Corporation (DMRC)**, electricity expenditure amounts to approximately **₹39,756 lakh** against total expenditure of about **₹9,74,938 lakh**, implying that electricity constitutes roughly **4.1% of total expenses,** as shown in Table 1 and Table 2. The dominant cost components of metro systems arise from capital investment, depreciation, financing costs, employee expenses, and infrastructure maintenance (Table 1). **Expenses towards overall electricity purchase represent only 4% of total expenditure in 2024-25 (Table 2).** The share may be even smaller in case of other metro corporations with much lower network of routes.

Table 1. Expense Structure of Delhi Metro Rail Corporation (DMRC), 2024–25[12]

S. No.	Expense Category	Amount (₹ lakh)	Share in Total Expenses (%)
1	Operating Expenses	3,52,824	36.23
2	Employee Benefits Expense	1,92,350	19.74
3	Finance Costs	58,138	5.97
4	Depreciation & Amortisation	2,60,937	26.79
5	Other Expenses	1,10,688	11.35
	TOTAL EXPENSES	9,74,938	100

So: *Annual Report 2024-25*, Delhi Metro Rail Corporation Ltd.

Table 2. Electricity Expenditure within the Overall Cost Structure of DMRC, 2024–25

Item	Value
Electricity Expense[13]	₹ 39,756.43 lakh
Total Expenses	₹ 9,74,937.90 lakh
Electricity Expense as % of Total	4.08 %

[12] *Source: Compiled from DMRC financial statements.*

[13] This also includes direct procurement of renewable energy by DMRC.

Expenses	

So: Based on data from *Annual Report 2024-25*, Delhi Metro Rail Corporation Ltd.

Table 3. Specific Electricity Consumption in Passenger and Freight Rail Services (kWh per 1000 Gross Tonne Kilometres)

Service Type	**Energy Source**	**Unit**	**2023-24**	**2024-25**
Passenger Services	Electricity	kWh	18.80	18.70
Goods Services	Electricity	kWh	6.22	6.50

So: Indian Railways Year Book 2024-25

Likewise, operational statistics for **Indian Railways freight operations**, reported in Table 3**,** indicate a specific electricity consumption of approximately **6.5 kWh per 1000 gross tonne kilometres (GTKMs)**. After adjusting for the difference between gross and net freight weight, back of the envelop calculations suggest that this may translate to roughly **13 kWh per 1000 tonne-kilometres**. At an average electricity tariff of approximately **₹7 per kWh**, the electricity cost associated with transporting **1000 tonnes of goods over 1 km would be roughly ₹90–₹100**, or approximately **₹0.10 per kg for transport over 1000 km**. Relative to total logistics costs, which include wagon costs, handling, infrastructure charges, and other operational expenditures—the electricity cost component remains very modest. While electricity prices may influence costs for certain low-value bulk commodities, their overall impact on logistics competitiveness appears limited.

Taken together, these observations suggest that expenditure towards electricity procurement from discoms, generally represents a smaller component of the broader cost structure governing industrial production and logistics systems. Accordingly, while electricity pricing reforms may improve cost efficiency at the margin, their overall influence on sectoral competitiveness must be assessed in the context of the full production and logistics cost structure. Removal of cross-subsidy may improve tariff neutrality by reducing distortions in retail electricity pricing; however, competitiveness in manufacturing and logistics is influenced by a much broader set of structural factors including raw material costs, labour productivity, capital intensity, logistics efficiency, and financing costs. **In the absence of empirical evidence demonstrating that cross-subsidy constitutes a binding constraint on industrial and logistics competitiveness, a blanket exemption and thus loss of cross-subsidising customer base would significantly undermine financial viability of discoms, many of which are already reeling under burden of historical and present losses. This does not mean to suggest that inefficiency of discoms should be shielded. The NEP should lay down a strategy to techno-commercial-regulatory**

pathway to transform the discoms into competitive and profitable entities. A <u>twinning approach</u> wherein efficient best practices and experience sharing through inter-discom cooperation with profitable government and private discoms help address the institutional and operational gaps.

22. Exemption from Service Obligation and under-recovery of fixed cost through tariff:

The prevailing tariff design across consumer categories is undermined by significant under-recovery of fixed costs through fixed charges. The cross-subsidising categories fare better in this context in comparison to the cross-subsidised categories. Departure of industrial consumers would further expose discoms to the skewed cost structure as revenue stream becomes more riskier with rising share of behind the meter solar PV installations

Migration of industrial consumers outside the DISCOM's customer portfolio, or exemption from cross-subsidy-related charges, could significantly narrow the revenue base available for recovering capacity charges for PPAs and network costs while also supporting supply to subsidised consumer categories. Unless accompanied by a credible mechanism for revenue replacement, such exemptions may result in **increased tariff burdens on remaining consumers, greater dependence on state subsidy support, or deterioration in the financial sustainability of distribution utilities**.

In this context, rather than introducing blanket exemptions for select consumer groups, the policy may consider articulating a **clear and predictable national trajectory for the gradual reduction of cross-subsidy**, consistent with the statutory intent under the Electricity Act for progressive reduction of cross-subsidies. Such a calibrated approach would enable improvement in tariff neutrality while ensuring that the transition does not abruptly erode the cross-subsidy base, weaken DISCOM finances, or destabilise the tariff framework.

23. **Enforcement of RCO targets by SERCs:** In Clause 5: Generation, Sub-clause 5.1 Renewable Energy, Para 2, the Draft states that:

"State regulators must enforce RCO targets set under the Energy Conservation Act. Such obligations may be met by ***procurement of green power or Green Attributes*** *or any other mechanism such as RCO Buyout under the framework* ***notified by the Central Government*** *and* ***suitable regulatory provisions*** *shall be made by the* ***Central Commission****. Policy measures shall be undertaken to* ***promote and incentivize co-generation as envisioned in the Electricity Act, 2003****."*

While the intent of the provision is understood, the present formulation does not adequately reflect the institutional framework governing RCO enforcement under the existing statutory and policy architecture.

Under the current framework, the enforcement of RCO does not lie solely with the State Electricity Regulatory Commissions (SERCs). The responsibility is distributed across multiple entities under the Electricity Act, 2003 and the Energy Conservation Act, including the Bureau of Energy Efficiency (BEE), Appropriate Governments, and Regulatory Commissions, each operating within its respective jurisdiction.

Further, the statement that *"suitable regulatory provisions shall be made by the Central Commission"* may require clarification. The Central Electricity Regulatory Commission (CERC) would typically come into picture only in relation to mechanisms such as trading of green attributes or buy-out frameworks, where a centralized market or national-level mechanism is involved.

However, procurement of green power remains primarily within the domain of the State Electricity Regulatory Commissions, as part of their tariff-setting and regulatory jurisdiction over distribution licensees and obligated entities within the State. The present wording may therefore create an unintended impression that the Central Commission is responsible for regulatory provisions relating to procurement of green power.
It is therefore suggested that the text may be recast to clearly distinguish between:

- State-level regulatory responsibility for procurement and compliance monitoring of green power obligations; and

- Central-level mechanisms, such as green attribute markets or buy-out frameworks, where the Central Commission may play a role.

Such clarification would ensure consistency with the Electricity Act, 2003, the Energy Conservation Act framework for RCO, and the earlier National Electricity Policy approach, while also avoiding potential ambiguity regarding institutional responsibilities for implementation and enforcement.

24. **Promotion of Co-generation for Non-renewable Sources?:** In Clause 5 (Generation), Subsection 5.1 (Renewable Energy), Para 2 states: *"Policy measures shall be undertaken to promote and incentivize co-generation as envisioned in the Electricity Act, 2003."*

This appears to be incorrectly stated. The **Electricity Act, 2003** specifically refers to **promotion of co-generation from renewable energy sources**, and not co-generation in general (i.e. including non-renewable sources). Accordingly, the provision may be recast to align with the Act as follows:

"Policy measures shall be undertaken ***to promote and incentivize co-generation from renewable energy sources*** *as envisioned in the Electricity Act, 2003."*

25. **Institutional Responsibility for Development of Electricity Markets:** In Clause 5 (Generation), Subsection 5.1 (Renewable Energy), Para (3) on Market-Based RE Growth, the draft states that:

"The ***Central Government shall evolve appropriate market-based frameworks*** *and the* ***Central Commission shall make the necessary regulatory provisions*** *for mechanisms such as Virtual Power Purchase Agreements and Bilateral Contract Settlement to attract investments in non-fossil fuel-based generation capacities."*

In line with the provisions of the Electricity Act, 2003 (Section 66), development of electricity markets lies within the domain of the Appropriate Commission. Accordingly, the development of market-based frameworks lies with the Commission. In the case of a nation-wide market, CERC has played vital role of issuing relevant market regulations.

The Central Government may provide policy direction, strategic guidance, and enabling signals for market evolution, but it does not evolve the market framework itself. The present wordings blur the institutional responsibility. This may also avoid legal disputes that may arise in the context of design and operationalization of market mechanism in future.

It is suggested that the provision may be recast to reflect that the Commission develops the market framework and corresponding regulatory provisions, while the Central Government provides policy direction to facilitate such market development.

26. Clarification on Role of Distribution Licensees in RE-Storage Deployment: In Clause 5 (Generation), sub-clause 5.1 (Renewable Energy), Para (5) RE with Storage, the draft states:

"Hybrid projects (VRE plus storage) should be promoted for reliability and optimized transmission use. ***Distribution licensees should <u>build</u> local RE with storage to reduce losses.*** *Governments and regulatory commissions must support such projects and specify*

CUF targets." (emphasis added)

The present wording does not appear consistent with the prevailing institutional and operational framework of the power sector. Distribution licensees generally do not develop generation assets, as the development of generation capacity is typically undertaken by generating companies, including State GENCOs or independent power producers. Distribution licensees primarily function as procurement and supply entities responsible for power purchase and delivery of electricity to consumers, rather than developers of generation or storage infrastructure. Role of storage is envisaged for ensuring reliable grid operation including addressing congestion in a cost-effective manner.

Further, procurement of storage or other flexibility resources should ideally be guided by appropriate RE integration studies. Such studies help identify optimal locations, capacity requirements, and the most suitable flexibility options, thereby avoiding inefficient investments and ensuring that deployment of flexibility resources is aligned with actual grid conditions, renewable integration requirements, and loss reduction objectives.

Accordingly, the present statement may not accurately reflect the institutional roles and operational practices within the electricity sector. It may therefore be more appropriate to reframe the provision as follows:

"Distribution licensees should get into agreements with local RE with storage, or standalone storage, or demand response resources, based on appropriate RE integration studies, to reduce losses."

This revision would **better reflect the institutional roles within the electricity sector, recognize the role of demand-side flexibility, and ensure that deployment of RE-storage and other flexibility resources is supported by appropriate technical and system-level assessments.**

24. Demand Response and Aggregator Participation:

The above clause may also appropriately recognize the role of demand response as a flexibility resource in the distribution system. Demand response is a recognized flexibility mechanism capable of supporting renewable energy integration, reducing peak demand, and alleviating congestion in distribution networks. In several cases, **demand response can provide a more cost-effective and operationally efficient alternative to physical storage or additional generation capacity, while still contributing to improved system reliability and reduction of technical losses.**

The policy proposes the promotion of demand response programmes by distribution licensees. However, a clear regulatory framework is required to enable participation of demand response resources and aggregators in electricity markets.

Accordingly, State Commissions may develop regulatory frameworks for demand response programmes, while model regulations for such mechanisms may be developed through the Forum of Regulators to ensure consistency across states. In addition, an aggregator model may be introduced to enable aggregation of demand response resources and facilitate their participation in electricity markets.

27. **Clarification on P2P Trading and Surcharge Exemptions:** In Clause 5 (Generation), Subsection 5.1 (Renewable Energy), under Consumer-Driven RE & P2P Trading, the draft states that:

    "Rooftop solar with storage, peer-to-peer (P2P) energy trading, and Open Access to RE, free from surcharges must be promoted."

    Peer-to-peer (P2P) energy trading mechanisms already exist in principle, as by displacement, electricity generation at the distribution end is consumed largely by other consumers thus reducing network losses. However, with increase in behind the meter RE penetration, it may not be absorbed locally and may need to be either stored or wheeled across the grid for consumption. With growing share of renewables, more and more of network cost burden falls on conventional sources as it alters the relative prices while consumers bears the whole burden in any case. Significant role of P2P transaction may be limited by the increased complexity of transactions, the associated hardware, network and data center cost and associated energy consumption. **NEP should lay down clear roadmap to evaluate techno-economic drivers for large scale P2P trading and its cost impact on the discoms and the end consumers.**

    Successful pilots based on their economic drivers and contribution to grid stability and resilience should grid adoption of P2P trading. An integrated regulatory framework covering demand response, P2P trading, energy storage and reliability services may be promoted through a <u>regulatory sandbox approach</u> and piloted in selected areas of discoms across selected states with necessary grid preparedness.

28. **Repowering of Aging Renewable Energy Projects – Coordination with DISCOMs:** In Clause 5 (Generation), Subsection 5.1 (Renewable Energy), under Repowering, the draft states:

    "Aging RE projects must be upgraded with efficient technologies."

    While the intent to promote repowering is appropriate, the provision may require further clarity from the operational and contractual perspective. Repowering of existing renewable energy projects may involve changes in installed capacity, generation profile, and grid injection, which have implications for existing power purchase arrangements and network planning.

Accordingly, repowering should be undertaken with provision for first right of revision/refusal with the appropriate DISCOM, particularly where the existing project is tied to a power purchase agreement with the distribution licensee. Further, any revised capacities arising out of repowering should be undertaken only after establishing system feasibility and ensuring compatibility with the existing grid and contractual framework. **To ensure that the price discovery mechanism adopted for such repowered capacity is competitive, the Swiss Challenge approach for public private partnership (PPP) may be adopted. The Ministry may issue appropriate guidelines for implementing the same.**

It may therefore be appropriate to revise the provision as follows:

"Aging RE projects must be upgraded with efficient technologies and on competitive basis, with provision for first right of revision/refusal with the appropriate DISCOM, and such revised capacities should be undertaken only after establishing system feasibility."

25. **Capacity Market and Short-Term Trading under Resource Adequacy:** Variation in demand and supply mix, resulting in imbalance between the expected demand and the tied-up resources under the applicable resource adequacy framework, also opens up avenues for short-term trading of 'capacity'. Development of such a 'Capacity Market' would enable distribution licensees as well as large captive/open access consumers, to ensure their RA compliance while also providing a window for offloading excess capacity for short-term period for those who have tied up excess resources.

    The ministry and CERC should spearhead consultation process for developing a framework for Capacity Market that is suitable for the Indian context, which does not mandate market participation by all generation resources. This would require a robust compliance mechanism, capacity monitoring with transparent information sharing, and a robust market monitoring framework. A pilot may be introduced by CERC under Regulatory Sandbox approach, wherein Grid-India may develop tools and mechanism for tracking capacity and contractual obligations. The compliance mechanism must ensure penalty in the form of 'regulated' capacity contract at best available price in case an obligated entity fails to do so.

26. **Mandatory Implementation of AGC and Unified Ancillary Services Framework:** Mandatory implementation of AGC should be rolled out within a period of 2–3 years of issue of this policy. All thermal generating units which have been set up over the past 10 years should be brought under AGC on priority basis. The Forum of Load Despatchers (FoLD) as well as FoR (Forum of Regulators) should engage in stakeholder consultation to get necessary buy-in from the generators to accelerate this process. The Central Government may provide partial financial support for accelerated implementation of AGC for intra-state generating stations, this will further enable participation of intra-state generating stations into the national level ancillary services market.

Frequency Control Ancillary Services are best delivered through a Unified Ancillary Services market mechanism, as being implemented through SRAS and TRAS. However, in case of localized Ancillary Services requirement, for example for voltage support and black start services, localized/state/region specific mechanism may be designed through stakeholder discussions at FoR and FoLD.

The proposal for time-bound AGC implementation is appropriate in view of increasing renewable penetration and the need for enhanced grid flexibility. However, uniform technical standards, telemetry requirements, and clear cost recovery mechanisms must be specified to ensure consistent implementation across jurisdictions. Accordingly, it is suggested that AGC rollout be supported by harmonized regulatory provisions and coordinated institutional framework so that ancillary services are delivered efficiently without market fragmentation.

27. **Regulatory Framework for Price and Volume Hedging:** In the absence of an appropriate regulatory framework for price and volume hedging by the regulated entities, their participation under such contracts would remain limited. A regulatory framework enabling such risk hedging strategies should be permitted in a cost-effective way and a framework for cost-effective risk hedging.

The recognition of hedging constraints for regulated entities is important, particularly in the context of evolving market-based mechanisms such as capacity markets and bilateral contract settlements. Without explicit regulatory clarity on admissibility of hedging costs and prudence checks, regulated entities may remain risk-averse, thereby limiting effective market participation.

Accordingly, it is suggested that an enabling regulatory framework be developed specifying permissible hedging instruments, exposure limits, prudence norms, and cost pass-through principles to ensure risk mitigation while safeguarding consumer interests.

28. **Unified National Grid Code:** Even though the country has a single synchronized grid, the Grid Code as well as operational practices differ at the inter- and the intra-state level, as well as across the states. To ensure grid reliability and its resilience, the country should adopt a harmonized **Unified National Grid Code with due consideration of differentiated timelines to address sequential operational requirements at the inter- and the intra-state level in a progressive manner with clear timeline for harmonisation of critical aspects of grid operation. A Unified National Grid Code would also ensure development of a nationwide market for ancillary services especially through participation of entities at the intra-state level. This would also support nationwide adoption of AGC, SCUC, and market-based mechanisms.**

29. **Intra-State SCED and Unified SCUC Framework:** With expansion of market-based

dispatch mechanisms, consideration of Intra-State Security Constrained Economic Dispatch (SCED) and a unified framework for Security Constrained Unit Commitment (SCUC) is essential. Fragmented dispatch mechanisms between inter-state and intra-state systems reduce system optimization and increase overall procurement costs.

Accordingly, it is suggested that **a harmonized and unified framework for SCED and SCUC be developed, integrating intra-state generators progressively to enhance system-wide efficiency.** EAL, IIT Kanpur evaluated alternative market designs using **SCED, MBED, and SCUC models** to assess potential efficiency gains in the Indian power market. The results indicate that expanding SCED participation beyond ISGS to include **SGS and IPPs** increases cost savings, primarily through better utilization of lower-cost generation resources.

A centralized MBED framework, records additional marginal savings in system-wide costs compared with decentralized state-level SCED The magnitude of savings declines further when realistic operational and regulatory factors such as transmission charges, non-linear generation costs, heat rate deterioration, ramping constraints, and incentive mechanisms are incorporated. The SCUC simulations also demonstrate potential efficiency gains, with moderate savings compared to self-scheduling based on unit commitment, while substantial when compared against the economic dispatch model at the state level. Overall, the findings suggest that while centralized dispatch mechanisms can enhance operational efficiency, the net economic benefits are relatively modest and must be evaluated alongside implementation challenges, cost-sharing arrangements, and existing regulatory incentives.

30. **Independent Market Monitoring and Transparency Framework:** With deepening of power markets, including capacity markets and bilateral contract settlement mechanisms, an independent and structured market monitoring framework becomes essential. Market reporting should go beyond publication of transaction statistics and include analytical monitoring of price behavior, bid concentration, and potential market power. Further, summary outcomes of the Market Surveillance Committee of power exchanges should be placed in the public domain to enhance transparency. **A study undertaken by the Centre for Energy Regulation (CER), analysed prevailing framework for market monitoring and the international best practices. It suggested a framework for implementation while considering various aspects including information dissemination and use of tools to enable market data analysis on daily, weekly and monthly basis.** Accordingly, it is suggested that an independent market monitoring mechanism be institutionalized under the Central Commission, with periodic analytical reports to ensure market integrity and consumer protection.[14]

[14] Singh, A., Shivhare, M. and Anand, H., 2025. Market Monitoring Framework for the Indian Power Sector. Kanpur: Centre for Energy
Regulation (CER), Department of Management Sciences, Indian Institute of Technology Kanpur. Submitted to Central Electricity Regulatory Commission (CERC), New Delhi. Supported by FCDO, UK

A Market Monitoring Framework for the Indian Power Sector (Outcomes of a study by CER, IIT Kanpur)

Key Recommendations

- **1. Need of Advanced Market Monitoring Tools:** The Commission may consider the development and deployment of advanced analytical tools for automated assessment of market competitiveness and bidding behaviour in electricity markets.
- **2. Adoption of PROMPT Market Monitoring Dashboard:** The Commission may leverage the Power Sector Regulatory Oversight and Market Performance Tracking (PROMPT) dashboard developed by CER, IIT Kanpur to strengthen real-time monitoring of market performance and participant behaviour.
- **3. Institutionalise Automated Market Reporting:** The regulatory framework may enable automated generation of daily, weekly, and monthly market monitoring reports to support timely regulatory oversight and evidence-based decision-making.
- **4. Continuous Enhancement of Monitoring Tools:** The Commission may encourage periodic enhancement of analytical tools to align with the evolving structure and dynamics of the Indian power market, including increasing participation and new market products.
- **5. Establish an Independent Market Monitoring Unit (MMU):** The Commission may consider establishing an independent Market Monitoring Unit (MMU) responsible for monitoring short-term electricity transactions across all power market platforms.
- **6. Define Governance and Operational Framework:** A clear governance structure, scope, roles, and responsibilities for the MMU should be defined to ensure transparency, accountability, and independence in market oversight.
- **7. Strengthen Data Sharing and Transparency:** The regulatory framework may mandate standardized data-sharing protocols and transparent reporting mechanisms to facilitate effective market monitoring.
- **8. Empower MMU with Data Access:** The MMU should be empowered to seek and access relevant data from all market platforms, exchanges, system operators, and other relevant entities required for market monitoring.
- **9. Reporting and Enforcement Mechanism:** The MMU should report any instances of data non-compliance or potential market manipulation by market participants to the Central Commission for appropriate regulatory action.

31. **Transmission Connectivity and Stranded Asset Risk:** Availability of transmission remains critical to reliable operation of the power system and influences investment in generation. Growing investment in transmission sector with limited competition has also driven costs higher in a regulated environment with significant increases in the per unit transmission cost burden for the end consumers. This is expected to rise even further. The current mechanism for 'guarantee' connectivity to RE plants with minimal financial

commitment has also resulted into significant 'stranded' assets[15]. Absence of sufficient financial stake by the investors should be established, to ensure that the burden of stranded assets does not fall on the consumers.

32. **Deployment and Role of Microgrids:** In the proposed Clause 5.1 (12), *"**Microgrids:** RE-based microgrids must be developed for remote and rural areas and integrated with main grid where feasible."*

    The policy recognises the role of renewable energy based microgrids for remote areas; however, the criteria for deployment of new microgrids and the treatment of existing mini-grid systems require further clarity.

    Microgrids should preferably be deployed in areas where grid extension is uneconomical due to difficult terrain, seasonal inaccessibility, or extremely high infrastructure costs. Additionally, clear regulatory provisions should be developed for the treatment and integration of existing mini-grids once the main grid arrives, including tariff arrangements and asset utilisation.

    In disaster-prone regions and geographically remote areas, resilient microgrids may be considered as a primary source of electricity supply for critical infrastructure such as healthcare facilities, emergency services, and agricultural extension centres.

33. **Transmission-optimised Siting of Renewable Energy Projects:** The policy suggests that renewable energy projects should preferably be located near load centres to optimise transmission costs. **The overall economics of harnessing RE should be guided by the resource intensity as well as the applicable transmission cost and losses thereof.** Solar energy can be harnessed with decent capacity utilisation factor across most of the states. **Choice of multiple geographically dispersed sites for RE procurement** also avoids the risk of widespread cloud cover affecting solar energy generation or significant localised variation in wind intensity. This should be weighed against deployment of economic storage in terms of overall economics and reliability. **Long-term RE integration modelling using optimisation approach may help discoms discover a reasoned answer to this question.**

34. **Coal Supply Chain Readiness and Coordination:** Coal-based thermal power plants face significant challenges related to the readiness of the coal supply chain, including issues related to coal availability, transportation infrastructure, coal quality, and contractual arrangements. These challenges adversely affect the cost competitiveness of coal-based electricity generation. Coal quality not only affects the economics of producing electricity but also operationally affects the generating units. NEP may propose a detailed roadmap, in coordination with the Ministry of Coal and Ministry of Railways for **coal supply chain**

[15] CERC (2025), "Staff Paper on Proposal for allocation of Connectivity granted (on LOA route) where the signing of the PPA/PSA is getting delayed", https://cercind.gov.in/2025/staff-paper/SP-251125.pdf

monitoring from the mine seam to the delivery station at the power station with traceability of wagon wise source. This would also ensure that the coal sampling for quality assessment is not compromised as multiple sampling would help ascertain source wise and customer wise quality differential that can be either linked to the quality at source or that that deteriorated during the transportation. **AI-based tools incorporating GPS based data to analyse the pictorial inputs captured at multiple locations across the supply chain.** This investment would pay for itself as it would help address coal leakage and quality degradation thus reducing final cost to the generating plants and the final consumers.

To address the coal quality issues and implement the suggested solutions, **a joint working group comprising senior officials from the Ministry of Power, Ministry of Coal, and Ministry of Railways may be constituted.** This would also help to identify supply chain bottlenecks, transportation constraints, and contractual/payment issues affecting coal supply.

35. **Flexibility Requirements in Thermal Power Plants:** Increasing penetration of renewable energy in the power system places greater demand for flexibility from power system constituents, including conventional generators and demand-side resources. **Investments in flexibility should be evaluated in terms of its economics vis a vis alternate solutions (such as demand response, storage etc.) to enhance flexibility of the power system.** Two specific interventions in the context of coal-based thermal power plants – (i) Minimum Technical limit (MTL) (ii) Ramp rate need to be evaluated on their own merit. While some units may need intervention of the first kind, the others may need to focus more on the second one. **A study may be undertaken to evaluate relative merit of such investments vis a vis implementation of demand response and economically viable energy storage.**

The CEA (Flexible Operation of Coal-based Thermal Power Generating Units) Regulations, 2023 mandates that coal-fired power plants reduce their minimum technical load (MTL) to 40% to accommodate high renewable energy integration by 2030. Retrofitting majority of the existing coal-based power plants for flexible operation may significantly increase the cost of power procurement for distribution licensees and ultimately for consumers. **Phased flexibility investment should therefore be prioritised for marginal (i.e. those with high energy charges) plants that hit the MTL or the ramp limit. Plants reaching near their end of life should not be a candidate for such investment. Alternate and more economical options should be exercised to bring about greater flexibility in the power system.**

It is also important to note that enhanced flexibility operation may increase the variable cost of certain plants, which could affect their position in the merit order**. The additional energy cost for incremental flexibility may therefore be recoverable separately including through market-based procurement of flexibility services and should not affect the merit order.** This would ensure that the sector adopts a **technology-neutral ap[proach to promote power system flexibility.** This would then require that RoE incentive provided in

the CERC's Terms and Condition for Tariff be discontinued else this would result in double cost burden on discoms.

36. **Utilisation of Steam for District Cooling:** The draft proposes utilisation of steam generated from thermal power plants for district cooling applications. Such utilisation effectively falls under the broader framework of cogeneration and may improve the overall thermal efficiency of the system.

    If district cooling is undertaken for captive purposes, it may not pose regulatory concerns. However, where chilled water is supplied to third parties, appropriate contractual arrangements and regulatory clarity would be required. In such cases, the regulatory framework for tariff determination of electricity generated from such cogeneration plants should consider the improved overall efficiency achieved through simultaneous delivery of electricity and cooling services.

    Such systems may also find potential applications beyond conventional urban cooling clusters. For instance, cogeneration plants may provide both electricity and chilled water to energy-intensive facilities such as data centres located in proximity to thermal plants.

37. **Blending of Alternative Fuels in Thermal Power Plants:** The policy suggests incorporation of alternative fuels such as biomass and municipal solid waste in thermal power plants. The experience of biomass co-firing should be comprehensively evaluated in terms of its net environmental and economic impact.

    Procurement of biomass for co-firing often faces challenges related to lack of competitive markets, limitations in aggregation mechanisms, and issues in monitoring calorific value and quality through third-party sampling[16].

    Accordingly, greater clarity and empirical assessment of the outcomes of biomass co-firing initiatives may be required, including regulatory provisions governing cost recovery and quality monitoring.

[16] An ongoing research at IIT Kanpur identified some of the supply chain related issues.

38. **Life Extension and Investment Evaluation:** Modernisation and efficiency improvement of thermal power plants nearing the end of their life under a regulated cost environment should only be undertaken if the overall cost of such investment is competitive with new capacity over the remaining and extended life of the project. This decision should be an outcome of the resource adequacy exercise that makes due consideration of the overall cost of power procurement for the discom. **Flexibility of the candidate thermal generation (for life extension) should be an additional criteria while evaluating such investment.**

    Accordingly, **evaluation of life extension proposals should be undertaken as an integral part of the resource adequacy exercise,** at least 7–8 years in advance, enabling beneficiaries to assess the economics of extending existing PPAs versus procuring new long-term capacity through alternative technological choice. In such cases, the first right of refusal should remain with the beneficiaries who have borne the capacity charges of such plants over their entire operational life.

39. **Institutional Mechanisms for Coal Quality Assurance:** The policy states that coal suppliers should assume responsibility for coal quality on an "as-delivered" basis to mitigate generation losses arising from grade slippage. **The policy should also provide guidance for the institutional or contractual mechanisms enforcing the same.**

    In practice, ensuring accountability for coal quality may require stronger risk-sharing arrangements between coal suppliers and thermal power plants. **One possible (theoretical) approach could involve swapping a limited amount of the equity stake between the coal supplier and the thermal generating companies** thereby aligning incentives and ensuring greater responsibility for quality of coal supplied. While proposal carries its own implementation challenges, it would be a **credible hedging mechanism for the inherent risk across the supply chain.**

40. **Utilisation of Fly Ash:** With the addition of more than 90 GW of coal-based generation capacity, fly ash generation is expected to increase significantly. This would require urgent and advanced measures to ensure utilisation of fly ash from the Date of Commercial Operation (CoD) of new plants. The MoP guidelines, issued in March 2024, may be converted to a mandate through stakeholder consultation. **A National Fly Ash Mission, mandating commercial utilisation of fly ash in the construction sector, may be initiated through the policy.** The policy should mandate a framework for monitoring and compliance associated with fly ash generation, transportation, storage, utilisation and disposal thereof.

41. **Voltage Support and Grid Inertia:** The policy proposes repurposing inefficient thermal plants as synchronous condensers for providing voltage support and grid inertia. **The policy may propose pilot studies, by Grid Controller of India Ltd., to evaluate the techno-economic feasibility of converting retired thermal units into synchronous condensers and to assess the potential benefits in terms of ancillary services and system stability, and associated cost thereof.**

42. **Hydropower Development and Cost Escalation Risks:** Hydropower projects can play an important role in India's energy transition and diversification of the energy mix. However, significant project delays and cost escalations often make such investments less competitive compared to other technologies.

    Under the existing regulatory framework, a substantial portion of project risks, including cost overruns, are passed on to beneficiaries and ultimately to consumers. While regulated returns continue to incentivise investment, developers may not bear sufficient accountability for delays attributable to project management.

    Accordingly, the return on equity for hydropower projects should be linked to timely completion of projects, and developers may be required to share part of the risks associated with delays attributable to their project management practices.

43. **Climate Resilience for Hydro Generation:** The policy recognises the role of storage-based hydropower projects in flood moderation, irrigation and energy security. However, while hydropower projects may contribute to climate adaptation, their own **resilience to climate risks especially hydrological variability also needs to be addressed.**

    Appropriate measures may therefore be considered to assess and strengthen the climate resilience of hydropower projects, particularly given their long operational lifetimes. **The policy may provide for a multi-institutional study to evaluate climate risks for the hydro power plants.**

44. **Resource Adequacy:** In the proposed Clause 3 (3) *"**Resource Adequacy Plans (RAPs):** CEA, in consultation with relevant State Government departments and key stakeholders, will prepare national-level RAPs for generation and transmission, ensuring adequate reserve margins and grid reliability. SLDCs and distribution licensees will prepare State and distribution utility level RAPs, aligned with national plans. Regulatory commissions will frame supporting regulations."*

    Multiple aspects are emphasised here in the context of the RAP.
    - **Optimising long-term RAP** – The RA plans do not disclose an assessment of the

projected cost of power procurement under alternate and the suggested plan. This is not in line with the spirit of the Electricity Act 2003, which clearly mandates economy in conduct of the procurement

- **RA by grid interactive loads** – Apart from the distribution licensees, RAP needs to be emphasised for entities with captive generation and those with long-/medium-term open access.
- **Planning and operative reserve margin -** Apart from the distribution licensees, entities with captive generation and those with long-/medium-term open access should also provide for planning as well as operating reserve. In its absence, the cost burden for distribution licensees and is customers would be higher.

The planning framework should incorporate state-specific and DISCOM-specific factors, including appropriate planning reserve margins, to ensure reliable and economically efficient resource procurement aligned with local system conditions.

45. **Competitive Bidding for Transmission Infrastructure:** In the proposed Clause 8.4 (1) *"Competitive bidding shall be the default mode for all inter-, and intra-state transmission projects. State-owned Transmission licensees may also be encouraged to participate in such bidding. Exceptions may be permitted only for urgent, strategic or technically critical projects in accordance with the framework prescribed by the Appropriate Government."*

    In cases where exceptions to competitive bidding are permitted for urgent, strategic, or technically critical transmission projects, the **Swiss Challenge approach** may be considered to ensure adequate competition and transparency in the selection process. Such an approach would help maintain competitive efficiency while facilitating timely development of transmission infrastructure of strategic importance.

46. **Uniform Compensation Framework for Transmission Corridors:** The clause provides for compensation mechanisms for land value in transmission corridors and optimisation of right-of-way corridors.

    A uniform compensation framework may be considered for both inter-state and intra-state transmission networks to ensure consistency and fairness in compensation for land value diminution associated with transmission corridors.

47. **Transmission Planning for Emerging Non-Fossil Energy Projects:** The clause proposes proactive development of transmission infrastructure for non-fossil generation and demand zones, including dedicated green feeders.

    Recent developments in green hydrogen projects have generated considerable enthusiasm and have led to the creation of transmission infrastructure in anticipation of project development. However, in several instances delays or non-implementation of such projects

have resulted in stranded transmission assets, placing financial burden on the end consumers.

While promoting non-fossil energy sources, transmission planning and infrastructure development should be undertaken with adequate safeguards to avoid stranded assets. **Any policy enabling proactive development of transmission infrastructure should be supported by firm commitments and upfront financial assurances from project developers to ensure that distribution licensees and end consumers do not bear the burden of underutilised transmission infrastructure.**

48. **Cross-Border Electricity Trade and Interconnections:** In the proposed Clause 8.6 (3) *"*Cross-*border interconnections shall be strengthened under the overall vision of One Sun One World One Grid (OSOWOG). India will actively promote the cross-border exchange of renewable energy to support regional energy transition efforts. Harmonised regulations shall be developed to facilitate cross-border electricity trade, and India will play a leadership role."*

    Cross-border interconnections can enhance India's ability to integrate and absorb a higher share of renewable energy and strengthen the country's energy security. However, such interconnections should be pursued based on technology readiness and overall project economics.

    In particular, projects involving subsea cables, which require significant capital investments, should be carefully evaluated against alternative options such as energy storage technologies and demand response mechanisms to ensure cost-effective system planning.

49. **Distribution Sector Sustainability and Market Competition:** In the proposed Clause 9, *"Distribution is the most crucial part of the power sector directly serving consumers and generating revenue for the entire sector. The Central and State Governments as well as Regulators shall ensure the financial sustainability of the distribution sector, and undertake the following measures:"*

    and in the proposed Clause 4 (5), "***Building a Competitive Market:*** *Competition across the power sector must be promoted to benefit consumers. Currently, distribution licensees are obligated to supply power to manufacturing industries and railways, even if these consumers are capable of sourcing power independently. This compels DISCOMs to contract power for such consumers, leading to underutilization and fixed cost burdens. To recover these costs, State Commissions impose high cross-subsidy and surcharges, raising industrial tariffs and reducing competitiveness. The Act allows generators and traders to directly supply electricity to consumers under Open Access, and State Commissions must not stifle competition with cross-subsidy and additional surcharges.* ***It is suggested that Regulatory Commissions, in consultation with Appropriate Governments, may exempt the distribution licensees from the Universal Service Obligation in respect of consumers having a***

contracted load of 1 MW and above, capable of self-procurement. State Commissions should exempt manufacturing enterprises, Railways, and Metro Railways from payment of cross-subsidies and surcharges. *These measures will ensure that Indian goods remain competitively priced, cost of logistics is optimized and commuting costs of workforce come down. Regulatory Commissions should create appropriate frameworks to enhance market liquidity and ensure availability of power at competitive prices.*" (emphasis added)

Clause 9 emphasises the need to ensure financial sustainability of the distribution sector. However, the provisions under Clause 4(5) proposing exemption of large consumers (≥1 MW), manufacturing enterprises, Railways and Metro Railways from cross-subsidies and Universal Service Obligation may be inconsistent with this objective. As highlighted earlier, cost associated with energy/electricity purchase constitutes a miniscule proportion of such consumers for the electricity purchased from the discom. In case of energy intensive industries, such consumers have limited dependence on discoms due to substantial captive generation capacity. (see discussion above based on energy cost data across key sectors)

Large industrial and commercial consumers constitute a significant revenue base for DISCOMs. Their migration through without cross-subsidy contributions would adversely impact the financial viability of distribution utilities. While improving DISCOM performance is essential, such improvements would be further delayed with loss of cross-subsidising consumers.

Accordingly, a **balanced and phased approach may be considered to ensure that promotion of competition and open access does not undermine the financial sustainability of DISCOMs during the transition period.**

50. **Cost Optimisation and Market Participation:** In the proposed Clause 9 (1*), "**Cost Optimisation:** Appropriate Commission should provide distribution licensees enough freedom to take timely, market-based decisions for power purchase to ensure reliable and good quality supply. Efficient energy portfolio management should be encouraged to reduce power purchase costs. Training programmes will be introduced to help utility staff build the skills needed to manage market operations."*

While providing distribution licensees with greater flexibility to undertake market-based procurement decisions, adequate regulatory safeguards should be ensured. Capacity building through structured training programmes is essential to enable effective participation in evolving electricity markets. **Availability of sufficient human resources for key commercial functions including market-based procurement with discoms and with the SLDCs is critical to enable them to take informed decision with sufficient <u>in-house capability.</u>**

Such training programmes should include load dispatchers, DISCOM personnel and

regulatory commission staff, and should cover technical, operational, financial and regulatory aspects of power market operations. These programmes may be delivered through online platforms to ensure wider accessibility and continuous skill development.

51. **Competition and PPP in Distribution: Carriage and content separation remains international gold standard for introducing retail supply competition. Multiple distribution licensee may not only lead to over investment (and hence high cost to the discom) but also open up multiple avenues for disputes on account of a variety of legal, technical and operational challenges.** In fact, apart from Mumbai, there are no examples of scale to demonstrate efficacy of the model across the world. Issues such as network connectivity, energy accounting and settlement mechanisms may become complex and may create larger scope for disputes among competing retailers.

    Accordingly, introduction of retail supply competition should be initiated as a pilot across selected distribution license areas providing regulatory template for further finetuning while comparing alternate models for introducing the same.

52. **A Business Sandbox Approach to PPP:** Public private partnership (PPP) models can be suitably designed for identified business segments of a distribution licensees with clearly identified baseline, performance target and incentive/penalty structure with transparent performance measurement and compliance framework.

    The distribution network in an identified area of the distribution licensee is handed over to an O & M operator through PPP (BOT or BOOT route for example) model based on reverse (competitive) bidding with benchmark[17] average O & M cost as per recent regulatory approval with adjustment for load density, asset quality, consumer mix, desired standard of performance (SoP) etc.

53. **Asset securitisation and Listing of government companies:** The power sector offers numerous avenues for unlocking the value in the generation, transmission and distribution assets across the country. While remaining dominantly government owned, such public listing can help raise financial resources while also enabling the respective state government to use the listing proceeds from partial sale of its equity for infusing capital in the laggard segments of the sector in the respective state.

    Carriage and content separation, even without introduction of retail supply competition, can offer opportunities for asset monetisation of the distribution licenses. This would further enable some of the distribution licenses to enable their listing. Network business, which is inherently less risky (and hence has lower beta[18]), and is

[17] Benchmarking methodologies such as data envelopment analysis and stochastic frontier analysis can be used to set such benchmarks.

[18] Kewal Singh, Anoop Singh, Puneet Prakash, 2022, "Estimating the cost of equity for the regulated energy and infrastructure sectors in India" *Utilities Policy*, http://dx.doi.org/10.1016/j.jup.2021.101327

relatively less exposed to political decision-making, remains a preferred candidate for unlocking the asset value in the sector across the states.

54. **Adoption of New Technologies:** New technologies should be adopted only after proper technical and economic evaluation. It should be demonstrated that the investment leads to measurable savings or operational improvements.

    Further, after implementation, it should be assessed whether the benefits realised are actually attributable to the technology or due to other system improvements. Since stakeholders may have different perspectives regarding technology adoption, their participation and buy-in[19] should be ensured by clearly demonstrating the expected benefits.

55. **Smart Grids and Smart Metering:** Investment in smart metering infrastructure has potential benefits enabling improvement in operational as well as financial performance of the discoms. **Apart from billing and collection (in case of pre-paid meters), the smart meter data provides useful insights for tariff design, and design and implementation of demand response program.** However, it is observed that apart from billing and collection, **value of the smart metering infrastructure has not been unlocked in a desirable manner.** In fact, access to such data remains limited to support meaningful research relevant in the Indian context.

    In the absence of a regulatory framework for cost–benefit analysis, consumers continue to bear the cost of new technologies which may or may not add value to the electricity sector and the end consumers. Techno-economic impact assessment of the smart metering investment across discoms should be undertaken to enable the regulators to take decision for further investment and built necessary safeguards ensuring unlocking value of the investment thus also safeguarding consumer interest.

56. **Automation of Distribution Infrastructure:** Automation of distribution infrastructure may be explored through PPP models. Private investors may be allowed to invest in substation automation and related technologies which could improve standard operating procedures and operational efficiency.

    The business case for such investment may be based on savings in operational cost and other measurable benefits, especially in terms of improvement in standards of performance (SoP) for which the consumer also have willingness to pay additional charge linked to SoP. The resultant sharing of savings and incentives for SoP would create a business case for private sector participation. In addition, distribution transformers may be treated as business centres, enabling targeted technological interventions and loss reduction through private sector expertise.

[19] Brijesh Bhatt, Anoop Singh (2021), "Power Sector reforms and technology adoption in the Indian electricity distribution sector", Energy, Elsevier, Volume 215, Part A, 15 January 2021.
https://www.sciencedirect.com/science/article/pii/S0360544220319046

57. **Digitalization and Smart Infrastructure:** Digitalization of the power system is important, given the ongoing technological development and the need for enhancing visibility of the grid for improved performance. Digitalization initiatives involve significant investments and also pose challenges such as technological obsolescence and interoperability issues. Therefore, decisions regarding greater digitalization of the distribution segment should be based on an objective evaluation of cost–benefit analysis, institutional readiness, and stakeholder buy-in to ensure that the expected benefits of digitalization are effectively realised.

58. **Advanced Technologies for Grid Stability and Creation of Distribution System Operator:** Integration of distributed renewable energy resources involves deployment of technologies such as smart inverters, vehicle-to-grid systems and advanced control mechanisms. Effective management of such distributed resources would require real-time monitoring and operational coordination at the distribution network level.

    Accordingly, it is suggested that within the existing organizational structure of the distribution licensees, **the system operation function of the distribution network should be segregated and developed as a dedicated operational unit. Over time, the creation of a Distribution System Operator (DSO) may be considered**, similar to system operation arrangements in the transmission sector. Such an institutional arrangement would help improve real-time network management and enhance operational efficiency of distribution network. **DSO would also facilitate greater RE integration, demand response and introduction of retail supply competition in the sector.**

59. **Undergrounding of Distribution Networks:** The draft policy suggests undergrounding of distribution networks in congested urban areas to enhance reliability of supply. Undergrounding of distribution networks involves very high capital costs and its implementation may be particularly challenging due to right of way (RoW) issue in areas where integrated utility corridors and urban planning frameworks are not well developed.

    Accordingly, undergrounding of distribution networks should preferably be undertaken only where it forms part of an integrated urban infrastructure planning framework such as smart city development initiatives or where reliability considerations justify the additional costs. **Such additional cost should not be socialised across all the consumers in the area of the distribution licensee.** Regulatory approach should be to recover such additional cost through tariff from consumers benefiting from such investment. This would also test necessary buy-in from the consumers to benefit from such initiatives.

60. **Strengthening Corporate Governance of Distribution Utilities:** The policy proposes strengthening corporate governance in distribution utilities through inclusion of external power sector experts on boards of distribution licensees.

The distribution utilities should ensure presence of the required number of independent directors on their board in accordance with the provisions of the Companies Act. Strengthening board-level governance would improve transparency, accountability and decision-making across the distribution utilities.

61. **Universal Access to Electricity and Unwilling Households:** The policy recognises that India has achieved universal electrification of willing households. However, the concept of "willing households" requires further examination to ensure that electrification statistics accurately reflect ground realities.

    Accordingly, an initiative may be undertaken to identify households that 'choose' to remain unelectrified and understand the reasons for their unwillingness to take electricity connections. Such analysis would help determine whether the issue relates to affordability, service quality, or other socio-economic factors, and would enable targeted interventions to ensure inclusive access to electricity.

62. **Consumer Choice in Electricity Supply and Consumer Protection:** The policy emphasises offering consumers choices in electricity supply and usage. Consumer choice may be introduced through mechanisms such as retail supply competition enabled through carriage and content separation. Retail supply competition would not automatically bring benefit to the consumers unless they are **empowered to take informed decision in terms of their choice amongst the alternative tariff plans and the associated conditions**. This would require consumer empowerment through information sharing, and protection of their interest. **Strengthening of the complaint redressal and dispute resolution process** including its access and speed of resolution, and monitoring would be of paramount importance for protecting consumer interest.

63. **Strengthening Consumer Grievance Redressal Mechanism:** The existing consumer grievance redressal mechanism involves multiple stages including Consumer Grievance Redressal Forums (CGRF) and the Ombudsman. However, the absence of an integrated complaint tracking system makes it difficult to analyse the lifecycle of consumer complaints.

    Accordingly, a unified complaint numbering system may be introduced across the state enabling tracking of complaints from CGRF to the Ombudsman level. Such a system would enable regulators to analyse complaint patterns, identify systemic issues and improve the overall grievance redressal process.

64. **Framework for Defining and Reporting Quality of Supply Parameters:** The draft policy proposes monitoring and publication of quality of supply parameters such as reliability indices. In case of telecom sector, the Telecom Regulatory Authority of India (TRAI) periodically publishes quality of service reports across various segment of services in the

telecom sector. A unified framework (through a national portal) would not only bring transparency, empower consumers, bring accountability, and enable better compliance by the regulatory commissions.

The national-level framework should outline key definitions, measurement protocol, reporting and archiving of quality of supply parameters to ensure consistency across the country. Such standardisation would reduce definitional ambiguities and improve transparency and comparability of performance indicators across distribution utilities.

65. **Monitoring Service Quality and Third-Party Verification:** The policy proposes monitoring of service quality indicators and public disclosure of reliability indices. While such transparency is important, independent verification mechanisms are also necessary to ensure credibility of reported data. Telecom sector provides a credible example of adoption of third party for quality of service monitoring. Data analytics of consumer complaints would also offer insights to the quality of service.

    Accordingly, third-party sampling-based quality monitoring mechanisms may be introduced to verify service quality data reported by distribution utilities. A framework similar to the monitoring mechanism adopted by the TRAI may be considered for independent verification of service quality parameters.

66. **Enhancing Consumer Participation in Regulatory Proceedings:** Consumer participation in the regulatory proceedings remains limited, particularly for domestic, agricultural and small commercial consumers. While large consumers and industry associations are often able to represent their interests effectively, smaller consumers lack the resources and technical expertise to participate in the regulatory processes.

    An institutional mechanism may be developed to support consumer representation in regulatory proceedings, including **creation of consumer support institutions that can analyse tariff petitions and represent consumer interests in proceedings related to generation, transmission and distribution tariffs and other regulatory matters.**

    Establishment of consumer education centres or similar institutional arrangements may help support consumer participation in regulatory processes and ensure that consumer interests are adequately represented in sectoral decision-making. International experience with institutional mechanisms to safeguard consumer interest provides multiple examples across US, Australia as well as Europe. **Region/state specific institutional initiatives, supported with very small 'regulatory levy' in tariff can help support the interests of small consumers across domestic, agricultural, commercial and industrial categories.**

67. **Promotion of Energy Efficient Appliances:** The policy suggests that distribution licensees

may support adoption of energy-efficient appliances and rooftop solar installations with storage. **Price based instruments are best suited for enabling technology adoption. This needs to be supported with conducive regulatory and policy environment. Following approach to price-based signals may be adopted to incentivise adoption of storage with behind the meter solar installations.**

- Time of Day (ToD) consumer tariffs
- Net metering regulation with ToD sensitive net metering/net billing/gross metering etc.
- Demand Response Program (Aggregator-based)

Apart from this higher PV capacity may be allowed for consumers with certain minimum proportion of storage.

Energy efficiency initiatives should be implemented in collaboration with the Bureau of Energy Efficiency through established programmes promoting energy-efficient appliances. **Based on normative energy saving potential, equivalent energy saving certificates (EScerts) may be issued/deemed to accrue for purchase of energy efficient appliances. Monetisation of such certificates through a manufacturer led scheme can help bring down the cost of energy efficient appliances for the consumers.**

In addition, demand-side management programmes such as **smart air-conditioning technologies** capable of minor temperature adjustments during low frequency high demand periods may also be explored to manage peak loads without significantly affecting consumer comfort.

68. **Separation of Distribution Network Operation (DNO) and Distribution System Operation (DSO):** The experience from the unbundling of transmission functions—namely transmission network ownership, transmission system operation and planning for the interstate network—has clearly demonstrated the benefits of separating these functional areas. Such separation has improved transparency, operational neutrality and non-discriminatory access to the network.

    Integration of distributed renewable energy resources involves the deployment of technologies such as smart inverters, vehicle-to-grid systems and advanced control mechanisms. Effective management of such distributed resources requires real-time monitoring and operational coordination at the distribution network level. The evolving nature of the power sector, particularly the possible emergence of retail supply competition in the future, the presence of an independent system operator at the distribution level would become increasingly important. **An independent Distribution System Operator (DSO) would ensure non-discriminatory system operation, transparent grant of open access and efficient planning of distribution networks.**

As an initial step, this transition may begin through **organizational separation of DNO and DSO within the existing distribution utilities**, including separation in terms of manpower, workflows, decision-making structures and financial accounting. S**uch functional separation would lay the foundation for eventual institutional unbundling of DNO and DSO. A distribution license area may have multiple DNOs but a single DSO, thus reducing the scope of disputes in the presence of multiple distribution licensees.**

In addition, it would help clearly assign responsibility for maintaining distribution system performance standards as prescribed by the respective State or Joint Electricity Regulatory Commissions.

69. **Data Accessibility from System Operators:** Transparency and accessibility of operational data play a critical role in improving system operation, enabling analytical research and facilitating evidence-based policymaking in the power sector. In the context of system operation, Load Dispatch Centres (LDCs) serve as key repositories of operational data such as declared capacity, generation schedules, injection levels and other grid parameters.

    While some LDCs proactively share such information through real-time dashboards and archival portals, it has been observed that several LDCs either do not make this data readily accessible or provide it in formats such as scanned images. Such formats significantly limit the usability of the data for analytical, regulatory or research purposes. **In the absence of data in the Indian context, research by researchers in India is often focussed on other countries whose data is easily available through online resources. This highlights a new kind of brain drain.**

    To ensure greater transparency in grid operations and enable adoption of best international practices, the policy may encourage LDCs to share operational data in **machine-readable formats** and maintain **structured archival repositories** for historical datasets. **Such data may also be released with a delay of 1-2 days to address any concerns about its inappropriate use.**

    Improved accessibility of grid operational data would enable regulators, policymakers, researchers and other stakeholders to undertake meaningful analysis, improve forecasting methodologies and enhance overall efficiency and reliability of the power system.

70. **Need for Structured Data Governance in the Power Sector:** With increasing digitalisation of the electricity sector, large volumes of data are generated across various stages of the electricity value chain. This includes data related to generation, transmission operations, distribution networks, consumer usage patterns and system planning activities. However, the **absence of a comprehensive data governance framework often results in inconsistencies in data definitions, formats and reporting practices across sector**

entities.

The policy may therefore consider introducing a **dedicated data governance framework for the power sector**, covering the entire data lifecycle including generation, measurement, processing, storage, retrieval and utilisation. Standardised definitions, reporting templates and data formats would significantly improve data reliability and comparability across institutions.

Improved access to high-quality datasets would also support analytical research and policy development. Currently, many researchers in India working on technical, operational and economic aspects of the power sector often rely on international datasets or outdated domestic data due to limited access to current operational data across the electricity supply chain.

Enhancing transparency and structured access to datasets would strengthen analytical capability within the country and support evidence-based decision-making for regulators, utilities and policymakers.

71. **Facilitating Data Sharing Across Power Sector Institutions:** Despite the availability of large volumes of operational data within the power sector, several entities remain reluctant to share such data due to concerns related to regulatory clarity, legal liabilities and operational constraints. In many cases, utilities cite lack of clear protocols for data sharing, absence of manpower for data retrieval, or concerns that increased transparency may expose operational inefficiencies.

    To address these challenges, the policy may encourage the development of **standardised protocols for data sharing across the power sector**, **including a common Non-Disclosure Agreement (NDA) framework.** Such a standardised NDA template could be developed in consultation with sector stakeholders including utilities, regulators, consultants, academic institutions and legal experts.

    The availability of a common NDA framework would enable utilities to share data with researchers and other stakeholders while ensuring appropriate safeguards for confidentiality and data security.

72. **Strengthening Cybersecurity Protocols for Power Sector Infrastructure:** With increasing digitalisation and integration of information technology systems into power sector operations, cybersecurity has become a critical concern for system operators and utilities. In particular, the distribution network and system operation infrastructure are increasingly dependent on communication systems, digital control technologies and data networks.

The cybersecurity preparedness of power sector entities, especially the distribution utilities, remains weak/uneven. The absence of standardised protocols and compliance mechanisms may expose critical power sector infrastructure to cyber risks.

The policy may therefore encourage the development of **standard cybersecurity protocols for the power sector**, including clearly defined compliance requirements and reporting frameworks. These protocols may be developed by the Central Electricity Authority in consultation with relevant stakeholders, including power utilities, cybersecurity agencies and technical experts.

The framework may include periodic compliance reporting, clear institutional responsibilities and mechanisms for timely reporting of cybersecurity incidents. Establishing structured cybersecurity governance would help improve resilience of power system infrastructure and ensure secure operation of increasingly digitalised power networks.

73. **Improving System Visibility of Emerging Distributed Resources:** The rapid growth of distributed energy resources such as rooftop solar and electric vehicle charging infrastructure is expected to significantly influence electricity demand patterns and distribution network operation. However, obtaining real-time visibility of all distributed resources may not be practically feasible and cost effective due to the large number of small installations distributed across the licensee area.

    A more practical approach may involve capturing operational data for larger installations while aggregating information from smaller resources on sampling basis. At the same time, operational data generated by smart meters, inverters and charging infrastructure should be **archived within the country** and made accessible for system planning purposes.

    Due to rising energy security concerns, electric vehicle charging demand is expected to become an important component of electricity consumption in the future. Encouraging **separate metering for electric vehicle charging (except 2 wheelers)**, could provide valuable data for forecasting demand growth and planning distribution network upgrades.

    Such visibility would also enable future integration of electric vehicles into **vehicle-to-grid (V2G) and grid-to-vehicle services**, thereby supporting demand response and providing flexibility resources to the power system.

74. **Collaborative Approach for Sectoral R&D Initiatives:** The policy proposes that power utilities earmark financial resources for research and development activities. However, many distribution utilities face significant operational and financial constraints, which may limit their ability to independently undertake large and multiple research initiatives.

A more effective approach may involve **collaborative R&D initiatives involving multiple utilities, generators, system operators and academic institutions**. **Joint research programmes would allow participating entities to pool financial resources, technical expertise and operational experience.**

Such collaborative efforts would also enable testing of innovative solutions across multiple operating environments. For instance, demand response mechanisms, digital tools for distribution system planning or advanced forecasting models could be piloted across different states, generating valuable insights and practical use cases.

75. **Balanced Approach to Domestic Manufacturing and Technology Deployment:** Promoting domestic manufacturing and technology development in the power sector is important for strengthening energy security and reducing dependence on external supply chains. Initiatives such as domestic equipment manufacturing and technology development can support long-term self-reliance in critical power sector technologies.

    At the same time, it is important that such initiatives are implemented within a **competitive ecosystem** that ensures cost efficiency and technological innovation. Excessive protection without sunset clause may lead to higher costs for utilities and ultimately for electricity consumers.

    The policy may therefore consider adopting a **graduated or time-bound approach with sunset policy to promote domestic technology/manufacturing**, where domestic manufacturers receive initial support while gradually achieving competitiveness in open markets. Such an approach would encourage technology development while maintaining efficiency in procurement decisions.

76. **Strengthening Regulatory and Institutional Governance:** The policy emphasises technological and structural reforms across the power sector but provides relatively limited attention to strengthening institutional governance frameworks. Effective implementation of sector reforms requires **strong regulatory institutions and well-trained personnel across utilities, system operators and regulatory commissions.**

    In particular, there is a need to enhance professional capacity within institutions such as load dispatch centres, distribution utilities and regulatory bodies. **There is an urgent need to increase the sanctioned strength of employees, particularly for key techno-commercial-regulatory functions across the electricity sector especially the regulatory commissions and the load despatch centres.** The policy may therefore encourage the development of structured **capacity-building programmes and professional training frameworks** for personnel involved in system operation, regulatory oversight and sector planning.

    Establishing dedicated professional cadres for key operational roles, including load

dispatchers and regulatory professionals, may significantly strengthen institutional capacity and improve governance within the sector.

Enhanced institutional capacity would also improve monitoring of compliance, implementation of regulatory frameworks and adoption of modern operational practices necessary for managing a rapidly evolving electricity system. **Strengthening institutional capacity would therefore play a critical role in ensuring that technological and regulatory reforms in the power sector are implemented effectively.**

77. **Optimising Financing Cost for Power Sector Entities:** The power sector requires substantial financial investments to support network expansion, renewable energy integration, digitalisation and infrastructure modernisation. However, the availability and cost of financing remain significant constraints for many utilities, particularly state-owned generation, transmission and distribution companies.

    The policy should therefore encourage utilities to adopt **competitive and diversified borrowing strategies**, enabling them to access financing at lower interest rates where feasible. In several cases, private sector utilities have demonstrated the ability to access debt at rates close to sovereign borrowing levels, whereas many state government owned utilities continue to incur significantly higher borrowing costs.

    Optimising the cost of borrowing for original debt or its restructuring later can substantially reduce the overall cost of infrastructure investments and ultimately lower electricity tariffs for consumers. Encouraging greater financial discipline and competitive financing mechanisms would therefore strengthen the financial sustainability of the power sector.

78. **Exploring Green Finance and New Financial Instruments:** The scale of investment required for modernising the power sector and supporting the energy transition necessitates the exploration of innovative financing mechanisms beyond conventional lending structures. Traditional project financing may not always be sufficient to support emerging technologies and infrastructure projects associated with renewable integration and grid modernisation.

    In the above context, the policy may consider promoting use of **innovative financing structures such as green finance instruments, climate finance mechanisms and contract-for-difference (CFD) based frameworks**. Such instruments could help reduce financing risks for investors while supporting the development of new technologies and infrastructure required for the evolving electricity system.

    Green finance mechanisms may also facilitate access to international capital markets, enabling utilities to raise funds for projects that contribute to decarbonisation and sustainability objectives. Successful implementation of such mechanisms would require

clear regulatory frameworks, transparent financial reporting and improved financial discipline within sector entities. Strengthening the financial governance of utilities will therefore remain an essential prerequisite for attracting long-term investment into the power sector.

79. **Enhancing Resilience of Electricity Networks to Climate Events:** Extreme weather events such as floods, storms and cyclones increasingly pose risks to electricity infrastructure across various parts of the country. In several regions, particularly in river basins and coastal areas, distribution networks have experienced significant damage during such events, affecting power supply reliability and increasing repair costs.

    While the policy discusses broader climate adaptation measures, the resilience of electricity infrastructure itself requires greater attention. Distribution networks are particularly vulnerable due to their extensive geographic spread and exposure to environmental conditions.

    The policy may therefore encourage utilities to incorporate **climate resilience considerations in network planning and infrastructure design**, including adoption of technologies and construction practices that reduce vulnerability to extreme weather events. Improving resilience of distribution infrastructure would not only reduce the economic impact of infrastructure damage but also enhance reliability of electricity supply during emergency situations. Strengthening the resilience of power networks will therefore become increasingly important in the context of evolving climate risks.

80. **Leveraging Data for Analytical Decision-Making:** The increasing availability of operational data within the power sector creates significant opportunities for advanced analytics, forecasting and optimisation of system operations. However, **the lack of structured access to high-quality datasets has limited the development of a robust analytics ecosystem and research within the sector.**

    The policy may therefore encourage the development of a **data analytics ecosystem**, enabling researchers, utilities and policymakers to utilise available datasets for system modelling, demand forecasting, operational optimisation and policy analysis. Such an ecosystem would support development of analytical tools tailored to the Indian system conditions and help improve evidence-based decision-making across the sector.

    Improved access to data would also enable independent research institutions and academic organisations to contribute to solving operational and planning challenges faced by utilities. Over time, such collaborative efforts could significantly enhance the analytical capabilities of the power sector and support the development of innovative solutions for managing complex electricity systems.

81. **Promoting Energy Efficiency and Waste-to-Energy Initiatives:** Energy efficiency and demand-side measures play an important role in improving overall system efficiency and reducing the need for additional generation capacity. However, many energy efficiency initiatives fall outside the direct operational domain of electricity utilities and therefore require coordination across multiple sectors and institutions.

    For instance, initiatives related to **waste-to-energy, urban waste management and energy recovery systems** often involve municipal authorities, environmental agencies and urban development institutions in addition to power sector entities. The policy may therefore encourage coordinated approaches involving relevant stakeholders to implement such initiatives effectively. Financing mechanisms, including innovative financial structures and green finance instruments, may also be considered to support these projects.

    While such initiatives can contribute to improved energy efficiency and resource utilisation, their successful implementation will depend on clear institutional responsibilities, coordination between sectoral agencies and availability of appropriate financial support mechanisms.

82. **Integrated Approach for Agricultural Energy Efficiency:** Energy efficiency in electricity utilisation, particularly in the agriculture sector, is a critical component of overall system efficiency. While existing programmes such as feeder solarisation and pump efficiency improvement address specific aspects, their implementation has remained fragmented and difficult to scale.

    A more integrated approach may be considered, wherein new agricultural electricity connections are provided through an **Energy Service Company** (ESCO)-based model, combining efficient pump sets with embedded solar PV systems (Agri-PV). Under such a framework, **the ESCO would be responsible for investment, operation and maintenance of both the pump and solar system, with performance linked to actual energy utilisation measured through AMI-enabled smart metering.**

    In addition, an alternative architecture based on a microgrid approach may be explored, wherein a centralised solar PV plant (of the order of 500 kW to 1 MW) serves a cluster of farmers. This may be configured either with decentralised pumps or with both generation and pumping infrastructure centralised. In such a model, the operating entity may supply **water-as-a-service,** rather than electricity supply. This approach may offer greater acceptance among farmers, as electricity is often perceived as an intermediate input, whereas water represents a tangible and directly valued output. Accordingly, monetisation through water supply may provide a more effective and scalable business model.

    The system may further incorporate GPS-based tagging and QR code-based identification

of PV systems and pumps to enable transparent monitoring of deployment, operation and maintenance.

83. **Mandating Efficiency in Public Procurement and Clarifying Policy Scope:** Energy efficiency improvements in appliances have been widely implemented through market mechanisms and voluntary adoption. However, large-scale impact may be achieved by leveraging government procurement as a policy tool.

    The policy may consider mandating that **all government procurement of electrical appliances meets minimum energy efficiency standards**, such as a specified star rating under the applicable labelling programme. Such a requirement would ensure that public sector demand drives market transformation, encouraging manufacturers to prioritise higher efficiency products.

    At the same time, care may be taken to ensure alignment of policy provisions with the appropriate legislative framework. **Certain elements such as carbon trading mechanisms originate from the Energy Conservation Act and may not fall directly within the scope of the Electricity Act under which the policy is framed.** Accordingly, while such mechanisms may be acknowledged, their inclusion within the policy may be clarified to ensure consistency with legislative mandates. **Clear delineation of institutional responsibilities across different legal frameworks would improve policy coherence and avoid potential overlaps or ambiguities in implementation.**

84. **Lifecycle Assessment and Competitive Framework for Waste-to-Energy:** The utilisation of municipal solid waste and agricultural residues for energy generation requires careful evaluation. Such initiatives should be undertaken based on **lifecycle techno-economic assessment**, rather than solely on indicative benefits, to ensure that they deliver genuine environmental and economic value.

    Further, projects involving waste-to-energy or biomass utilisation should be implemented through **competitive bidding mechanisms**, with clearly defined performance benchmarks. Regulatory frameworks may also ensure that tariff determination is linked to actual compliance with prescribed waste processing standards, such as pelletisation. In the absence of such monitoring, there is a risk that inferior practices such as open burning may persist while still receiving tariff support.

    From a financing perspective, **development of high-cost and emerging technologies such as that for WTE plants may require innovative approaches such as Contract-for-Difference (CFD) frameworks**, supported by appropriate budgetary provisions. Green financing may also be encouraged for distribution utilities, particularly for initiatives related to renewable integration, distributed energy resources and rooftop solar programmes.

Such targeted financial mechanisms would enable adoption of advanced technologies while ensuring cost-effectiveness and risk mitigation.

85. **Capacity-Based Storage Procurement and Amendment to Competitive Bidding Guidelines:** In the proposed Clause 6(6), *"Incentives, Procurement, and Regulation," it is stated that "To accelerate ESS deployment, Appropriate Commission should promote co-located battery storage with variable renewable energy projects. Grid operators may be assigned ESS for ancillary service management. Besides long-term PPAs, the Central Government will promote ESS development through market-based mechanisms including bilateral contract settlement. The Central Commission must establish required regulatory framework to implement bilateral contract settlement based capacity procurement."*

    It is proposed to additionally include the following text: "The Central Commission must establish required regulatory framework to implement bilateral contract settlement based **storage** capacity procurement. **The Central Government may amend the competitive bidding guidelines, to put this into effect**."

    The proposed insertion explicitly enabling bilateral contract settlement based storage capacity procurement and corresponding amendment of competitive bidding guidelines is a significant regulatory development. **Capacity-based procurement of Energy Storage Systems (ESS) represents a long-term financial commitment and must therefore be carefully aligned with identified system needs.** In absence of clearly defined accreditation norms, performance standards, and linkage with Resource Adequacy planning, such procurement may result in excess capacity creation and additional financial burden on consumers. Accordingly, it is suggested that while incorporating the proposed text, it may be clarified that **storage capacity procurement through bilateral contract settlement shall be undertaken based on approved Resource Adequacy Plans, with clearly defined availability obligations, performance parameters, and transparent competitive bidding processes to ensure cost-effectiveness and system reliability.**