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Embedding demand flexibility into India's electricity sector: A regulatory pathway to implementation

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Executive summary

India's peak power demand is set to rise sharply in the coming years, while rapid solar growth has widened the gap between midday supply and evening peaks. Meeting this demand by adding generation capacity is increasingly expensive, and storage may not be deployed fast enough to fill the gap. Demand flexibility – where consumers shift or reduce their use in response to grid conditions or prices – can defer costly investments, cut power purchase costs and lower customer bills. However, demand flexibility faces significant scalability barriers, including weak incentives for consumers, utilities, and aggregators; low consumer awareness; limited institutional capacity; and consumer privacy concerns.

Demand-side management in India has long meant energy efficiency. Similarly, demand response has mostly been characterised by emergency-driven load-shedding during critical peak periods. The policy discourse is now shifting towards continuous and multidirectional demand flexibility.

This paper suggests four sets of mutually reinforcing regulatory shifts that are needed to scale demand flexibility. Sequencing will vary based on state-specific context.

- ***Incentivise price-responsiveness and customer participation***. Pilot experiences suggest that consumer participation is low because customers lack meaningful financial incentives and awareness. An important aspect of the solution is designing tariffs that vary by time and location to reflect the true cost of supply. Early rollouts offer an opportunity to test price ratios and opt-in rates and assess their impact on system-friendly price-responsiveness. Tariffs should reach large commercial and industrial customers first. As markets deepen, hourly day-ahead pricing can be rolled out to large consumers. Regulators can also require distribution companies (discoms) to fund customer education and engagement programmes, prioritising large commercial and industrial customers.

- ***Set up utility-led programmes for success***. In the near term, discoms will remain the key implementers of demand flexibility, but misaligned financial incentives, limited data on customer flexibility, and limited utility capacity are key barriers. First, regulators can set targets grounded in load research and potential studies, tied to critical hours and performance requirements. Second, revenue decoupling – separating utility revenue from the amount of electricity it sells – would remove the discoms' disincentive from lower sales, and performance-based mechanisms such as shared savings would reward results. Third, regulators can allow structured cost recovery for pilots, designed with scalability as a key outcome and backed by rigorous evaluation, monitoring and verification (EM&V) that is made publicly available to all stakeholders. The responsibilities of demand-side management cells can evolve to cover the analytical capabilities required to design and evaluate effective programmes. Fourth, cost–benefit screening should be standardised with full consideration of the long-term benefits that demand flexibility can deliver beyond just power purchase costs. Finally, EM&V should measure dependable flexibility in critical hours rather than enrolled megawatts. It should also fix baseline methods at the outset; combine impact, process and market evaluations; use independent verifiers; and publish results.

- ***Enable third-party aggregators to extend the reach of demand flexibility.*** Aggregators bring capital, expertise and innovation that extend the reach of demand flexibility, but they lack legal recognition, viable business models and access to data. Regulators could enable aggregators by setting eligibility, registration and licensing rules. Near-term models include technology platforms for discoms, bill-saving services for large commercial and industrial customers, and utility-contracted aggregation. Interoperability standards, grid connection rules and visibility of local flexibility needs are also required. A data framework should limit access to sensitive customer data and require explicit consent and enforceable security standards.

- ***Establish demand flexibility as a grid resource.*** Demand flexibility has been excluded from broader planning processes. Regulators can require discoms to prioritise and assess non-wires alternatives before major transmission and distribution spending, using consistent evaluation criteria, standard cost–benefit methods and technology-neutral procurement. Flexibility should be treated similarly to supply-side resources in resource adequacy planning. Market rules should provide non-discriminatory access to energy, capacity and ancillary markets; discoms and State Load Despatch Centres need coordination protocols so they can procure flexibility where it is most needed.

The paper sets out a phased roadmap for moving demand flexibility from isolated pilots to a mainstream grid resource.

Immediate priorities: Build the evidence base and regulatory architecture. Regulators can achieve this by redesigning time-of-use tariffs to reflect marginal supply costs, commissioning discom-specific load research and potential studies, and strengthening institutional capacity. They could build an evidence base by establishing key frameworks – create licensing and data-access rules for aggregators, protect customer data, standardise cost–benefit and EM&V frameworks, and launch well-designed commercial and industrial pilots including EM&V and public reporting with clear plans for scalability.

Medium and longer-term priorities: Focus on activating programmes and achieving market integration for demand flexibility. Discoms can achieve this by broadening their reach through customer education campaigns; focusing on scaling successful pilots and programmes through diverse utility-led and aggregator-led models; piloting non-wires alternatives in constrained locations; and setting evidence-based targets and accountability mechanisms. Next steps would be to establish non-wires alternatives as a standard planning tool and enable demonstrated flexibility to count in resource adequacy based on dependable performance during critical hours. It is important that flexibility can compete on the same level as conventional resources in energy, capacity and ancillary markets; and that large consumers can benefit from more dynamic pricing.

This paper concludes that sustained, coordinated effort across stakeholders and a phased approach can establish demand flexibility as a reliable, cost-effective resource that supports renewable integration and improves affordability, reliability and resilience.

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Abbreviations

AERC	Assam Electricity Regulatory Commission
ARR	Aggregate Revenue Requirement
BEE	Bureau of Energy Efficiency
BRPL	BSES Rajdhani Power Limited
BYPL	BSES Yamuna Power Limited
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CFL	Compact Fluorescent Lamps
CPUC	California Public Utilities Commission
DAM	Day-Ahead Market
DER	Distributed Energy Resources
Discom	Distribution Company
DSM	Demand-Side Management
EM&V	Evaluation, Measurement and Verification
ERC	Electricity Regulatory Commission
FPPCA	Fuel and Power Purchase Cost Adjustment
GoI	Government of India
HVAC	Heating, Ventilation and Air Conditioning
IVA	Independent Verification Agencies
JVVNL	Jaipur Vidyut Vitran Nigam Limited
KERC	Karnataka Electricity Regulatory Commission
LEDs	Light Emitting Diode (bulbs)
M&V	Measurement and Verification
MERC	Maharashtra Electricity Regulatory Commission
MoP	Ministry of Power
NEP	National Electricity Policy
NWA	Non-Wires Alternative
O&M	Operation and Maintenance
PAT	Perform, Achieve and Trade
PBR	Performance-Based Regulation
PFC	Power Finance Corporation
RERC	Rajasthan Electricity Regulatory Commission
S&L	Standards and Labelling
SERC	State Electricity Regulatory Commission
SLDC	State Load Despatch Centre
TPDDL	Tata Power Delhi Distribution Limited
TP Mumbai	Tata Power Mumbai Distribution
UJALA	Unnati Jyoti by Affordable LEDs for All
UTs	Union Territories
VoLL	Value of Lost Load

Introduction

In the summer of 2026, India's electricity grid served a record peak demand of 271 GW (Grid India, 2026a), 41% higher than the 190 GW recorded in 2021 (CEA, 2021). National peak power demand is further projected to exceed 344 GW by 2030, a 24% increase, and reach 459 GW by 2036, a 69% increase (CEA, 2026a). At the same time, India has pursued ambitious renewable energy deployment in line with its climate and energy security commitments. The government has set a national target of installing 500 GW of non-fossil capacity by 2030, rising to 786 GW by 2036 (CEA, 2026a). Over the past decade, renewable electricity generation capacity has more than tripled, increasing from 87 GW to 296 GW, driven largely by the addition of variable resources such as solar (168 GW) and wind (58 GW) (CEA, 2026b).

The traditional approach of meeting peak electricity demand primarily by adding supply is becoming increasingly inefficient, especially as variable renewable resources make up a growing share of new capacity. Since 2019, solar has accounted for nearly two-thirds of India's added capacity (Spencer and Vautrin, 2026), intensifying the temporal mismatch between supply and demand: solar generation peaks around midday, while electricity demand typically peaks in the evening. As a result, ensuring adequate generation during peak demand periods is becoming a critical concern for electricity access, system reliability and energy security.

India is projected to be the largest driver of global energy demand growth through to 2035 (IEA, 2025), fuelled by rapid urbanisation, industrialisation, electrification and rising cooling demand. As populations, incomes and temperatures increase, maintaining grid stability and resilience will become increasingly challenging. In response, policymakers are placing greater emphasis on deploying large-scale storage and enhancing grid flexibility. Storage technologies are essential supply-side solutions for converting variable renewable energy into dispatchable power and enabling deeper integration of renewable sources. However, the required scale of storage could have significant cost implications, and deployment may struggle to keep pace with the growth in demand in the medium term.

Demand flexibility offers a complementary and cost-effective solution to address these challenges and create space for higher integration of renewables. Demand flexibility refers to the ability of consumers to adjust the timing, level or rate of their electricity consumption in response to grid conditions, price signals, periods of system scarcity, or periods of abundant renewable energy generation. Customers can make these changes either manually or automatically, acting themselves or through a third party. By shifting or reducing demand during times of system stress and increasing consumption when low-cost renewable energy is available, demand flexibility can help balance the grid, improve system efficiency, lower system costs, and deliver savings for both utilities and consumers.

Against this backdrop, this paper identifies key priorities for establishing demand flexibility as a mainstream resource in India's power sector and offers regulators and utilities a practical pathway to unlock its potential at scale. India has extensive experience in demand-side management and energy efficiency. In recent years, several states have piloted demand flexibility, and four have notified supporting regulations. The priority now is to translate these

insights into utility programmes and establish demand flexibility as a mainstream reliability resource. This paper identifies near-term actions and enabling provisions for a future in which demand flexibility can be valued, procured, traded and dispatched.

The paper is organised as follows. The second section outlines the core benefits of demand flexibility and barriers to implementation. The third section analyses demand-side management experiences and reviews India's regulatory trajectory. Building on this context, the fourth section identifies the policy enablers needed to design and scale these initiatives. The fifth section outlines options for programme delivery. The paper concludes with an actionable roadmap of next steps to enable demand flexibility as a reliable resource.

Benefits of demand flexibility and barriers to scaling

Integrating a high share of renewable energy will require thorough planning to address variability in electricity generation and the corresponding need for grid flexibility. Electrification, industrial growth and cooling loads are driving peak demand, and much of it falls outside solar generation hours. To further compound the challenge, traditional thermal resources built to meet peak demand are expensive and remain underutilised for most hours of the year. This creates a multi-year carbon and capital lock-in that inflates distribution companies' (discoms') power purchase costs and undermines efforts to decarbonise the power sector. Peak-load growth also drives the need for transmission and distribution investments, challenging the financially insolvent discoms.

Demand flexibility can be a robust tool for addressing some of these challenges and advancing critical public policy objectives. It can help reduce investments in expensive capacity additions, increase the integration and utilisation of lower-cost renewables, and reduce power purchase costs. It can also strengthen discoms' financial sustainability and make energy more affordable by lowering customer bills, particularly for low-income households (Sasidharan et al., 2021). It can lower exposure to price volatility and supply shocks, strengthening energy security. Flexible demand can reduce grid stress by relieving local congestion and improving grid resilience. It can also support decarbonisation by reducing marginal generation from carbon-intensive resources and supporting the growth of renewables.

The benefits demand flexibility creates depend on the nature of the flexibility, such as load shifting vs. load reduction, and the delivery mechanism, whether voluntary, automated or dispatchable. Load reduction removes demand from the system during peak hours, reducing total consumption. Load shifting moves consumption to a different time period, delivering system value only when electricity use shifts away from the critical hours that drive system costs.

Demand flexibility can be delivered through multiple mechanisms. First, voluntary price-responsive flexibility occurs when consumers shift or reduce their consumption in response to price signals or behavioural incentives. The magnitude of response may be uncertain and

depends on multiple factors, including the participants' priorities. Second, automated flexibility uses technologies – such as smart devices, energy management systems in buildings and direct load control – that respond to dispatch signals without the need for real-time consumer action. This delivers a faster, more reliable response than manual interventions. Finally, contracted dispatchable flexibility, mostly delivered by third-party demand aggregators and large consumers, provides a defined, measurable flexibility capacity backed by performance obligations and financial penalties for non-delivery. This distinction matters particularly for resource adequacy and grid services, where contracted capacity is more reliable than voluntary flexibility commitments that may not materialise.

Reliable demand flexibility programmes could deliver significant avoided-cost benefits for the discoms. Annex A provides a summary of such avoided costs and the underlying methodologies for estimating them.

Despite the clear value it offers to the power system, as demonstrated through several pilots, scaling up demand flexibility in India faces interconnected barriers. The key issues are discussed below:

- **Low incentives, lack of awareness, and uncertainty about consumer participation.** Consumer participation in demand flexibility programmes remains limited for two reasons. First, financial incentives are weak or absent. Even where time-of-day tariffs exist, their impact on consumers' price-responsiveness has not been evaluated or well documented. Second, consumers lack awareness about programme benefits, which directly dampens participation (MP Ensystems, 2025). Limited evidence on consumer behaviour prevents reliable estimates of participation and flexibility potential, constraining effective programme and incentive design (MP Ensystems, 2025).

- **Lack of clear financial motivation for utilities.** Discom revenue models rely on electricity sales – a higher volume generates higher revenue. Demand-flexibility programmes reduce consumption or shift it to cheaper hours, working directly against this core economic principle. Compounding this challenge, uncertainty about how system benefits and avoided costs are allocated and how they flow back to discoms undermines the case for adoption (AEEE, 2025).

- **Lack of viable pathways for aggregator involvement.** Third-party aggregators can extend the reach of demand flexibility programmes, manage complex implementation, and provide initial upfront capital. Without incentives to cover high upfront costs and scale operations, however, aggregators do not yet have a viable business model in India. Their participation is further hampered by technical barriers and information gaps: limited visibility into local flexibility needs, deficient or non-existent interoperability standards, and unclear rules governing market participation (AEEE, 2025).

- **Absence of a procurable demand flexibility product.** Regulators and discoms have not standardised the performance metrics required of a procurable flexibility product, such as megawatt response, availability, and ramp times. This prevents utilities from identifying end-use assets that can modulate load, whether through scheduled load shifting from municipal water pumping or through peak shaving via managed EV charging infrastructure. It also limits options for aggregators, who need a clearly defined product to pool and offer these resources.

- **Lack of coordination between different stakeholders:** Discoms lack system-level visibility into where flexibility is needed most, while State Load Despatch Centres cannot see customer-level assets on the distribution network. Similarly, aggregators have limited insight into where flexibility yields the highest benefits. Without established data-sharing protocols and coordination mechanisms among regulators, utilities, system operators, aggregators and consumers, the deployment of cost-effective demand flexibility will remain constrained.

- **Lack of institutional capacity:** Most discoms lack internal technical capacity – dedicated teams, software, and programme management expertise – to design, implement and evaluate demand flexibility initiatives. Although smart meter rollouts enable discoms to collect vast amounts of operational data, there is limited capacity to translate this data into actionable insights for targeting customers and assessing flexibility, which remains a major bottleneck (MP Ensystems, 2025; AEEE, 2025).

- **Long-term planning processes do not include demand flexibility:** Demand flexibility is routinely omitted from long-term planning, including for resource adequacy and transmission and distribution grid planning. Given that the deployment of dependable demand flexibility is rare and that decision-makers fail to recognise the long-term value of flexibility, its benefits remain undercounted or absent from system planning processes (AEEE, 2025).

- **Concerns over consumer privacy and data security:** Earlier pilots highlighted consumer and data privacy as major concerns; these continue to impact consumer trust and participation (AEEE, 2025).

Regulatory landscape for demand flexibility

For much of the past two decades, demand-side management (DSM) in India's electricity distribution sector has been synonymous with energy efficiency. Anchored in the Energy Conservation Act 2001 and operationalised through the Bureau of Energy Efficiency (BEE), early demand-side management practices centred on energy conservation and efficiency through initiatives like appliance standards and labelling, along with efficiency obligations for large industry under the Perform, Achieve and Trade (PAT) scheme.

These programmes demonstrated that durable demand-side management outcomes depend on aligning incentives across the value chain. Key outcomes included technical standardisation, target setting, and financial instruments such as tradable efficiency certificates issued against mandatory consumption reduction targets under the PAT scheme, as well as initiatives such as bulk procurement of LEDs to reduce costs under the UJALA scheme (Abagi, 2023).

The Forum of Regulators' Model Demand-Side Management Regulations, issued in May 2010, provided a common regulatory template for programmes at the state level. It required distribution licensees to set up demand-side management cells, conduct load research, and

report on programme evaluations. By 2024, more than 30 states and union territories had notified their own demand-side management regulations (Aggarwal et al., 2024). These interventions mainly promoted energy efficiency programmes because they were easy to implement and focused less on targeting critical peak periods. Historically, emergency-driven demand response in India has largely taken the form of traditional load shedding rather than structured demand-response programmes (Sasidharan et al., 2021). As the share of renewables is increasing in the generation mix, India's policy discourse is shifting from emergency-driven demand response to continuous, multi-directional demand flexibility.[1] It aims to treat consumer load as a continuously dispatchable asset that can be modulated through price signals, automation, behind-the-meter generation, storage assets, and aggregator-based participation – not only during emergencies but also in routine grid operations.

In recent years, a variety of amendments and regulations have laid the groundwork for demand flexibility. Maharashtra's Demand Flexibility Portfolio Obligation, notified in 2024, marked the first instance of this shift being formalised into a binding regulatory target (MERC, 2024). Assam followed with dedicated demand-response regulations in December 2024 (AERC, 2024), and Karnataka and Rajasthan have since notified their own regulations in 2026, signalling that this transition is now becoming a structural feature of Indian electricity regulation (KERC, 2026; RERC, 2026).

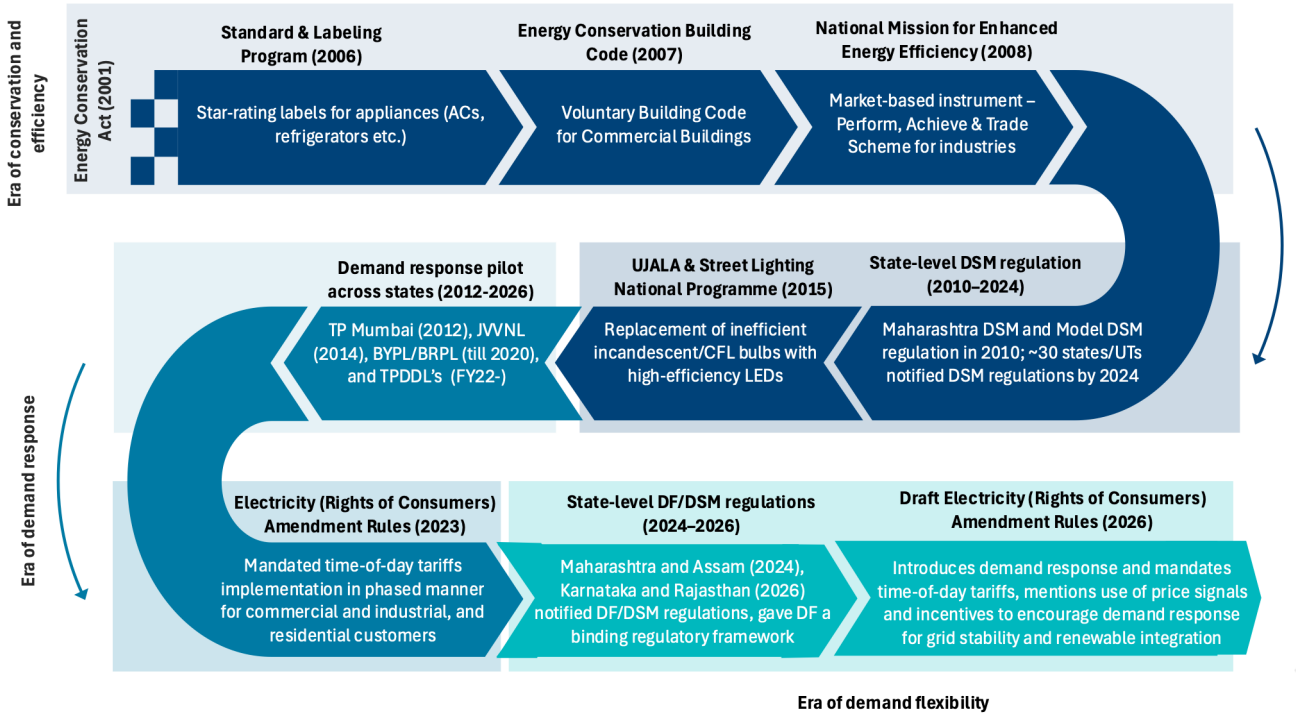
The Ministry of Power's draft Electricity (Rights of Consumers) Amendment Rules, 2026 also introduces demand flexibility into the regulatory framework (MoP, 2026a). Once notified, the Rules will empower State Commissions to develop a regulatory framework covering eligibility criteria for demand-response providers, consumer incentives, communication protocols, and measurement, verification, and settlement procedures. It will also mandate that commercial and industrial consumers with higher levels of demand shift to time-of-day tariffs[2] with other consumers (except agriculture) following soon after, creating direct price signals to encourage demand flexibility. These proposed changes reflect a broader policy shift toward strengthening grid stability and enabling greater renewable energy integration through active consumer-side participation (MoP, 2026a).

The slow uptake of state-level regulations underscores the need for the Forum of Regulators to issue a model demand flexibility and response regulatory framework that would support adoption by the remaining states, ensure consistency across states, and provide a coherent national framework. Figure 1 below shows the evolution of India's demand-management trajectory from a focus on conservation and efficiency to flexible demand response.

[1] In the energy sector, demand-side management (DSM) serves as the overarching umbrella, while demand response and demand flexibility are specific, time-sensitive subsets designed to adjust electricity consumption in alignment with grid needs. Although the terms 'demand response' and 'demand flexibility' are often used interchangeably, demand flexibility represents a more modern, automated, and dynamic evolution of traditional demand response, expanding beyond occasional peak shaving into continuous, bidirectional grid support.

[2] This paper uses time-of-day, the term used more frequently in the Indian context; it is used interchangeably with time-of-use, the more common international term.

Figure 1. Evolution of the demand-side management landscape in India



Demand flexibility regulations across states focus on different enablers. To compare these enablers, we evaluated each state's regulations against a common set of parameters spanning the full lifecycle of programme design and delivery. These include foundational elements such as consumer education and awareness; load research; evidence-based target setting and accountability mechanisms; and frameworks for cost–benefit analysis and evaluation, monitoring and verification (EM&V). In addition, key structural enablers include aggregator participation frameworks, technical standards, consumer data protection, the inclusion of demand flexibility in resource adequacy planning, and performance-based regulation. Together, these parameters capture not only whether states have addressed a given enabler, but also how comprehensively they have done so, ranging from detailed, actionable provisions to high-level references or no provisions at all. A comparison of the demand flexibility regulations of Assam, Karnataka, Maharashtra and Rajasthan is provided in Annex B.

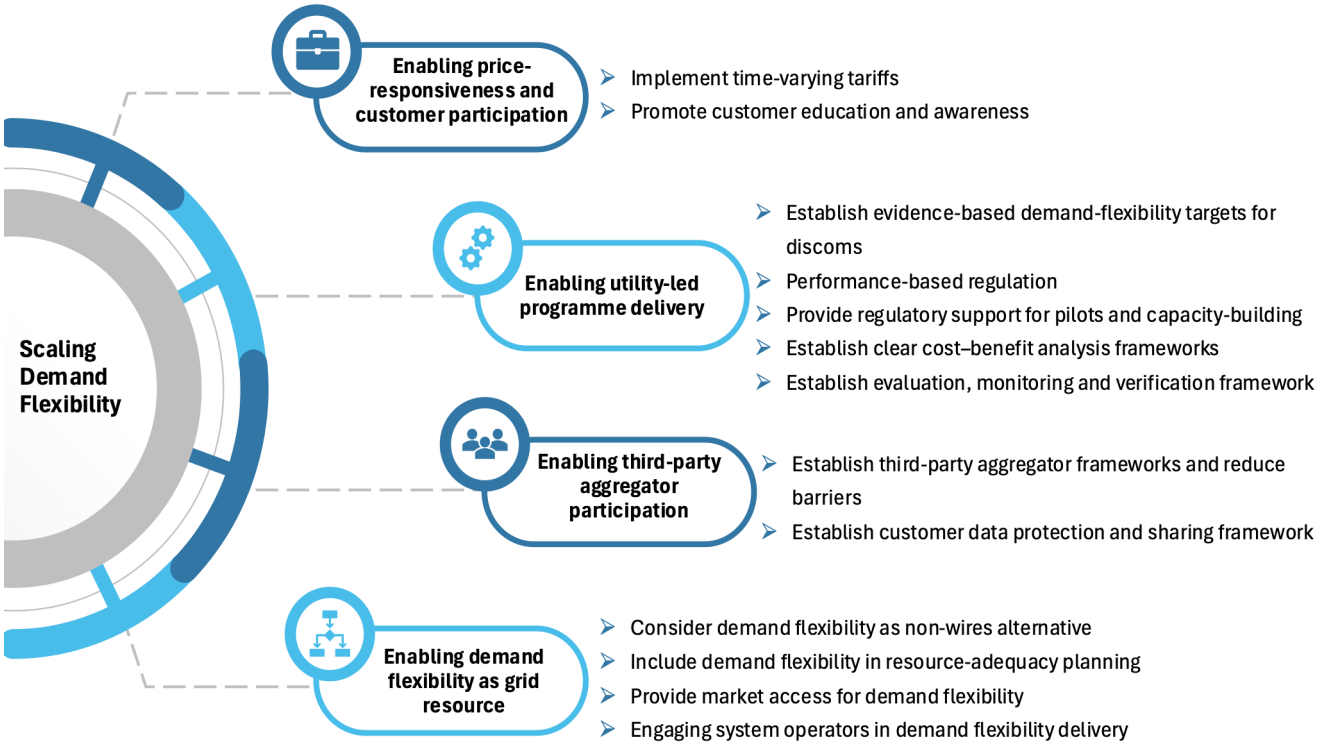
Establishing state-specific regulations that lay out robust frameworks and set clear targets is a foundational step for advancing demand flexibility. However, despite recent state-level progress, implementation of these measures has yet to extend beyond initial pilots. The critical next step is to translate regulatory mandates into programmes. The following section explores the key enablers required to unlock demand flexibility in India.

Enablers for demand flexibility

This section outlines the regulatory shifts that would enable wider-scale adoption of demand flexibility. The enablers are split into four categories based on key actors and level of maturity, as shown in Figure 2.

- **Customer engagement and price responsiveness:** motivating individual customers to change behaviour and adapting tariff design and incentives to reward the type of flexibility that benefits the broader system while also building customer awareness around demand flexibility. This is foundational to all programmes.
- **Utility-led programme delivery:** implementing regulatory changes needed to enable and motivate discoms, who are currently the dominant actors in designing, implementing and scaling programmes.
- **Third-party aggregator participation:** enabling third parties to pool resources and deliver flexibility for many consumers. Participation is currently limited, yet it is critical to reach more consumers and scale programmes cost-effectively.
- **Demand flexibility as a grid resource:** enacting regulations that place demand flexibility on a level playing field with traditional infrastructure investments and enable market participation.

Figure 2. Key policy enablers for demand flexibility



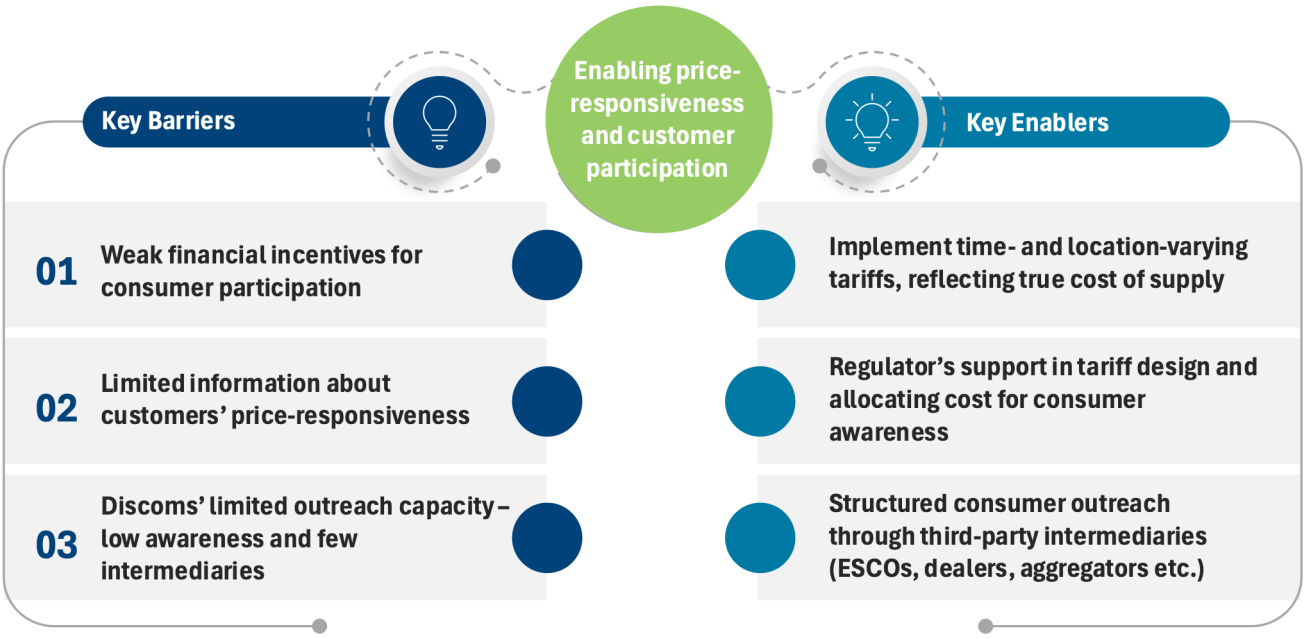
The sequencing of different enablers will vary depending on the specific jurisdictional priorities and existing infrastructure. However, a number of these enablers are mutually reinforcing. They must work in parallel and be coordinated through a coherent long-term vision. For example, efficient and cost-reflective time-varying tariffs should be designed and implemented as an immediate priority and refined over time based on customer price-responsiveness, since they will increase the value proposition of demand flexibility programmes for all stakeholders. Developing third-party aggregator frameworks is best done in parallel with the maturing of utility-led programmes and efforts to build customer engagement. Frameworks for deploying alternatives to traditional infrastructure investments (non-wires alternatives) can start with early-stage pilot programmes and then be refined through experience. Similarly, technology-neutral principles can be embedded early in market design to ensure non-discriminatory access to demand-side resources.

Enabling price-responsiveness and customer participation

Price-responsiveness and customer engagement are foundational to all demand flexibility programmes. Price signals create opportunities for customers and other stakeholders to capture value through price arbitrage – encouraging changes in behaviour, technologies and business models that can deliver demand flexibility where and when it is most needed. The success of these outcomes also depends heavily on customer engagement and confidence in the benefits these programmes can deliver.

Customer participation lacks certainty. Electricity customers do not have meaningful financial incentives to participate in demand flexibility. This is compounded by low consumer awareness of available response options and benefits that can be delivered. This section addresses the key regulatory enablers for engaging and motivating customers – the foundation on which utility-led programmes and third-party aggregator participation also depend.

Figure 3. Key barriers to and enablers of price-responsiveness and customer participation



Implement time-varying tariffs

- **Regulators can enable price-responsiveness and customer participation by designing and promoting time-varying tariffs that reflect the true cost of supplying power.**

Cost-reflective, efficient price signals, ideally differentiated by time and location, provide financial incentives for customers to align their consumption patterns with true supply costs and promote demand flexibility where and when it is most needed. Time-varying price signals can take different forms depending on how often prices change and how closely they reflect actual system conditions. Time-of-day or time-of-use tariffs can be defined at different granularities, from time blocks to hourly periods or by season. Critical peak pricing may apply higher rates during high-stress events, while the most sophisticated dynamic pricing may reflect day-ahead or real-time wholesale market prices.

Many Indian states have adopted time-of-day tariffs for select customer segments, particularly high-tension customers who draw electricity at higher voltages (Josey et al., 2024). However, this covers only a small category of consumers, and existing tariff structures are not necessarily aligned with costly critical peak hours. More importantly, it is not apparent that these tariffs have created significant behavioural change. This may be due to insufficient price differentials, inflexible demand, or a lack of customer awareness. Understanding these factors is important for informing future tariff design.

The draft National Electricity Policy (NEP) emphasises the importance of time-varying tariffs, advising state regulators to implement time-of-use tariffs starting with commercial and industrial consumers (MoP, 2026b). The draft Electricity (Rights of Consumers) Amendment Rules, 2026 goes further with a time-bound implementation plan to cover all

consumers (excluding agriculture) over two years. It also suggests a minimum threshold for tariff differences during peak periods and solar hours (MoP, 2026a).

Tariff design should reflect the time-varying costs incurred in procuring and distributing power. Tariffs are more effective when designed to reflect each discom's consumer base, consumption patterns and power procurement costs. However, while tariffs should reflect the costs of supply, they should not pass on costs arising from inefficiencies and imprudent power purchase decisions. As discussed in subsequent sections, tariffs designed only around cost recovery, without appropriate performance benchmarks, will result in inefficient behaviour.

Flexibility potential and the availability of advanced metering capabilities help determine which tariffs suit each customer segment. Large commercial and industrial consumers may offer higher flexibility potential and can provide more dependable blocks of flexibility with a smaller number of participants than residential segments. Residential consumers typically have inelastic demand during critical hours and thus require greater effort to engage. As a result, and as enabling infrastructure matures, best practice recommends extending time-varying tariffs and demand flexibility programmes to large commercial and industrial customers first, followed by smaller enterprises and residential consumers with flexible loads. Discoms can also introduce critical peak pricing to certain segments as a more granular and targeted incentive to reduce demand during critical hours.

As wholesale markets deepen, large consumers can be progressively placed on more granular hourly pricing, such as day-ahead signals. Where possible, locationally differentiated tariffs that reflect regionally varying supply costs can enable demand flexibility where it is needed most. Time-varying granular pricing may eventually be extended to smaller customers on an optional basis, allowing them to capture value through flexible technologies.

Combining these tariffs with enabling mechanisms that help consumers and their devices respond accurately to time-varying rates – such as in-unit displays, mobile notifications, access to usage patterns, and dashboards – delivers the greatest impact. On a structural level, it can be valuable to encourage the participation of third parties who could help consumers optimise behaviour in accordance with these time-varying tariffs. Regulators may need to balance two competing goals: updating tariffs regularly so they reflect changing supply costs and daily load shapes, and giving consumers enough certainty to change their behaviour and invest in new technologies.

Developing these tariffs will take time. Early rollouts of cost-reflective tariffs offer important learning opportunities to assess consumer responsiveness and affordability across segments and determine whether the tariffs are fit for purpose. Features include testing different price ratios and their impact on load shifting and load reduction, opt-in rates, and time granularities. As renewable energy penetration increases, tariffs may need recalibration to reflect the grid's new realities. Recognising this design option in regulation as a key enabler of demand flexibility and implementing it alongside broader demand flexibility measures is important.

Promote customer education and awareness

- **Regulators can boost the success of demand flexibility initiatives by requiring discoms to allocate resources towards customer education and awareness.**

  The success of demand flexibility outcomes depends on customer participation, which in turn depends on the rewards offered for changing their behaviour. To motivate them to act, discoms should clearly inform customers about individual benefits, such as bill savings, and the collective value of flexibility to the system, including cost savings and reduced emissions.

  Programme design should not expect to always engage all customers. Discoms can achieve greater system flexibility by prioritising direct engagement with large commercial and industrial customers with strong potential to adapt their electricity usage. In time, as demand flexibility grows, discoms can utilise existing touchpoints such as electricity bills, routine field operations and customer service centres to communicate programme value to a broader base. Third-party intermediaries such as equipment manufacturers, appliance dealers and energy service companies can help consumers assess potential benefits and payback. Engagement through these channels is particularly valuable when consumers are making energy investment decisions. Beyond more targeted, utility-led customer messaging, public awareness campaigns that promote demand flexibility and its societal benefits – not just individual savings – can broaden its reach and legitimacy. Moreover, publicising pilot results and customer success stories can help build credibility and encourage participation. Current state regulations recognise the importance of consumer engagement to a programme's success and allow cost recovery for such activities.

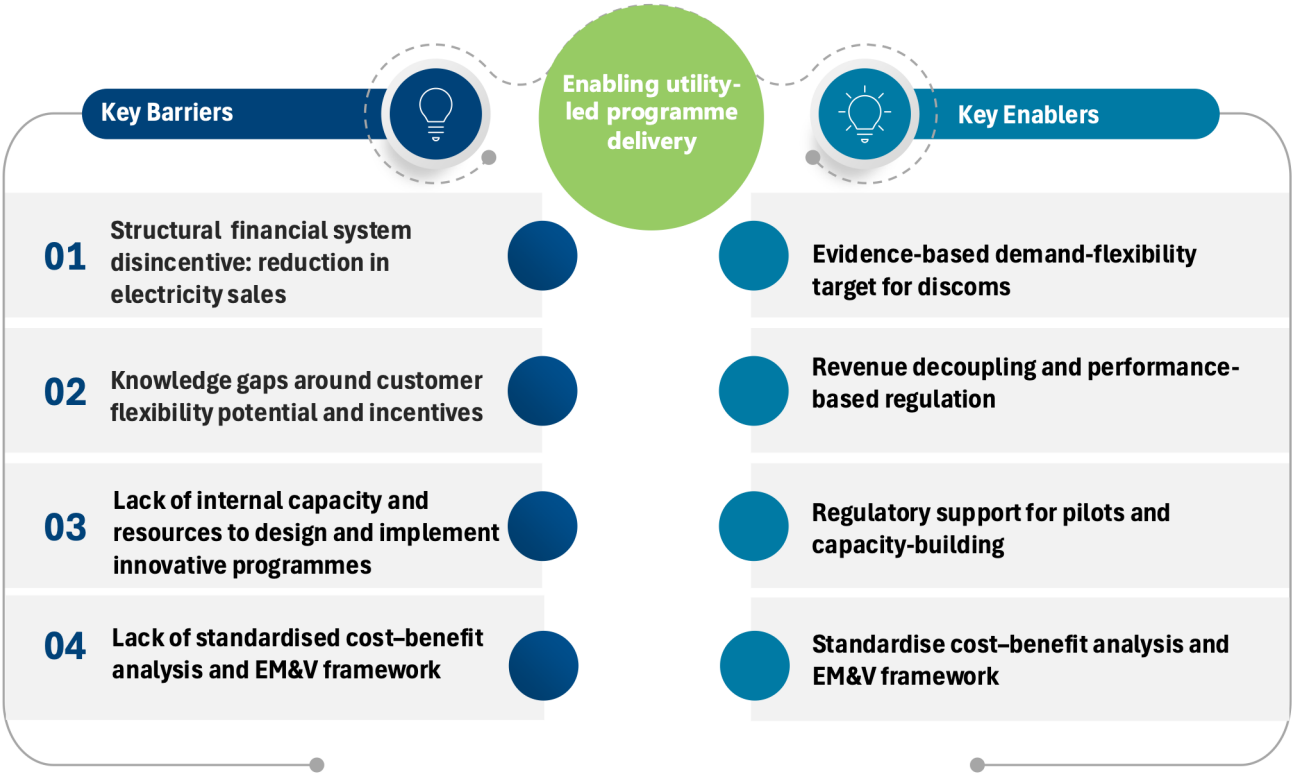
Enabling utility-led programme delivery

Discoms are central to India's electricity distribution system and serve as the primary implementers of demand flexibility under the current regulatory framework. However, financial, technical and regulatory constraints impede their ability to scale demand flexibility programmes.

First, a key barrier to discom-led demand flexibility is the perceived financial disincentive. Reduced electricity sales from demand flexibility programmes are perceived to run counter to discoms' financial interests. Second, regulators and utilities face knowledge gaps about customers' flexibility potential and motivators, creating uncertainty about programme outcomes for discoms. Third, most discoms lack the internal capacity and resources to design and implement innovative programmes and leverage the vast amounts of data generated by smart meters. Finally, these constraints are compounded by the absence of standardised frameworks for assessing programme cost-effectiveness and verifying the savings achieved from flexibility programmes. This stems in part from the fact that decision-makers are not familiar with or are uncertain about whether the projected benefits will be realised in practice. This reinforces the tendency to evaluate demand flexibility narrowly in terms of easily quantifiable short-term benefits while discounting long-term system value that is harder to see and attribute.

This section focuses on gaining experience, building the foundation, and realising these benefits through programmes more immediately, while the long-term planning processes continue to evolve. It discusses the key enablers for furthering utility-led solutions: performance-based incentives and revenue decoupling to align discom incentives with the value of demand flexibility; evidence-based targets grounded in state-specific data; regulatory support for pilots and institutional capacity-building; standardised cost–benefit analysis frameworks for screening the cost-effectiveness of programmes; and robust EM&V to ensure programme integrity.

Figure 4. Key barriers to and enablers of utility-led programme delivery



Establish evidence-based demand flexibility targets for discoms

- **Regulators can advance demand flexibility by setting evidence-based, discom-specific targets reflecting their customer base.**

  Selecting the right metrics and setting targets helps shift from voluntary discom approaches to a more coordinated, systemic effort to embed demand flexibility in utility planning. Effective targets are based on key metrics tied to long-term priorities. It is particularly useful to align these targets with the most critical hours that drive investment needs. For example, metrics could include reducing peak load, reducing expensive short-term power procurement, reducing ramping needs, improving system load factors, deferring or avoiding capital expenditures, and reducing involuntary load-shedding events.

Targets should be realistic, achievable and based on detailed statewide, discom-specific load research and studies that evaluate the technical, economic and achievable potential of different customer segments. Regulators can look to other regions for existing methodologies to assess flexibility potential and adapt them to the Indian context.[3]

Regulators can start with standardising data requirements, models and tools that allow discoms to assess potential in a consistent and transparent way. Where available, smart meter data can inform potential and targets. Until detailed studies are available, pilot programmes can also offer a good basis for setting demand flexibility targets. They provide empirical data on what can be achieved and potential participation rates for different customer segments, helping bridge the gap between theoretical targets and achievable potential. Demand flexibility targets can be made actionable by defining a standard procurable product – specifying parameters such as megawatt availability, response time, duration, availability window and frequency of activation to link regulatory obligations to performance specifications. Holding discoms accountable for meeting targets is crucial for the success of utility-led programmes. In the early stages of implementation, incentives are ideally prioritised over penalties. Penalties are more appropriate once discoms have run pilots and built the technical capacity to design and implement cost-effective programmes. Incentives and penalties are best informed by the avoided costs that demand flexibility delivers.

Of the four states that have issued demand flexibility and demand response regulations, all except Assam have set targets based on peak demand (MERC, 2024; RERC, 2026; KERC, 2026). However, while state regulations have directed discoms to conduct potential studies and load research, the current targets do not reference any formal potential studies or load research, which raises concerns about their achievability. By contrast, Assam's regulation directs discoms to conduct potential studies before setting targets (AERC, 2024). In Rajasthan, the first year after notification was treated as a preparatory year without penalties to help discoms gain experience (RERC, 2024).

Enforce performance-based regulation

- **Performance-based regulation can align the interests of the discom with the system value of demand flexibility.**

A key step in unlocking the potential of demand flexibility through utility-led programmes is to shift from the current cost-plus ratemaking approach to performance-based regulation (PBR). PBR provides discoms with tangible incentives to implement demand flexibility programmes by shifting their financial incentives away from selling more electricity to improved grid performance, efficiency and customer-side resource optimisation, thus achieving system cost savings (Nethercutt, 2023). Further, revenue decoupling – delinking the volume of electricity sales from utility revenue, which is a core mechanism of PBR – would address the perceived financial risks of demand flexibility for discoms. These benefits will flow through to customers over time.

[3] As an example, see *California Demand Response Potential Study, Phase 3*, May 2020 (Gerke et al., 2020).

Under a multi-year tariff process, allowable revenue is forecast based on projected sales volumes. Revenue decoupling ensures that reductions in sales attributable to demand flexibility are recovered through programme benefits and controlled tariff adjustments in the subsequent tariff periods. This removes any financial disincentive to implement demand flexibility programmes. Although India's multi-year tariff framework already provides reconciliation through true-up and fuel and power purchase cost adjustment (FPPCA) mechanisms, these alone do not give discoms certainty that they can recover any revenue reductions caused by demand-side measures.

PBR mechanisms also reward discoms with financial incentives, such as shared savings mechanisms, for exceeding demand flexibility targets like peak-load reduction, system utilisation, customer participation rates or energy savings, and they levy penalties for underperformance. PBR does not prescribe mechanisms required for meeting the targets: discoms can choose which methods to employ. In the long term, these metrics can be embedded in multi-year tariff processes to drive continuous improvement by linking programme performance to revenue recovery. Beyond performance-based mechanisms, government-owned discoms may also be incentivised through non-financial recognition of high performance, such as public commendations and ranking, or performance-based awards. Currently, no states have addressed PBR or revenue decoupling associated with demand flexibility within the regulations.

Provide regulatory support for pilots and capacity-building

- **Regulators can enable the adoption of demand flexibility through support for pilot programmes and utility capacity-building.**

  India has conducted several demand flexibility pilots, and a few are currently underway. But scalability remains limited, and these pilots are concentrated in a few progressive utilities (Sasidharan et al., 2021). Pilot trials are important for demonstrating the practicality of demand flexibility programmes and testing real-world feasibility and costs before full-scale implementation. Pilots also help discoms to prepare for and build their capacity to manage full-scale programmes. By allowing structured cost recovery for demand flexibility pilots, regulators can enable discoms to test innovative solutions and technologies without exposing them to undue financial burden. This would provide greater certainty and support the expansion of flexibility potential.

  In the states running these experimental programmes, discoms will need support to transition from the pilot phase and establish structured demand flexibility programmes. Regulators can facilitate this transition by requiring pilot designs to include clear objectives, expansion pathways and robust EM&V methods that capture key lessons and inform future scale-up.

Standardised frameworks for programme design and EM&V would also improve the consistency and comparability of results across discoms, accelerating knowledge-sharing and replication.[4] Pilot findings should be clear, actionable and publicly accessible to all stakeholders, including the Forum of Regulators, to raise awareness and inform regulatory action in other states.

These experiments will also require regulators and discoms to allocate resources to build institutional capacity. This includes ensuring discoms have the technical assistance they need, particularly international experience and lessons learned from jurisdictions where similar programmes have been successfully implemented. These needs include forecasting and analytics capabilities to translate granular smart meter data into time- and location-specific flexibility potential and design appropriate incentives; systems and processes to dispatch price or direct-control signals to consumers; and real-time verification of consumers' responses to these signals. Standardising data requirements, tools and methodologies can also reduce the burden on discoms to develop their own analytical approaches from scratch.

Some state regulations require discoms to set up dedicated demand flexibility/demand-side-management cells (for example, in Rajasthan and Karnataka), and some also establish a commission-level demand flexibility/demand-side-management consultation committee to review discom programmes and progress reports (as in Maharashtra). Discom cells can play a critical role in building capacity. However, a multi-state assessment highlights that many discom DSM cells currently remain inactive, under-resourced, or staffed on an ad hoc basis, often lacking the technical capacity to lead load research, programme design, and cost-effectiveness evaluations. Moreover, progress on DSM has been uneven across states. For example, in Delhi, discoms have run rebate-based AC replacement programmes through DSM cells. In contrast, DSM budgets allocated in Karnataka and Gujarat went unused, pointing to a lack of funding-ready projects (Aggarwal et al., 2024). To move beyond compliance reporting, DSM cells need dedicated staff with expertise in demand flexibility; resources and tools for designing and evaluating programmes; and capabilities for procuring resources and managing third-party relationships, including with aggregators.

Establish standardised cost–benefit analysis frameworks

- **Regulators can better value and capture long-term benefits of demand flexibility by standardising cost–benefit analysis frameworks for cost-effectiveness screening.**

Demand flexibility generates a variety of system benefits that materialise over the long term. A systematic evaluation framework can help identify the most cost-effective programmes, guide efficient allocation of discom resources, and maximise long-term benefits. This process can involve regulators mandating cost-effectiveness screening and standardising the methodologies and reporting templates for assessing benefits and costs.

[4] For example, the Ontario Energy Board in Canada created a pilot design manual and required discoms to incorporate this into funding applications for pilots (Faruqui et al., 2016).

Consideration of benefits must be holistic and include long-term avoided costs beyond power procurement costs, including avoided generation capacity, distribution and transmission infrastructure costs. Annex A lists potential benefits to be considered. Where possible, benefits should be monetised within the evaluation framework. Regulators and utilities may also choose to recognise hard-to-quantify or non-monetisable benefits, such as resilience or energy security, to reflect broader societal objectives in the analysis.[5] In practice, multiple cost-effectiveness tests are applied together, each offering a different perspective about the same programme. Most importantly, cost-effectiveness frameworks are tools that inform programme design and incentives – not rigid gatekeeping mechanisms that become barriers to implementation. The Total Resource Cost test establishes whether the programme creates net system value for society and is often used as the primary screening test. The Utility Cost Test identifies whether the utilities programme costs justify the benefits and may inform whether better cost recovery mechanisms are needed for otherwise beneficial programmes. The Ratepayer Impact Measure checks equity impacts on non-participants. The Societal Cost Test captures broader non-monetised benefits such as emissions and resilience. The right combination can be customised to reflect specific state policy goals – tests that are too narrow risk screening out programmes that deliver significant value, while those that are overly broad may validate programmes that are not genuinely cost-effective. In the early stages of market development, when empirical data on programme benefits is limited, regulators can allow well-designed programmes to proceed even where the analysis is indicative rather than definitive and use EM&V results to refine cost–benefit assessments and programme design over time.[6]

Current state regulations have mandated cost-effectiveness screening. They are likely to suffer from inconsistent application, however, due to the absence of standardised reporting requirements, narrow consideration of longer-term benefits, and limited guidance on how to quantify the benefits. For example, Rajasthan recognises a broader range of benefits, including avoided power procurement and avoided capacity under the regulatory approval tests for demand flexibility (RERC, 2026); several states account only for avoided power procurement costs. Most states also consider Ratepayer Impact Measure Test for programmes. Although it is important to consider the impact of demand flexibility programmes on rates, applying stringent rules to ratepayer impact measure thresholds without fully considering long-term benefits or placing a narrow focus on tariffs alone will exclude programmes that would otherwise improve system reliability, reduce customers' overall bills, and improve energy affordability.

[5] For reference, several studies from other jurisdictions describe the benefits of demand flexibility measures and the methods used to quantify them, particularly avoided costs. California's Avoided Cost Calculator sets out methodologies for estimating avoided-cost components associated with distributed energy resources (CPUC, 2024). Avoided Energy Supply Costs in New England provides methodologies and estimates for avoided energy-supply costs, which several jurisdictions use in cost-effectiveness assessments of energy-efficiency programmes (Synapse Energy, 2024). The New Hampshire Value of Distributed Energy Resources study presents methodologies and values for behind-the-meter resources (New Hampshire Department of Energy, 2021).

[6] For reference, a well-developed guide for conducting cost–benefit analysis is the *National standard practice manual for benefit-cost analysis of distributed energy resources* (Woolf et al., 2020).

Establish an evaluation, monitoring and verification framework

- **A regulatory mandate requiring robust and consistent evaluation, monitoring and verification can help ensure programmes are fit for purpose.**

  Evaluation, monitoring and verification (EM&V) are essential for assessing the real-world impact of demand flexibility measures. Weaknesses in EM&V methods can undermine a programme's credibility. Focusing on four critical elements can improve the accuracy and reliability of assessments.

  First, effective EM&V measures dependable flexibility delivered during the system's critical hours, rather than relying solely on enrolled or theoretical megawatts. A well-defined baseline provides the counterfactual against which programme impacts can be assessed. Because the choice of counterfactual is consequential and forms the foundation of programme evaluation, regulators should require utilities to specify their methodology at the programme approval stage rather than after implementation (Webster et al., 2015).

  Second, evaluation frameworks too often rely only on post-hoc estimates of energy savings. Drawing on MERC's demand flexibility regulation, regulators can require three complementary forms of assessment: impact evaluations that measure direct energy and demand savings and co-benefits; process evaluations that identify operational bottlenecks and delivery inefficiencies, and market-effect evaluations that track structural transformation, including permanent shifts in product availability and efficiency baselines (MERC, 2024).

  Third, conflicts of interest between programme implementers and evaluators can compromise the credibility of results. Independent verification by qualified third parties, strictly separated from programme design and equipment supply, is therefore essential.

  Finally, manual and opaque reporting increases the risk of error and weakens oversight. Regulators can promote automated analysis; require public disclosure of load research, EM&V reports and compliance metrics; and establish standardised frameworks that ensure consistency across programmes. Together, these measures strengthen transparency, accountability and replicability.

  Current pilots lack standard EM&V processes: detailed monitoring reports have often not been produced, and baselines and evaluation results are rarely made public. In recent years, states with demand flexibility regulations have set out EM&V processes and defined the qualifications of Independent Verification Agencies (IVAs), but the provisions are yet to be put into practice. Implementing these frameworks will be crucial as programmes scale.

Enabling third-party aggregator participation

Third-party demand flexibility aggregators are private entities that can play a pivotal role in scaling. By bringing specialised expertise, capital and technological innovation, they can complement utility-led programmes. In an enabling regulatory environment, their commercial

motivation can drive more efficient programme design and delivery, while streamlining participant onboarding, particularly among hard-to-reach customer segments.

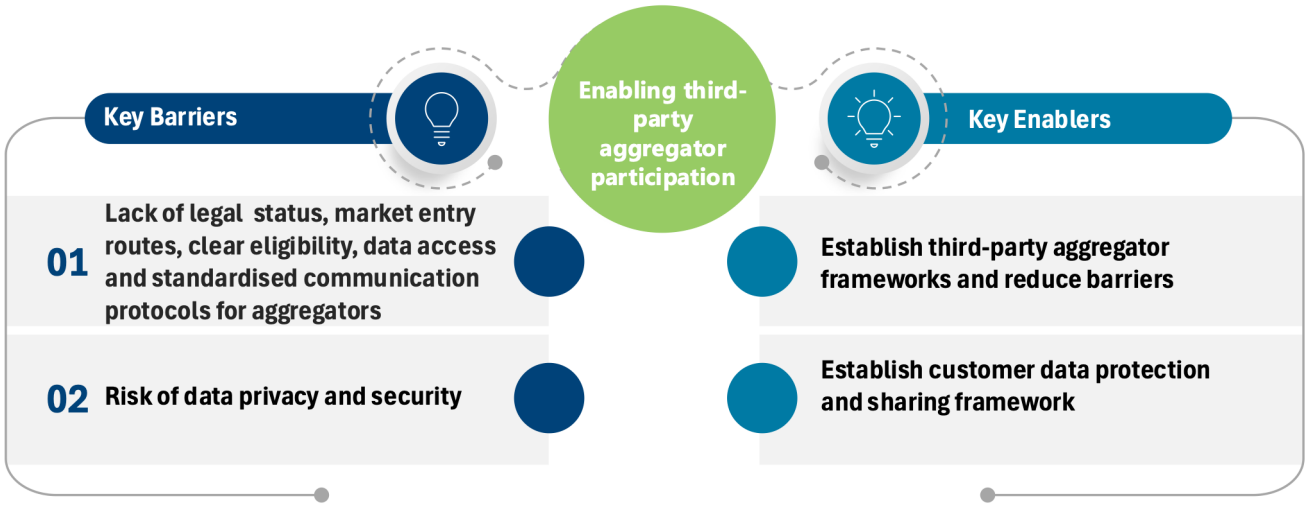
As discussed earlier, however, significant practical barriers remain. First, aggregators lack formal regulatory recognition. Without legal status, defined market-entry routes, and clear eligibility criteria, they cannot operate with the certainty needed to justify investment.

Second, without customer motivation and aggregators' access to the wholesale market, viable near-term business models do not exist. Discoms are neither required to engage aggregators nor necessarily motivated to do so, given the perceived risks of revenue loss and the possibility of collusion between third parties and customers.

Third, information barriers limit aggregators' ability to identify and target flexibility potential. They lack adequate access to consumer usage data, hosting capacity information, and standardised communication protocols. As a result, they struggle to locate flexible resources, interface with utility infrastructure, and build consumer trust.

This section discusses essential enablers and motivations for third-party aggregator participation: establishing clear frameworks for aggregator registration, licensing and market participation; reducing technical and information barriers through standardised data-sharing and interoperability protocols; and establishing a customer data protection framework that safeguards consumer trust while enabling access to essential data.

Figure 5. Key barriers to and enablers of third-party aggregator participation



Establishing third-party aggregator frameworks and reducing barriers

- **Regulators can foster third-party demand flexibility aggregation by establishing clear rules and reducing barriers to participation.**

  Robust demand flexibility frameworks provide the revenue certainty needed to justify the high capital investments in aggregation platforms, technology infrastructure and operational capabilities needed. In their absence, demand flexibility may be inaccessible to smaller consumers who could collectively offer significant potential, and larger consumers may miss out on specialised services that aggregators are best placed to provide.

  Given limited third-party aggregator participation in demand flexibility programmes, formally recognising and acknowledging their role is an immediate priority. This may include developing well-defined eligibility criteria, registration and licensing frameworks, including streamlined processes for aggregator approval,[7] and clear rules for participation, which may include standardised contracting templates and performance-accountability mechanisms.

  Regulators can facilitate their involvement by establishing market routes and access for aggregators to design and implement programmes. In the near term, aggregators can operate through several models: as technology platforms or service providers to discoms, as service providers delivering bill savings to large commercial and industrial consumers, or through bilateral utility-contracted aggregation. These are opportunities to generate a viable business case and build aggregator capability, portfolios and operational experience while the broader regulatory and market framework develops.

  Scaling up will also require addressing technical barriers: grid data transparency so aggregators know where and when demand flexibility is most valuable; mandated interoperability protocols to interface with discom and customer equipment; and clear connection standards so flexible resources, especially storage, can connect safely and predictably.

  State regulations recognise third-party aggregators, but few have operational frameworks. For example, Rajasthan has directed utilities to establish a registration and governance framework and maintain a digital registry (RERC, 2026), and Assam requires adherence to Bureau of Indian Standards equipment standards for interoperability (AERC, 2024).

Establish customer data protection and sharing framework

- **By establishing a clear framework governing aggregator access to customer data, regulators can help advance demand flexibility programmes and ensure customer data protection.**

  There is a key information asymmetry between utilities and third parties in their respective access to customer usage data. Successfully designing and implementing demand

[7] For reference aggregator frameworks, see NESO, 2023, and NY PSC, 2017.

flexibility programmes require granular data on customer usage patterns to identify flexibility potential and engage customers easily. However, robust customer data protection standards are necessary prior to allowing third-party access. The absence of strong data protection frameworks can leave customers vulnerable to data misuse and security issues; this will undermine trust and eventually weaken the social benefits of demand flexibility programmes.

As a best practice, regulators can establish clear frameworks that allow aggregators to access only essential, non-personal customer data and mandate explicit customer consent. It is vital to clearly communicate to customers who can access their energy data and how it may be accessed, used, stored and shared. Existing national data protection rules will dictate some of the requirements for these data-sharing frameworks. Regulators can also protect consumers by developing technical standards for data storage and security, and by establishing enforcement processes and accountability mechanisms for noncompliance.

Only a few state regulations, such as those of the Assam and Rajasthan Energy Regulatory Commissions, have explicitly established guidelines for consumer data protection; the Rajasthan Energy Regulatory Commission, in particular, refers to the Digital Personal Data Protection Act, 2023 (RERC, 2026; MoLJ, 2023).

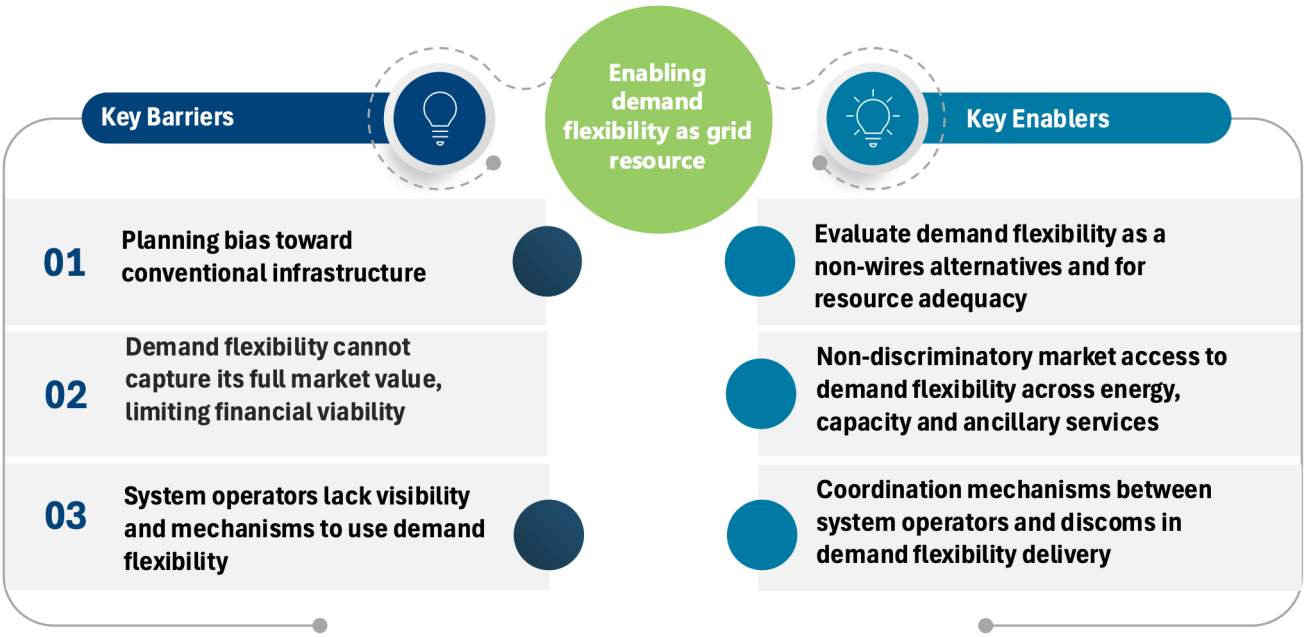
Enabling demand flexibility as a grid resource

For demand flexibility to reach its full potential and reduce system costs, it must be placed on an equal footing with other capital investments and embedded as an alternative in long-term planning. This goal is currently constrained by structural and market barriers. As discussed earlier, one of the main barriers is the prevailing cost-of-service regulation that favours capital-intensive investments. Long-term planning processes reinforce this bias, with demand flexibility largely absent in practice. Demand flexibility does not have access to energy, capacity or ancillary service markets, which limits its ability to compete with conventional resources on comparable terms. Further, the lack of established protocols and coordination mechanisms between discoms and system operators limits coordinated dispatch when demand flexibility is most needed.

This section discusses the key enablers for treating demand flexibility as a broader grid resource: requiring its consideration as a non-wires alternative (NWA) to traditional transmission and distribution investments; mandating its formal inclusion in resource adequacy; ensuring non-discriminatory market access; and engaging system operators in demand flexibility delivery.

In addition to the recommendations provided below, recognition and valuation of demand flexibility will require a national enabling framework. The text box on page 30 outlines how this enabling framework can coexist with state-level institutions.

Figure 6. Key barriers to and enablers of demand flexibility as a grid resource



Consider demand flexibility as a non-wires alternative

- **Regulators can lower costs and unlock the full value of demand flexibility by treating it as an alternative to traditional transmission and distribution solutions.**

Demand flexibility can defer costly transmission and distribution infrastructure by providing cost-effective load relief on the networks. However, India's current cost-of-service regulation creates a bias toward capital-intensive solutions in transmission and distribution infrastructure planning.

To level the playing field for demand flexibility, regulators can require discoms to evaluate NWAs prior to undertaking capital-intensive investments in transmission and distribution.[8] NWAs can meet the same system reliability requirements using a portfolio of decentralised resources in a more cost-effective and emission-friendly manner.

Although NWAs may not meet every identified system need, they have proven valuable in certain situations. Regulators can lay the groundwork by defining clear, transparent processes to identify, evaluate and procure NWAs. As a first step, regulators may define screening criteria – such as cost, lead time and the type of service needed – that set the minimum conditions for triggering an NWA evaluation before approving any transmission and distribution investments. These screening criteria may be customised by utilities to meet the local needs of the system.

[8] For example, see the Joint Utilities of New York's NWA opportunities: https://jointutilitiesofny.org/nwa-opportunities

Regulators can also establish standardised frameworks for conducting cost–benefit analyses to evaluate potential NWA opportunities against traditional solutions. Regulators can help develop clear, competitive procurement processes that outline NWA performance requirements while ensuring neutrality in the technologies and business models used to deliver solutions.[9] To ensure that solutions address system needs, regulators can also require discoms to continually monitor and publicly report on NWAs' performance.[10]

NWA implementation can start with pilots that test evaluation, procurement and implementation. As experience deepens, lessons from these pilots can help shape frameworks and processes for future NWA implementation at scale. Currently, there are no state regulations that instruct discoms to consider NWAs as alternatives to infrastructure investments.

Include demand flexibility in resource adequacy planning

- **Regulators can mandate that discoms embed demand flexibility in resource adequacy planning and provide clear guidance on how to value its contribution.**

Embedding demand flexibility in resource adequacy frameworks is fundamental for ensuring it is treated the same as supply-side options. The *Guidelines for Resource Adequacy Framework for India* recognise demand response as an integral part of the resource adequacy process (MoP, 2023). While state regulations also require inclusion of demand flexibility in resource adequacy planning, it is mostly absent in practice. This is largely because dependable demand flexibility programmes do not exist.

Resource adequacy requires more than including only enrolled flexibility; it requires methodologies to translate it into dependable capacity that reflects demonstrated performance during critical hours. Excluding these solutions from key planning processes will lead to under-deploying cost-effective solutions and overbuilding generation capacity, particularly expensive peaker units that generate for only a few hours per year.

Regulators can enable integration of demand flexibility in resource adequacy planning by requiring discoms to quantify and account for the long-term contribution of aggregate flexibility resources to meeting future load growth. In practice, this can take the form of treating demand flexibility as a load modifier (i.e., evaluating net load after accounting for future load reduction and shifting), or it can be treated as a supply-side resource and assigned a capacity credit reflecting how reliably it shows up when needed.

[9] As an example, see Request for Proposal issued by Con Edison, 2025.

[10] For illustration of quarterly reporting of a customer-sided solution, see Brooklyn Queens Demand Management Q1 2026. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={405F849E-0000-C449-97A0-2EC5B2475A0F}&DocTitle=Con%20Edison%20BQDM%20Q1%202026%20Quarterly%20Report

Provide market access for demand flexibility

- **Regulators can provide non-discriminatory access to wholesale markets for demand flexibility.**

  As wholesale markets mature and third-party aggregators gain experience, market participation will be crucial to delivering demand flexibility in real time. Non-discriminatory market access can unlock a range of programmes and savings. As discussed earlier in this paper, it is important for utility evaluation and screening of demand flexibility resources to consider multiple value streams, including energy, capacity and ancillary services. An initial step is to ensure that demand flexibility resources can participate in existing energy markets through power exchanges. As capacity and ancillary markets evolve, regulators can ensure market access rules and settlement frameworks are technology-neutral, so demand flexibility can participate and deliver where and when it adds the most value across multiple services.

Engaging system operators in demand flexibility delivery

- **Regulators can enhance the delivery of demand flexibility by mandating coordination between system operators and stakeholders, particularly discoms.**

  Discoms are responsible for delivering demand flexibility in the distribution system and are the key interface with consumers. State Load Despatch Centres (SLDCs), on the other hand, are responsible for balancing the grid and dispatching resources. Coordination between the two enables demand flexibility to be targeted where it is needed most and will deliver the highest system value. This gives SLDCs an effective option to procure demand flexibility products directly, ideally through competitive procurement, to meet their system needs. As demand flexibility scales, it can be mobilised as a real-time, system-level resource, provided coordination mechanisms between the system operators and other stakeholders such as discoms, aggregators and consumers are in place. One example is in Rajasthan, where regulations recognise the need to work collaboratively with SLDCs and to identify constrained zones on the network (RERC, 2026).

The need for a national enabling framework for demand flexibility

Mainstreaming demand flexibility at scale requires a coordinated institutional architecture linking central and state-level actors under a shared long-term vision. State discoms, regulators and system operators are best placed to implement and operationalise it. To make state-level action consistent and scalable, however, central institutions must also anchor the standards, planning frameworks and market rules in national regulations. This calls for clearly delineated roles across the Bureau of Energy Efficiency, the Central Electricity Authority, the Central Electricity Regulatory Commission and the Ministry of Power, working in tandem with State Designated Agencies, State Electricity Regulatory Commissions, and discoms. We have outlined potential roles and responsibilities for these institutions below:

- **Bureau of Energy Efficiency (BEE):** Historically, BEE has been an instrumental player in mainstreaming demand-side management. To institutionalise demand flexibility across India, it can serve in a similar role by developing standardised operating codes, including load baselining, EM&V and interoperability protocols; integrating demand flexibility-ready criterion into the standards and labelling schemes for high-load equipment like air conditioners and EV chargers; and providing technical, financial and data-analytics support to institutionalise internal demand-side management cells in state discoms.
- **Central Electricity Authority (CEA):** As the central body responsible for national power system planning, CEA formulates long-term resource adequacy assessments. It can integrate demand flexibility metrics into this planning process, while setting technical and safety standards for grid-interconnected flexible loads.
- **Central Electricity Regulatory Commission (CERC):** The role of CERC is focused on regulating inter-state electricity transmission and generation tariffs, while overseeing the growth, rules and operations of national power markets. In collaboration with the Forum of Regulators, it can formulate model regulatory frameworks for third-party aggregation, wholesale market participation of demand flexibility assets, and uniform pricing and compensation signals, providing a common reference that state energy regulatory commissions can adapt for state-level implementation.
- **Ministry of Power (MoP):** As the apex policymaking body for the power sector, MoP is best positioned to mainstream demand flexibility by embedding it into the sector's overarching policy architecture. It can drive national and state-level policy alignment, issue national demand-side management and demand flexibility policy directives that give states a common mandate to act on and leverage central assistance schemes to incentivise state-level compliance and infrastructure-readiness. Additionally, MoP can connect demand flexibility to India's long-term national and climate goals, as an option for meeting renewable energy targets and net-zero commitments. This would help boost demand flexibility as a core tool for grid flexibility and decarbonisation, not just a peripheral efficiency measure.

Demand flexibility programme delivery

The growth potential for demand flexibility programmes depends on a combination of the regulatory enablers outlined in the earlier sections. This section outlines how these regulatory shifts translate to programme delivery in practice.[11,12]

It is most effective to sequence programme delivery according to flexibility potential and data availability. Commercial and industrial customers have greater flexibility than residential customers, making them a priority focus for near-term programme delivery. Any available smart meter data can help identify key customer segments and end uses. Residential customers may be best integrated through price-based and behavioural interventions that require limited investments in technology, before progressing to programmes with high upfront costs such as smart appliances, rooftop solar with behind-the-meter storage, and managed EV-charging programmes. Public infrastructure and agricultural consumers may offer flexibility potential in some states and will require distinct programme designs. Table 1 gives examples of programme delivery options and the regulatory enablers needed to realise their potential.

Table 1. Examples of programme delivery options and regulatory enablers for different customer segments

Programme delivery	Flexibility potential	Potential enablers
Residential: Time-varying tariffs, price incentives	Price-based demand response; shift loads manually in response to price signals or peak event notifications; particularly relevant for domestic consumers with higher loads such as cooling loads or EV chargers; may be most deployable ahead of smart metering infrastructure.	Time-varying tariffs or peak load reduction incentives; sustained participation and consumer awareness
Residential: Smart appliances including air conditioners and water heaters, home EV charging	Automated demand response and direct load control programmes; schedule appliances to run in low-power modes during peak times; pre-heat/pre-cool ahead of peak windows; adjust temperature setpoints or cycle compressors during peak periods; shift heating to off-peak or high-renewable windows; particularly relevant to domestic customers that have high loads and flexibility potential given the high upfront cost of investments; automated charging of EVs during non-peak and peak hours.	Time-varying tariffs; incentives such as appliance subsidies, financing mechanisms; device interoperability standards; consistent cost–benefit analysis frameworks for assessing the cost-effectiveness of programmes and designing incentives for utility-led programmes; aggregator participation frameworks that can help pool small distributed assets into a single controllable portfolio; consumer protection rules to ensure programme credibility and customer confidence.
Residential and commercial: Behind-the-meter storage with rooftop solar	Store excess solar generation and dispatch battery power during peak hours; promote grid reliability and resiliency; particularly relevant to customers that can pair with existing rooftop solar.	

[11] Additional programme designs might exist beyond these indicative categories, and innovation and technology are likely to further expand the available options.

[12] For more resources on programme delivery options see MP Ensystems, 2025, p.24.

Programme delivery	Flexibility potential	Potential enablers
Commercial and industrial: Critical peak pricing, interruptible supply agreements	Adjust or curtail consumption in response to prices during peak events or incentive payments.	Cost-reflective and state-specific time-varying tariffs; regulatory sandboxing and pilots to test price differentials and enabling technologies for different customer segments; coordination between discom and state load despatch centre; consistent guidelines for cost–benefit analysis to assess cost-effectiveness and incentive design for utility-led programmes.
Commercial: Automated demand response through commercial HVAC, smart appliances and lighting, building energy management systems	Automated demand response and direct load control programmes; adjust ventilation rates and temperature setpoints during peak grid events; dim non-essential lighting or switch to low-power modes based on occupancy/tariffs; automated optimisation.	Time-varying tariffs, device interoperability standards, aggregator licensing and participation frameworks to pool larger set of assets; cost–benefit analysis frameworks to evaluate cost-effectiveness and design incentives.
Commercial: Refrigeration and cold rooms	Reschedule defrost cycles; pre-chill stock and make minor temperature adjustments within safety limits (thermal inertia allows for flexible shifting without risking food safety).	
Commercial: Public EV charging and fleet management	Fleet scheduling and dynamic charging.	
Industrial: Heat use and process controls; industrial energy management systems	Interrupt or ramp down heavy machinery intensity; utilise automated industrial energy management systems for load management.	Load research based on available smart meter data identifying key customer segments and end users for participation; segment specific EM&V protocols; aggregator licensing and participation frameworks and aggregator-led pilots testing different business models; state load despatch centre and discom coordination mechanisms; consistent cost–benefit analysis guidelines for assessing cost-effectiveness and incentive design
Industrial: Demand bidding/wholesale market participation	Large customers can bid into wholesale markets, i.e., energy, capacity and ancillary services.	Technology-neutral market access and participation rules; aggregator participation frameworks, inclusion in centralised planning and procurement processes, i.e., resource adequacy and integrated resource planning frameworks.
Public infrastructure: Bulk water utilities	Pre-fill reservoirs and water tanks and run water pumps exclusively during low-tariff or high-renewable hours; defer network investment in constrained areas given high storage capacity.	NWA screening and procurement frameworks; discom and state load despatch centre coordination.

Programme delivery	Flexibility potential	Potential enablers
Agriculture: Smart micro-irrigation and automated pumping	Pre-run or shut off irrigation pumps during peak grid periods. Solar-powered pumps can completely island these users from the grid. Aligning pumping with solar hours lowers overall supply costs. Agricultural pumping may have higher potential in some states.	Appliance subsidies; cost-reflective price signals; regulatory sandboxing for tariff-setting and testing incentive structures; consumer education and awareness; leverage smart meter capabilities.

Path forward and next steps

Demand flexibility can play a critical role in integrating low-cost renewables and managing peak load growth, while delivering key benefits for security, affordability, reliability, resilience and sustainability. With a view to achieving these benefits, this section presents a roadmap and sequencing for regulatory enablers. The roadmap phases actions across four core enablers: customer participation and price responsiveness, utility-led flexibility programmes, aggregator integration, and parity between demand flexibility and traditional grid investments. Immediate priorities focus on building the evidence base and foundational regulatory frameworks. Short-term actions pivot to programme activation, including onboarding aggregators; launching utility-led, aggregator-led and NWA pilots; and developing institutional capacity. Long-term priorities focus on market integration, further building out NWAs and introducing dynamic pricing. These recommendations are detailed below.

Immediate priorities: Building the evidence base and regulatory architecture

In the near term, regulators can have the most impact by building the evidence base, establishing foundational regulatory frameworks, and supporting early-stage programmes for commercial and industrial customers with high flexibility potential. Regulators can refine these frameworks and programmes over time with experience and evidence. We recommend these enablers be prioritised immediately, with implementation within the next six months to one year. The strategic actions that serve these near-term goals include:

- **Design cost-reflective, efficient time-of-day tariffs:** Update existing time-of-day tariff structures to reflect the marginal costs of supply, including power procurement and distribution costs, which drive investment needs. Phase in time-of-day tariffs across customer segments, based on metering infrastructure and flexibility potential, with the goal of assessing price-responsiveness against different tariff design structures and informing subsequent tariff design.

- **Commission load research and potential studies:** Mandate discom-specific assessments of demand flexibility potential across customer segments and end use, as the basis for setting targets and identifying programme participants.

- **Build institutional capacity:** Invest in strengthening the capacity of discoms and regulators to design, implement and oversee demand flexibility programmes. This includes the capabilities to leverage smart meter data, design and run competitive procurement processes, manage aggregator relationships and oversee EM&V, all of which are best supported by standardised tools and access to international experience.

- **Create an enabling ecosystem for third parties and aggregators:** Enable third-party participation by establishing clear rules for licensing, registration and eligibility, with aggregators held accountable for performance. Address barriers that prevent aggregators from identifying and deploying flexibility cost-effectively, including grid transparency and interoperability protocols. Discoms should be encouraged to onboard third parties to activate demand flexibility.

- **Establish a customer data protection framework:** Require clear frameworks governing aggregator access to customer data. Ideally, this would allow third parties to access essential and non-personal consumption data through explicit consumer consent, as well as establish technical standards for data storage and security.

- **Develop frameworks for cost–benefit analyses and evaluation, measurement and verification:** Adopt jurisdiction-specific, cost-effectiveness tests and standardised processes, data and reporting requirements that promote consistency and comparability across discoms for programme evaluation. Use these cost–benefit analysis frameworks to screen programmes and design incentive structures. Mandate baseline validation to ensure that programme benefits are not overstated. The EM&V process conducted during and after implementation then verifies whether the programme has delivered the projected benefits and feeds the lessons back into the design of subsequent programmes.

- **Establish coordination mechanisms for discoms and State Load Despatch Centres:** Establish data-sharing protocols and coordination mechanisms between discoms and State Load Despatch Centres to ensure demand flexibility is dispatched where and when it delivers the most system value. This process includes exploring direct competitive procurement of demand flexibility products by State Load Despatch Centres to meet system needs.

- **Support early-stage commercial and industrial pilots:** Introduce a limited number of well-designed programs for commercial and industrial customers with robust EM&V requirements to establish reliable megawatts and identify actual programme costs, supported by clear and publicly available reporting requirements. Pilots can focus on different designs and delivery mechanisms.

Short-term priorities: Programme activation

With foundational frameworks in place, short-term priorities shift toward activation: testing programme designs, building capacity, and generating evidence at scale. We recommend these actions be prioritised in the next one to three years.

- **Run customer education and awareness campaigns:** Build consumer awareness and trust in demand flexibility programmes and tariffs, focusing on targeted actionable guidance for consumers. This step is essential for sustained participation. Allow cost recovery for customer education and awareness campaigns.

- **Scale successful programmes and continue support for pilots:** Expand the reach of successful programmes. Continue broadening delivery mechanisms and extending them to a larger customer base through utility-led and aggregator-led models.

- **Support non-wires alternatives pilots:** Trial demand flexibility in targeted, capacity-constrained locations as an alternative to new network investment. Develop screening and evaluation frameworks, to be refined over time through pilots.

- **Set evidence-based targets and accountability mechanisms:** Use load research and results from pilots to set measurable and achievable targets for discoms. Targets should be backed by clear reporting and accountability mechanisms.

- **Introduce performance-based regulation:** Adopt performance-based incentives and revenue decoupling mechanisms that align discom incentives with prioritising demand flexibility over new infrastructure.

Medium-term priorities: Achieving system parity and deep market integration

Over the medium term, the focus shifts to fully integrating demand flexibility into electricity markets and planning. We recommend this be prioritised in the next three to five years.

- **Deploy non-wires alternatives at scale:** Make NWAs a standard planning tool, with ongoing tracking of performance against conventional network investment and clear accountability mechanisms.

- **Integrate demand flexibility into resource adequacy planning:** Formally account for demonstrated demand flexibility capacity in resource adequacy planning using established methodologies that reflect dependable performance during critical hours.

- **Provide non-discriminatory market access:** Address specific operational barriers that prevent demand flexibility from participating in existing markets. Progressively allow demand flexibility to compete on a level playing field with conventional resources across energy, capacity and ancillary services markets.

- **Introduce granular, dynamic price signals:** Move toward more granular and dynamic – including real-time – pricing that reflects system conditions more precisely, particularly for large consumers.

- **Expand aggregator participation:** As aggregator frameworks mature, gradually open routes for aggregators to contract directly with system operators and access multiple value streams. This will support the shift from discom-mediated models to direct market participation as regulatory and market infrastructure develops.

Realising the full potential of demand flexibility will require combined and sustained efforts from numerous stakeholders. A phased approach can evolve it from use in isolated pilots into a mainstream grid resource. Flexibility is a powerful tool for supporting the cost-effective integration of renewable energy while strengthening the affordability, reliability and resilience of the power system.

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Annex A. Potential avoided costs and valuation methodologies

Annex A provides a summary of avoided costs and the underlying methodologies for estimating them. The monetary estimates are indicative, drawn from studies of various energy systems. In practice, the values will be jurisdiction-specific.

Avoided cost	Valuation	Methodologies
Energy: Reduced cost of procuring energy due to load reduction or load shifting from high-cost periods to low-cost periods.	~INR 10–20 /kWh during peak hours[13]	Value is highly jurisdiction-specific and depends on actual peak power purchase costs, future fuel costs, and variable costs. The referenced avoided energy cost is based on Indian Energy Exchange (IEX) price caps in the day-ahead market (DAM) and high-priced day-ahead market. More granular data can be derived through production cost modelling. For demand shifting, the avoided cost of energy is the difference between the reduced cost of not withdrawing energy and the extra cost of withdrawing later.
Generation capacity: Reduced investment in capacity to address peak demand growth through peak load reduction or load shifting away from critical hours that drive investment needs.	INR 16,200/ kW-yr[14]	Annualised cost of the marginal generation capacity addition, based on the cost of new power plants providing firm capacity. Results are sensitive to assumptions on the discount rate, utilisation, and the choice of marginal technology. This value is estimated based on the cost of new coal plants.
Distribution capacity: Deferral or elimination of costly upgrades to the distribution infrastructure (and associated operation and maintenance costs) through reduction or shifting of demand from constrained network periods or locations.	INR 3,658/ kW-yr[15]	Annualised capital expenditures that can be deferred or eliminated (e.g., load growth and reliability investments), based on jurisdiction-specific forward-looking capital expenditure plans. The actual deferral value will depend on the specific investment, the timing and the quantity of demand reduction or reliability that can be delivered. Here, distribution infrastructure capital expenditure is taken as INR 25 million/MW, with annual operations and maintenance costs estimated at 5%.
Transmission capacity: Deferral or elimination of costly upgrades to the transmission infrastructure (and associated operation and maintenance costs) by reducing load or shifting of demand from constrained periods or locations.	~ INR 1,500/kW-yr[16]	Annualised capital costs that can be deferred and should be based on forward-looking capital expenditure plans. Here, transmission infrastructure capital expenditure is assumed to be INR 10.5 million/MW.

[13] IEX, 2026.

[14] Annualised cost of a new coal plant calculated assuming a 10% discount rate annualised over 25 years (CEA, 2026a).

[15] Annualised cost of distribution infrastructure is calculated using information from literature: a 70:30 debt-to-equity ratio, a 9% nominal interest rate, and a 25-year asset lifespan, O&M of 5% (AEEE, 2025).

[16] Calculated using a 70:30 debt-to-equity ratio, 9% nominal interest rate, 25-year asset lifespan, annual O&M at 5%. Transmission infrastructure capital expenditure is taken as INR 10.5 million/MW (CEA, 2022).

Avoided cost	Valuation	Methodologies
Grid services: Reduction in deviation settlement charges, balancing and reserve procurement costs.	~INR 19/kWh[17]	The value of grid services is based on the market value of ancillary services or the annualised cost of building and operating resources to meet ancillary needs such as frequency regulation, spinning reserves and balancing energy. There is limited data for ancillary services in India given the bundled procurement of different services within power purchase agreements, which makes the value difficult to disaggregate. Estimates here represent the cost of operating gas plants. Deviation settlement charges are highly specific to jurisdictions.
Distribution losses: Reduced distribution losses through peak load reduction or shifting of demand to off-peak periods when network loading and marginal losses are lower.	>13.48%[18]	Avoided losses are valued at the marginal cost of energy and derived from the marginal loss rate within the relevant jurisdiction. When network load is higher, the losses are also higher. Demand flexibility that shifts load to off-peak periods may reduce marginal losses. This data is indicative and is based on average distribution losses across discoms. Marginal losses can be significantly higher. Values will be highly jurisdiction-specific. For example, in the U.S., marginal losses can be as high as three times the average losses or more.[19]
Transmission losses: Reduced transmission losses on system through peak load reduction or shifting of demand to off-peak periods when network loading and marginal losses are lower.	~ 5%[20]	Similar to distribution losses, these are generally estimated based on the marginal loss rate within the relevant jurisdiction. This data is based on peak demand transmission losses.
Environmental compliance: Reduced cost of compliance with environmental regulations and standards by displacing thermal generation.	Limited quantifiable data for India	Highly jurisdiction-specific, there is only limited data available in India. This can be estimated as the avoided cost of meeting environmental obligations such as air quality standards.

[17] Grid India, 2026b.

[18] Note: Median calculated from the 65 individual distribution utilities' distribution loss values for FY 2024-25, provided in the 14th Integrated Rating and Ranking of Power Distribution Utilities. With 65 values (an odd count), the median is the 33rd value when sorted in ascending order, i.e., distribution loss of 13.48% (MoP, 2026c).

[19] Marginal loss numbers based on Wiser & Mills, 2014.

[20] Soonee et al., 2026.

Avoided cost	Valuation	Methodologies
Reliability: Reduce or prevent load shedding and outages and maintain the power system to withstand disturbances.	~INR 125/kWh for domestic consumers.[21] Significantly higher Value of Lost Load for commercial and industrial customers.	The avoided reliability cost is typically estimated using the Value of Lost Load (VoLL). This can be derived from consumer surveys assessing willingness to pay to avoid outages or by quantifying the economic output lost during supply interruptions. VoLL presented is based on domestic consumer surveys only and does not include reliability value to commercial and industrial consumers, which is likely to be higher due to production losses, equipment restart costs etc. These can be highly industry-specific and can also be proxied based on the costs incurred to procure backup generation.
Greenhouse gas emissions: Reduced emissions.	Limited quantifiable data for India	Social Cost of Carbon estimates in 2030 based on studies conducted by the U.S. Environmental Protection Agency, for example, is $230/tonne.[22] This data represents the global social cost of carbon and is a widely referenced value. However, the actual carbon value will depend on the specific policy framework and should be subjected to sensitivity analysis. Other pollutants such as methane, sulphur oxides, nitrogen oxides and particulate matter are also avoided.
Energy security/Resilience: Reduced exposure to fuel volatility, weather events.	Limited quantifiable data for India	Energy security cost is difficult to quantify and is often treated qualitatively. This can be estimated based on reduced exposure to fuel price volatility. Resilience can be quantified based on the avoided cost of backup resources that would need to be installed to meet uncertainty. Limited data is available in India for quantification; qualitative recognition is recommended at minimum.

[21] Khanna & Rowe, 2024.

[22] Expressed in 2020$ and based on 2% discount rate. Does not include the social cost of methane and nitrous oxide (U.S. EPA, 2023).

Annex B. Assessment of state demand flexibility regulations

Policy	Assam	Karnataka	Maharashtra	Rajasthan
Adoption of time-varying tariffs	Certain commercial and industrial segments have time-of-day tariffs; recognise the need for tariff-based incentives	Certain commercial and industrial segments have time-of-day tariffs.	Certain commercial and industrial segments have time-of-day tariffs.	Certain commercial and industrial segments have time-of-day tariffs; demand flexibility regulations recognise the need for tariff-based incentives.
Initiate customer education and awareness	Requirement for discoms to earmark costs for consumer education and outreach.	No directives on customer education and awareness campaigns.	No directives; cost recovery allowed for consumer education and outreach.	Directed to conduct consumer outreach and awareness; cost recovery allowed for consumer education and outreach.
Set evidence-based targets tied to long-term system priorities	Electricity Regulatory Commissions to set targets based on discom-led demand response potential and load research; the priorities for demand response are outlined.	Discoms are directed to conduct load research to inform programmes; information should be publicly available; cost recovery for studies is allowed. Electricity Regulatory Commission established Demand Flexibility Portfolio obligations as a percentage of peak demand.	Discoms are directed to conduct load research based on smart meter data to inform programmes; information should be publicly available; cost recovery for studies is allowed. Electricity Regulatory Commission established Demand Flexibility Portfolio obligations targets as a percentage of peak demand.	Discoms are directed to conduct load research to inform programme design; information should be publicly available; cost recovery for studies is allowed. Electricity Regulatory Commission established Demand Flexibility Portfolio obligations targets based on peak demand.
Financial penalties for underachieving target	No specific financial penalties are established.	Yes. Regulations impose a flat penalty/incentive of INR 2 million per MW deviation from the target. No clarity on how penalty is derived.	Imposes a flat penalty/incentive of INR 2 million per MW deviation from the target. No clarity on how penalty is derived.	Yes. Adopts the INR 2 million penalty/incentive per MW rule but defers penalties for Year 1 (Preparatory Year). No clarity on how penalty is derived.

Policy	Assam	Karnataka	Maharashtra	Rajasthan
Adoption of performance-based regulation/revenue decoupling mechanism	Not addressed.			
Regulatory support for capacity building	Discoms required to establish demand-side management cells that are responsible to drive implementation; must be headed by Chief General Manager. Officers are not to be assigned other simultaneous duties to ensure dedication to demand response and shall have minimum tenure of three years.	Discoms required to establish demand flexibility/demand-side management cells that are responsible for monitoring and reporting of programmes to the Electricity Regulatory Commissions.	Electricity Regulatory Commission to setup a demand-side management consultation committee to support Commission and require licensees to form a demand-side management cell with clearly defined terms of reference for its activity and adequately staff their demand flexibility and demand-side management departments.	Discoms required to establish demand flexibility/demand-side management cells that are responsible for targeted activities for demand flexibility implementation and are headed by senior officer.
Regulatory support for pilots	Discoms directed to design, develop and implement pilots for consumers with smart meters.	No specific directives on pilots, however standardised demand flexibility/demand-side management portfolio and implementation action plan are required alongside the multi-year tariff filings; implementation and status reports of implemented programmes are required to be public.	No specific directives on pilots, however standardised demand flexibility/demand-side management portfolio and implementation action plan are required; implementation and status reports of implemented programmes are required to be public.	No specific directives on pilots, however standardised demand flexibility/demand-side management portfolio and implementation action plan are required alongside the multi-year tariff filings; implementation and status reports of implemented programmes are required to be public.

Policy	Assam	Karnataka	Maharashtra	Rajasthan
Establish clear cost-benefit analysis frameworks	Discoms directed to provide cost-benefit analysis; no specific screening guidelines.	Cost-effectiveness testing guidelines established; total resource cost test and ratepayer impact measure test for decision-making; both should show positive net present value; only avoided cost of power purchase and reduced transmission charge are considered as a key benefits.	Cost-effectiveness testing guidelines established; total resource cost test, ratepayer impact measure test, and life-cycle revenue impact test for decision-making; avoided cost of power purchase. reduced transmission charge and ancillary benefits recognised for testing .	Cost effectiveness testing guidelines established; total resource cost test, ratepayer impact measure test, and life-cycle revenue impact test; avoided cost of power procurement, reduced transmission charges and avoided infrastructure upgrades recognised as benefit for testing.
Establish clear guidelines for EM&V	No EM&V procedures established in the regulation.	EM&V procedures have been established; reports are required to be public.	EM&V procedures have been established; reports are required to be public.	EM&V procedures have been established; reports are required to be public.
Establish clear frameworks for participation of third-party aggregators	Aggregators can be appointed by discoms. Provides guidelines on adoption of network and technical standards; Central Electricity Authority and Bureau of Indian Standards are to be adopted where applicable; discoms must provide a certificate of compliance for equipment installed.	Demand flexibility programmes can be implemented by discoms or aggregators appointed by discoms.	Demand flexibility programmes can be implemented by discoms or aggregators appointed by discoms.	Demand flexibility targets can be met by procuring capacity from aggregators; discoms directed to issue frameworks for aggregators; discoms to create and maintain a digital registry of aggregators.
Protecting customer data	Provides guidelines for consumer data protection.	No guidelines included.	No guidelines included.	Programmes are to be implemented with safeguards to protect consumer interests and privacy; refers to Digital Personal Data Protection Act, 2023.

Policy	Assam	Karnataka	Maharashtra	Rajasthan
Demand flexibility as a grid resource	Non-wires alternatives not included, regulations recognise demand flexibility contributions to resource adequacy, no reference to discom and SLDC coordination for implementing demand flexibility.	Non-wires alternatives not included, regulations recognise demand flexibility contributions to resource adequacy, no reference to discom and SLDC coordination for implementing demand flexibility.	Non-wires alternatives not included, regulations recognise demand flexibility contributions to resource adequacy, no reference to discom and SLDC coordination for implementing demand flexibility.	Non-wires alternatives not included, regulations recognise demand flexibility contributions to resource adequacy, discoms are directed to coordinate with SLDC to implement demand flexibility.

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