To grant these new participants equal access to compensation for flexibility, authorities need to review and possibly reform the current state regulations and market rules. The first step for state regulators is to identify the barriers to competition that these new technologies face. More specifically, storage (including batteries) faces barriers to enter and compete in the current regulatory setup. For example, state rules need to specify if battery investors are eligible for fixed-cost payments in a similar way to thermal assets. At the same time, the development of new ancillary services and an ancillary services market provides an opportunity to consider all technologies, new and established, from the outset.

Additionally, state grid codes can be reviewed and updated to specify system-friendly connection and flexibility requirements for new solar and wind projects, including distributed solar (rooftop and pumps).

Comprehensively reviewing and removing the (wholesale and retail) market barriers to new technologies is an important ongoing task worldwide. For example, the United Kingdom is revising its balancing services and capacity markets in parallel processes. Australia has made interim accommodations and proposed rule changes for utility-scale batteries while consulting on its post-2025 market design. The Canadian province of Ontario is identifying obstacles to fair competition within its current markets for energy storage resources and is proposing mitigation strategies through an advisory group. France's energy regulator has also started reviewing the technical rules of the capacity mechanism from the perspective of battery storage resources. The EU's Electricity Market Design legislation mandates competitive procurement of flexibility services and fair rules for network access and charging, but whether it could more broadly reduce barriers to energy storage depends on how the legislation is implemented by its members.

Comprehensive market reform is also taking place in the United States. The US Federal Energy Regulatory Commission (FERC), which regulates the wholesale electricity markets and high-voltage transmission system, has issued a ruling to review its market rules and remove unnecessary barriers to energy storage participation. This ruling opens the door to all types of energy storage resources sited anywhere on the power system participating in energy, capacity and ancillary services markets. Ideally, these markets would drive technological innovation, but current electricity market rules are largely tailored to legacy power plants, which can inhibit progress. Historically, market rules have been tailored to the operating parameters of traditional power plants such as large hydropower and gas peaker plants, not smaller storage technologies. For example, some grid operators in the United States imposed minimum size requirements of up to 1 MW, which excludes smaller batteries.

The FERC's ruling also invites storage resources located on the distribution system (potentially behind the meter) to participate in the wholesale electricity markets. Again, therein lies the main controversy. While FERC can open the gates to its wholesale electricity markets and the high-voltage transmission system, states and other local authorities regulate the distribution system (a dichotomy formalised in the 1935 US Federal Power Act). States and other local entities have therefore challenged the FERC rule.

The tension between federal and state authorities is a common theme with newer, smaller resources like demand response, storage and distributed energy that could provide services to both the transmission and distribution systems. Similar issues arise in other two-tiered jurisdictions in Australia, Canada, the European Union and India.

Wholesale power market reforms improve liquidity

Wholesale power exchanges in India have improved greatly since their introduction in 2008 and have become the most significant in the South Asian region. Most of the short-term traded electricity volume (over 95%) is traded on the India Energy Exchange (IEX) as of 2020.

India's wholesale markets have been historically criticised for their lack of liquidity and products. Liquidity is still low, but there is an improvement in product availability.

In India the sale of power typically happens in three timeframes. Firstly, long-term arrangements include contracts of over seven years' duration and cover power generators entering into PPAs with a DISCOM or state government to sell power for a fixed period of time as per the tariff determined by the regulator, or discovered through competitive bidding. The purpose of these long-term contracts is to ensure that new generation capacity will be built. In India, the states and DISCOMs use these contracts to ensure resource adequacy in the long term because they do not have alternative resource adequacy arrangements.

Secondly, medium-term arrangements – typically between one- and five-year durations – cover generators selling power based on competitive bidding through an Indian marketplace portal for DISCOMs and generators. The size of this market is negligible in India.

Thirdly, short-term markets for contracts below one year cover bilateral, multilateral or exchange-traded contracts between buyer and seller. The two power exchanges in India include the IEX and Power Exchange India Limited (PXIL). The short-term markets in India account for around 10-11% of the market volume.

In 2020 the pandemic and the related decline in demand had a significant positive impact on the volume of electricity wholesale trade on power exchanges in India. Wholesale prices were approximately 20% to 29% lower than the previous year at INR 2.7/kWh on average in September and closer to INR 2.5/kWh between March and September (in the range of INR 2-4/kWh). The traded volume increased compared to the previous year; this increase was around 44% in September 2020 for all market segments – for example, the day-ahead market, term-ahead market, real-time market and green term-ahead market. The increase in volume was driven by multiple factors: utilities preferred short-term trade as opposed to business-as-usual 3- to 9-month contracts in light of unforeseeable demand patterns. Additionally, utilities offered the unserved volume resulting from lower electricity demand for sale in the market. Finally, driven by lower prices, some utilities replaced their contracted generation with cheaper market purchases. Day-ahead market volume was typically around 180 000 MWh per day in 2020.

Real-time power markets were launched in June 2020 in India. The IEX has witnessed this market becoming a success and filling an important gap by providing real-time trade (two 15-minute blocks an hour ahead) for intermittent and variable generation such as solar and wind. The price volatility of the real-time market has been greater than that of the day-ahead market, but on average, prices are typically lower, at INR 2.36/kWh. Real-time market volume was typically around 20 000 MWh/day. The principal users of real-time markets include more than 50 DISCOM buyers, over 200 industrial buyers and more than 20 generation companies, while sellers included nearly 40 DISCOMs, over 140 thermal plants and nearly 30 hydropower plants.

The green market was launched in August 2020 at the IEX, where green electricity has been trading at a premium (compared to the regular day-ahead market) in a range of INR 3-3.8/kWh for clients looking to fulfil their renewables purchase obligations through market purchases. Green market trading volume is currently averaging around 10 000 MWh per day.

The new market products are meant to fill the gaps in the Indian wholesale market design and contribute to improvements in product variety and market liquidity.

PPA flexibility can improve system flexibility by separating the financial from the physical

Long-term PPAs represent about 90-95% of the electricity market in India. As a result, India is highly dependent on PPAs that cover physical delivery of energy and capacity. Physical PPAs in India are widely seen as a key reason for low liquidity in short-term markets and they also pose a barrier to improved power system flexibility (both from trade and from conventional power plants). In order to integrate VRE, short-term flexibility is key and physical PPAs can be a major barrier to utilising technical flexibility already present in the system.

The DISCOMs tend to use the physical PPAs to secure the long-term resources needed to meet projected peak demand due to the lack of dedicated resource adequacy mechanisms in the states. However, based on international experience, linking the physical PPAs to resource adequacy may not be the most cost-effective tool for achieving resource adequacy, thus states could consider creating alternative resource adequacy mechanisms.

The reasoning behind using physical PPAs is that they ensure the bankability of projects, which can then obtain financing. However, PPAs do not need to be physical to ensure financing; they can also be financial. In other markets around the world we also see PPAs as a key enabler of project bankability, but in markets such as Europe or the United States, these PPAs are often financial. The counterparts of these types of contracts can be anything from traders to utilities, to corporate entities. Within the European context, generation can have two separate contracts: a financial contract ensuring budget stability, and a physical contract ensuring the sale of the physical power in the short-term markets. In this way the daily optimal dispatch is ensured via the physical contract, while the long-term financial viability is ensured via the financial PPA. Currently in India the fact that financial stability is not separated from daily physical scheduling is a barrier to system flexibility and the integration of VRE. Financial PPAs ensure the budget stability of projects without interfering in the day-to-day physical scheduling of assets. In this way, assets can still be activated according to the merit order and have budget stability.

An alternative to a system of bilaterally negotiated contracts is to create a financial market with exchange-traded financial products that can be used for budget stability on both the consumption and production sides. For a financial market to be successful, a good reference price needs to be established and buyers (DISCOMs) need an investment-grade credit rating. In lieu of a good credit rating, collateral can be used when trading financial products; however, collateral is a relatively expensive option, and might be difficult for financially stressed DISCOMs to post. It is important to note that the financial stability of the DISCOMs is a barrier for all PPAs, whether they are physical or financial in nature, but within financial contracts the collateral or credit agreements can be more formalised since there is no physical production behind the contact.

As mentioned, the reference price is an important feature for well-functioning financial markets. The reference price in the European financial markets is the day-ahead price, which is sufficient since the price formation of the day-ahead price in Europe is stable and liquid. There is currently no stable reference price in India, which means that bilateral financial PPAs might be the better option to allow short-term flexibility via participation in the short-term markets for the generation assets, at least until liquidity in the short-term markets has improved.

In the longer term, a sophisticated financial power market could be introduced in India. Currently there is no financial power market, but during several events in which the IEA has participated, stakeholders have mentioned their ambition to launch a financial market. Most financial power markets have both exchange-traded products and over-the-counter products. The list below shows some of the financial products that are used internationally to ensure the financial stability of generation assets as well as consumption portfolios. These products are used by utilities, generators and consumers alike.

The reason for considering financial instruments in India is to ensure that the long-term budget stability of generation assets does not affect short-term scheduling. If the existence of physical PPAs changes the merit order, the efficiency of the power system is compromised and that limits the flexibility and ability of the system to integrate renewables. A tool to ensure that this does not happen is a system of financial contracts coupled with agreements to sell the physical generation on the short-term markets.

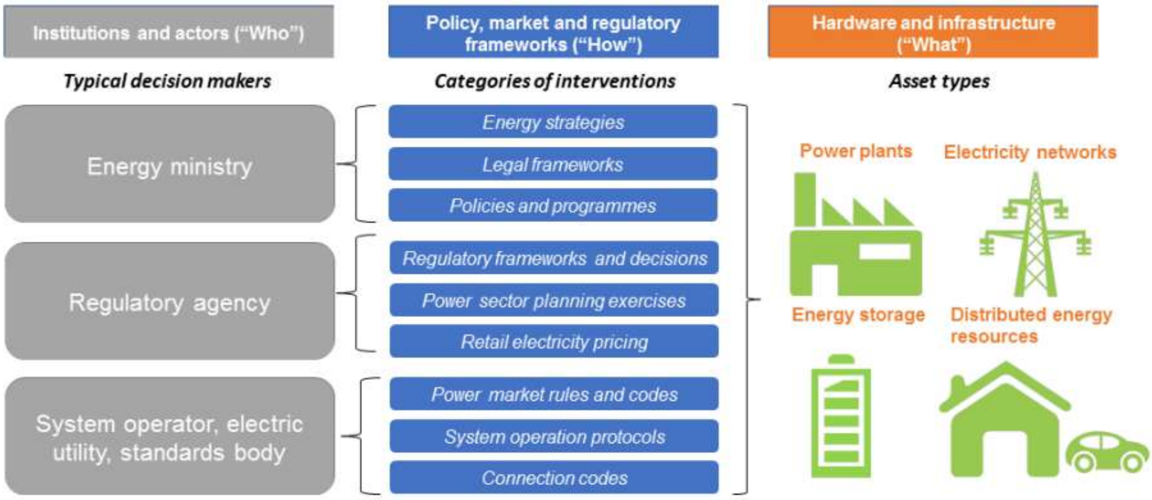
Overview of international electricity contract types

Type of power contract	Description	Example
Forward	Bilateral or exchange-traded contract for fixed amount of power; can be either physical or financial	PPA, typically for baseload technologies or used for hedging structured products such as swaps
Swap	Fixed-price forward bilateral contract	Contract for difference, fixed-price PPA with volume flexibility
Tolling agreement	Bilateral agreement where the off-taker acts as the market scheduler for a power plant	Asset owner is paid a fixed rate to toll the asset to a second party who then has the production and price risk of the asset
Future	Standardised exchange-traded contract for future delivery; typically never delivered – a financial settlement-only contract	Typically same types of application as a forward
Option	Bilateral contract that gives the off-taker the option to buy or sell power, or earn revenues from a generator; they can be financial or physical	Heat rate call option, revenue put option; collar option that provides a floor and a ceiling for earnings from an asset; renewable assets can also use weather derivatives to secure volumetric risk

Policy recommendations

Similar to the existing power system, the current policy environment was designed for India's coal-dominated power sector. With the clean energy transitions, the entire policy environment is being reviewed and redesigned in many countries; this includes the government institutions in the power sector and the policy, market and regulatory frameworks at both the national and state level in India.

The three layers of power system transformation



These key policy recommendations are valid in the wider context of the full report and should not be taken out of context. They look at critical missing elements of the policy framework required for each flexibility option, noting that the optimal combination of these flexibility resources must be determined for each state, taking into account the regional and national context.

Curtailment

1. Improve investor confidence surrounding curtailment risk through ongoing policy dialogue on the future of must-run status of solar and wind, as well as contractual structures and policies related to curtailment and compensation. It is also desirable to improve the transparency and public availability of curtailment data (annual, monthly solar and wind curtailment for each state) and provide more specific reasons for curtailment decisions made by SLDCs.

Demand response

2. Build a regulatory framework and pricing mechanisms to enable the shift towards more proactive participation by demand sectors than their existing passive consumption.

Making load curve data per DISCOM and per consumer type for each state transparent and public would help private and public sector players calculate the return on investment in demand-response programmes and assess their optimal tariff choices.

Accelerating the rollout of advanced metering infrastructure is a prerequisite for demand response. Smart meters need to be coupled with other digital tools such as displays, notification systems and systems providing automation to provide demand response. In the residential sector, a shift towards advanced digital metering and smart home appliances is a prerequisite for the use of TOU tariffs and demand response.

Shifting all users, including residential users, to default TOU tariffs is recommended in the longer term, particularly consumers with rooftop solar, EVs and smart charging in buildings.

To enhance cooling demand response, alongside deployment of advanced metering infrastructure, the government could provide targeted economic incentives for commercial and residential consumers, allowing limited time shifting of cooling loads without significant impacts on the consumer experience. It could also support provision of some form of communication and control for air-conditioning devices, and develop viable business models for district cooling in the Indian context.

To strengthen agricultural demand response, the availability and use of dedicated agricultural feeder systems to shift agricultural demand to solar generation hours in renewables-rich states could be extended.

Rooftop solar

3. Improve the visibility of rooftop solar assets in India. Based on international examples, the Indian states can consider options to improve the visibility of rooftop solar systems.

- State regulators could appoint an entity to develop a distributed solar registry platform available to state DISCOMs, with registration of solar pump and rooftop solar systems to be included in (new and amended) connection requirements. The registry data would ideally be publicly available in an anonymous format and data should also be made available by the DISCOMs to the SLDC. In parallel, the DISCOMs would require consumers to register new installations of distributed solar equipment on the above-mentioned platform.

- DISCOMs can also develop a roadmap for distributed solar forecasting and assess the technical requirements and potential policies to support more rooftop solar uptake, such as TOU tariffs (included in the following section).
- Adding reactive power and voltage control capabilities to connection requirements embedded in the DISCOM and transmission connection codes can help rooftop solar become a system-friendly resource.
- Consideration could be given to the application of export limits to the distribution system (to be varied depending on how much can be accommodated at specific times) through a software-based approach called dynamic operating envelopes. This is a solution to prevent reverse flows in distribution networks due to increasing shares of grid-connected rooftop solar PV.

Tariff reforms and introduction of TOU tariffs

4. Implement tariff reforms, focusing on the revision of electricity tariff design and tariff options as one of the most important future tools to enable more demand-side flexibility in India. This would shift significant user volume from times of low solar output to times of high solar output and thus save system-level costs that could lead to greater affordability. Consider including tariff reforms that expand TOU pricing to more customers, adjusting the peak tariff slots and switching more users to default time-dependent tariffs.

5. The installation of smart meters coupled with other digital tools to provide demand response could create a foundation for the introduction of TOU tariffs in Indian states. Key enablers for TOU implementation include institutional strengthening, innovative business models, and consumer awareness and engagement programmes.

Energy storage

6. Develop a regulatory and remuneration framework for energy storage with specific reference to battery storage and pumped-storage hydro to capture their full value. National and state policies should include a definition of energy storage, including its size, technical capabilities, flexible nature and applications, and its categorisation as a generation, transmission and/or distribution asset, as has been done in the United Kingdom. Policy and regulatory barriers for batteries and pumped-storage hydro should be removed to ensure that they can take advantage of energy arbitrage opportunities from shifting energy demand within a day or week, and contribute to ancillary services for managing system ramps.