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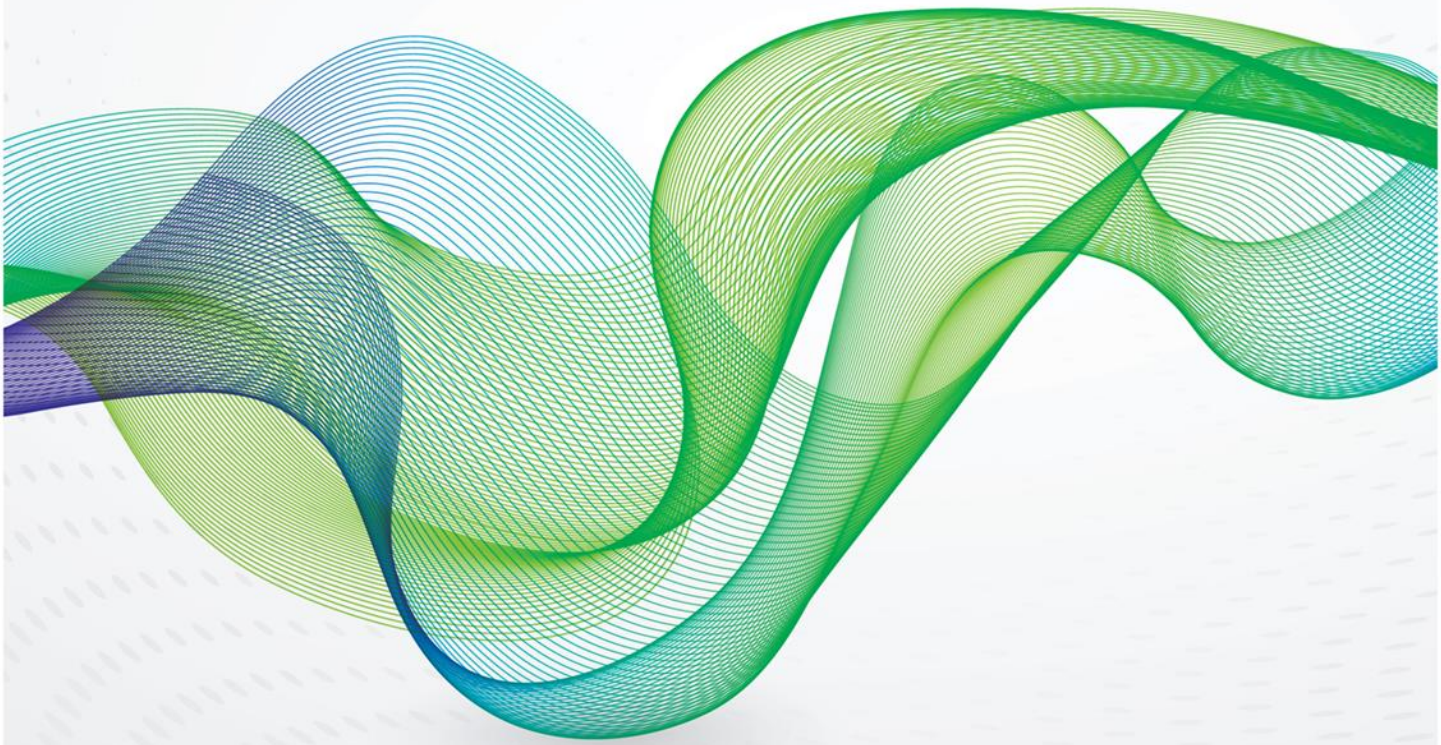
The Rise of Distributed Energy Resources:
A Case Study of India's Power Market



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Rahmatallah Poudineh, Senior Research Fellow, OIES ,
Mohua Mukherjee and Gabriela Elizondo

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Abstract

As the world's third-biggest emitter of greenhouse gases, India has pledged to achieve net-zero carbon emissions by 2070. The electricity sector is at the forefront of decarbonisation initiatives and distributed energy resources (DERs) are expected to play a key role in enabling the country to eventually transition away from fossil fuel power generation (especially coal). DERs are physical or virtual assets that are located close to demand across the distribution grid, and can provide value to the power system, individual customers, or both. As the share of traditional flexible fossil fuel generation declines in the power mix, distributed generation, energy storage, and demand response will become important sources of system flexibility. Specifically, the rise of EVs (electric vehicles) and of electricity demand for cooling services provide significant opportunities for decentralized flexibility. However, the Indian power sector requires a range of reforms to bring it into line with the rise of the decentralization paradigm. These include in the areas of market architecture, coordination between transmission and distribution network operators, reforming the distribution sector and rationalisation of retail tariffs.

In terms of market architecture, the country needs to move towards a two-sided market in which both supply-side and demand-side resources can participate. This requires removing barriers to the entry of aggregators, investment in ICT infrastructure and distribution grid modernization, and the establishment of liquid short-term electricity markets, local flexibility markets, and ancillary service markets. Also, a more effective coordination mechanism between transmission and distribution network operators is needed to improve visibility and control over DERs and enable a better utilization of these resources for both local grid congestion management as well as national grid balancing. The more complex issues, however, lie in the distribution sector. The current scope of distribution licensees' operation includes both network and retailing, which means that the state distribution companies (Discoms) will not benefit from customer-owned DERs; they thus have an incentive to resist their uptake. The State Discoms are also in poor financial health due to a range of factors such as poor management, non-cost reflective retail tariffs, and a high level of AT&C (aggregated technical and commercial) energy losses. This prevents them from investing in grid modernization and digitalization. Finally, retail tariffs in India are lower than the actual costs of supply for residential consumers; this makes investment in DERs uneconomic for this class of customers, whereas a higher rate incentivizes grid defection among C&I (commercial and industrial) customers, with consequences for the revenues of distribution utilities.

Contents

Figures

Tables

1. An overview of the electricity market in India

The Indian electricity sector has evolved significantly over the last few decades from a vertically integrated monopoly to an unbundled sector (at the transmission level only), with private sector participation and competition in generation (and transmission via auctions), and an integrated national power grid that interconnects five previously disintegrated regional transmission grids.

The Electricity Act 2003 (EA 2003) is the key legislation that shaped the current structure of India's electricity market by introducing a series of fundamental reforms – delicensing generation, enabling third-party access to the transmission network, and facilitating electricity trade among market participants (Rudnick and Velasquez, 2018).

Governance of the electricity sector in India is 'concurrent', meaning that the sector is jointly managed by States and the Federal government. As a result, states are not obligated to follow federal policies with respect to the power sector, and state electricity regulators can decide what reforms to implement.[1] From the 1950s up to the early 2000s, each state had had a vertically integrated State Electricity Board; these were unbundled after EA 2003, resulting in state-specific generation, transmission (intra-state), and distribution inside each state.[2] Apart from Kerala and Tamil Nadu, most other states have a state generation company (GenCo), a state transmission company (operating only inside the state boundaries), and a state distribution company (Discom). The central government, on the other hand, owns the national power transmission grid and few GenCos (most notably NTPC). There are no federal Discoms except for the eight 'union territories' which are run by the federal government.

The wholesale electricity market in India is primarily a physical bilateral contract market (see Figure 1). Power purchase agreements (PPAs) are the most common method of entering into contractual arrangements between generation companies and distribution utilities. There are also auctions for allocation of long-term contracts, as well as power exchanges for short-term trading, albeit with a limited share of total transactions. Long-term contracts (typically between 7 and 25 years) and medium-term contracts (between 1 and 7 years) constitute almost 90 per cent of the current electricity trade, while short-term bilateral contracts (less than one year) and power exchanges (day ahead and week ahead) make up the remaining 10 per cent. Since 2011, renewable energy certificates (RECs) have been traded in the power exchange and it is expected that energy saving certificates will also be introduced in the future.

Despite the progress that has been made to date, significant further improvements are required to ensure that the power market structure and regulations are in line with government renewable energy objectives and recent developments in the sector.

The government of India (GoI) has set an ambitious target for 2030 which includes reducing CO_2 emissions by 33–35 per cent from 2005 levels and increasing the share of renewable energy in the generation mix to 40 percent (IEA, 2020). By 2022, GoI plans to install 175 GW of renewable energy capacity, of which 100 GW is solar, 60 GW is wind, 10 GW is biomass, and 5 GW is small hydro power. In order to maintain the target of 40 per cent renewable energy while the overall generation capacity of the country grows, the 175 GW target is proposed to be raised to 450 GW in subsequent years. At the

[1] At the central level, the Ministry of Power is responsible for the policy-related aspects of the sector, while responsibility for overall sector planning is given to the Central Electricity Authority (CEA). The Ministry of Power, the CEA, and the Central Electricity Regulatory Commission (CERC) provide policies and guidelines, and the state authorities issue their own respective state policies and regulations, often based on those guidelines. Therefore, state power sector policies and outcomes are not necessarily similar. Central agencies are involved in issues that involve more than one state, while decisions about matters within the boundaries of a state rest exclusively with the authorities of that state.

[2] Two states were notable exceptions, in that they never implemented the EA 2003: the state of Kerala which still has the original vertically integrated Electricity Board, and the state of Tamil Nadu which has a combined generation and distribution company, while the transmission grid has been separated.

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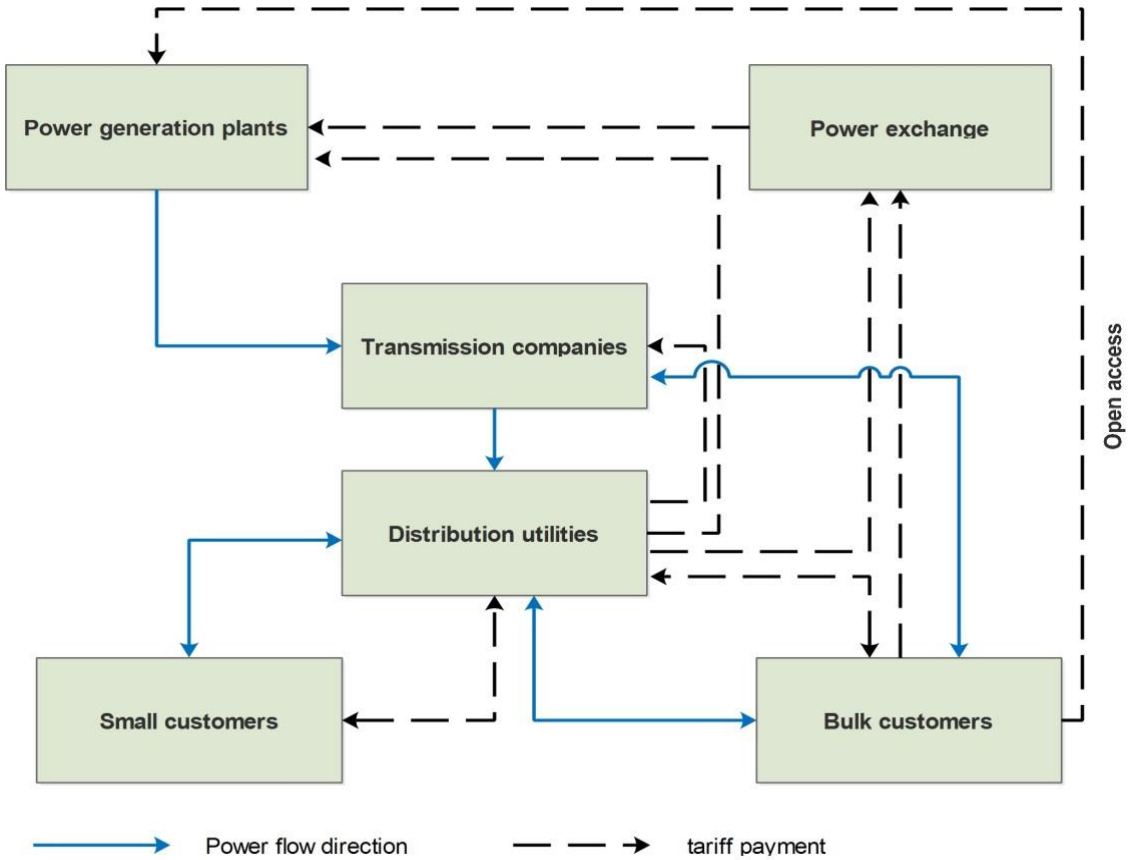
moment fossil fuel power plants (including coal, lignite, natural gas and diesel) constitute more than 60% of the installed capacity.

Figure 1: An overview of electricity market structure in India



Source: Authors

These renewable generation targets, along with the rise of electricity consumption per capita in India, will change the nature of power system issues. On the supply side, the solar revolution will create a huge need to address the challenges of variable and uncertain generation (it is estimated that 94 per cent of new capacity additions in the next 20 years will be VRE (variable renewable energy) under a business-as-usual scenario). On the demand side, the rapid growth in ownership of air conditioning units will change the pattern of load (electricity demand for cooling is expected to increase six-fold by 2040). Indeed, under a BAU scenario (IEA's STEPS), buildings electricity consumption is forecasted to increase from 19 per cent today to about 46 per cent in 2040 (today half of buildings energy consumption is still traditional biomass).

This rapid electrification, coupled with the use of air conditioning and the growth of renewable energy resources, means that the Indian power system will need to provide significant flexibility. Traditionally, coal power plants have been the primary source of flexibility services in India, but given the government decarbonization objectives, their share of the generation mix, and their load factor, are expected to decline. As a result, flexibility needs to be obtained from other resources such as interconnections and DERs. This, however, entails dealing with a great deal of complexity to align both market structure and regulation with new developments in the sector. India does not yet have an established ancillary service market. A functional ancillary service market is a precondition for the emergence of virtual aggregators, or for the evaluation of the spectrum of services that Battery Energy Storage (BES) can provide. Furthermore, despite provision in EA 2003 relating to consumer choice, open access to the distribution

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network remains limited due to a lackof unbundling at the distribution sector level. There are plans for a phased open access todistribution networks for consumers with less than 1 MW load; however, this initiative is likely to face resistance from incumbent distribution utilities if unbundling does not happen prior to that.

Retail electricity tariffs in India are not cost reflective (PwC, 2019). There are substantial cross subsidies among different consumer segments (agricultural and residential consumers are subsidized by commercial and industrial users). This, along with issues such as non-payment of bills, inefficient operation of regulatory assets by distribution companies, delay in receipt of subsidies from the state government for electricity service to some highly subsidized users (such as, lifeline and agricultural consumers), as well as high technical and commercial losses, has seriously eroded the financial position of State Discoms.

The role of State Discoms in the overall electricity sector is critical. It is even more critical for India's energy transition, since discoms are the conduit for delivery of clean energy to millions of customers from centralized, large scale generation facilities. Even the decentralized, customer-owned, grid-connected small rooftop solar, or battery or EV charging facilities all require a healthy discom to "host" the clean energy assets and transact for surplus clean energy generation. Without reforms that fundamentally change the way in which they operate today, the Indian distribution segment could become the 'Achilles' heel' of the overall decarbonization and energy transition efforts (including the electrification of hard-to-abate sectors such as transport, industry, and buildings) and, specifically, deter the development of vibrant DERs markets. DERs are already evolving organically,and if State Discoms continue to perform poorly, there is a risk of further financial underperformance for them, as C&I consumers start to adopt distributed energy technologies. Overall, removing barriers to the growth of decentralization requires major changes in the electricity sector. India has already made some progress on power sector reforms but moving towards a two-sided market in which supply- and demand-side resources, (such as prosumers and DERs), compete on a level playing field will require a new wave of reforms and distribution grid transformation.

The diagram in Figure 2 below illustrates the multiple vectors of change that are transforming the electricity distribution sector as it embarks on the clean energy transition. New policies such as the Renewable Purchase Obligation (RPO), and innovative wholesale tenders seeking Round the Clock (RTC) power from renewable energy developers, are forcing discoms to contend with necessary adjustments to their networks and business processes. They must adapt and invest in order to absorb intermittent renewable power (e.g., investment in forecasting, digitalization, and adapting tariff structures to shift peak demand etc). The resultant distribution business will be fundamentally changed and more consumer-oriented.

Around 40 state-owned discoms participate in an annual ratings survey, that is overseen by the Ministry of Power and its financing arm, the Power Finance Corporation (PFC). In 2019, sixteen discoms succeeded in obtaining an A or A+ rating. However, the Covid crisis and the associated loss of revenue from widespread industrial and commercial shut-downs, has weakened the discom ratings across the board. Only 8 discoms succeeded in earning an A or A+ rating in 2021, as indicated in Figure 3 below. The A+ or A rating also includes financial soundness and profitability, which is important in terms of attracting commercial lending for self-financed investments and network upgrades.

The 2020 pandemic has pushed 50% of the profitable group out of access to commercial finance (as 8 out of 16 discoms have not been able to maintain their high ratings that were achieved in 2019). The diagram below also shows a sharp increase in discoms with C+ and C ratings, along with the reduction in A+ and A rated companies.

This does not bode well for financial recovery without additional support and close monitoring. The new Results Based Distribution Reform Program announced by Ministry of Power in 2021 is expected to provide such support and monitoring. Further details on the new reform program are discussed in Section 2.

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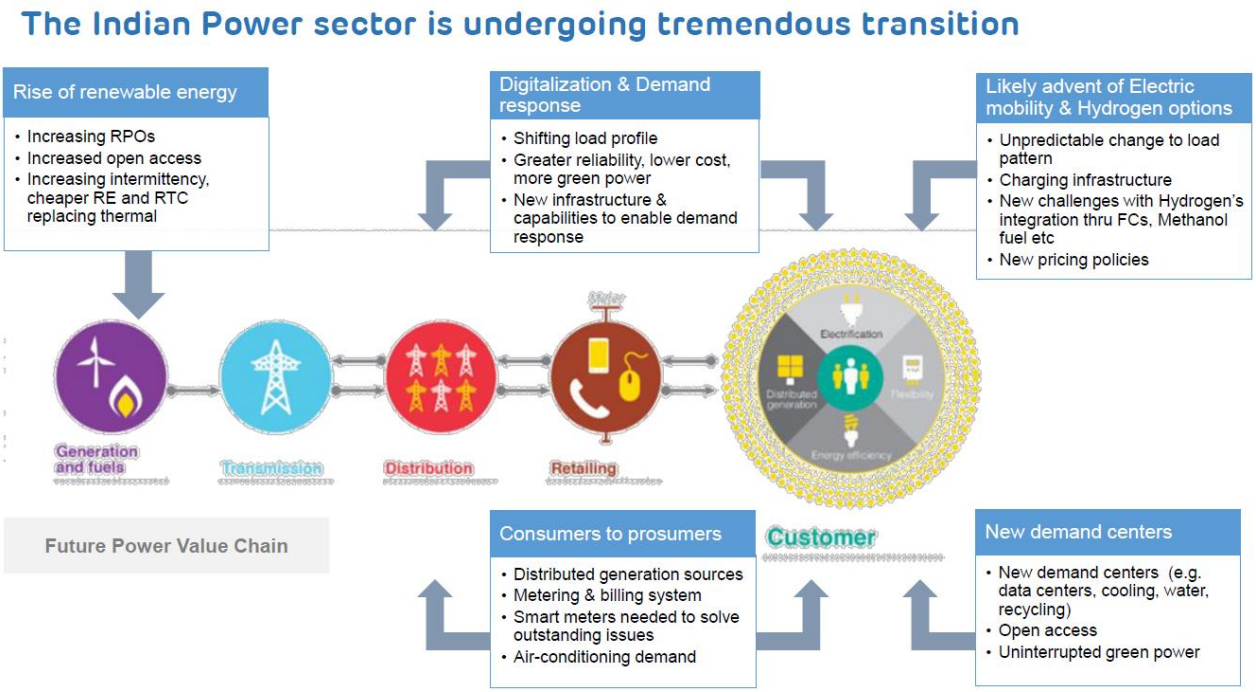
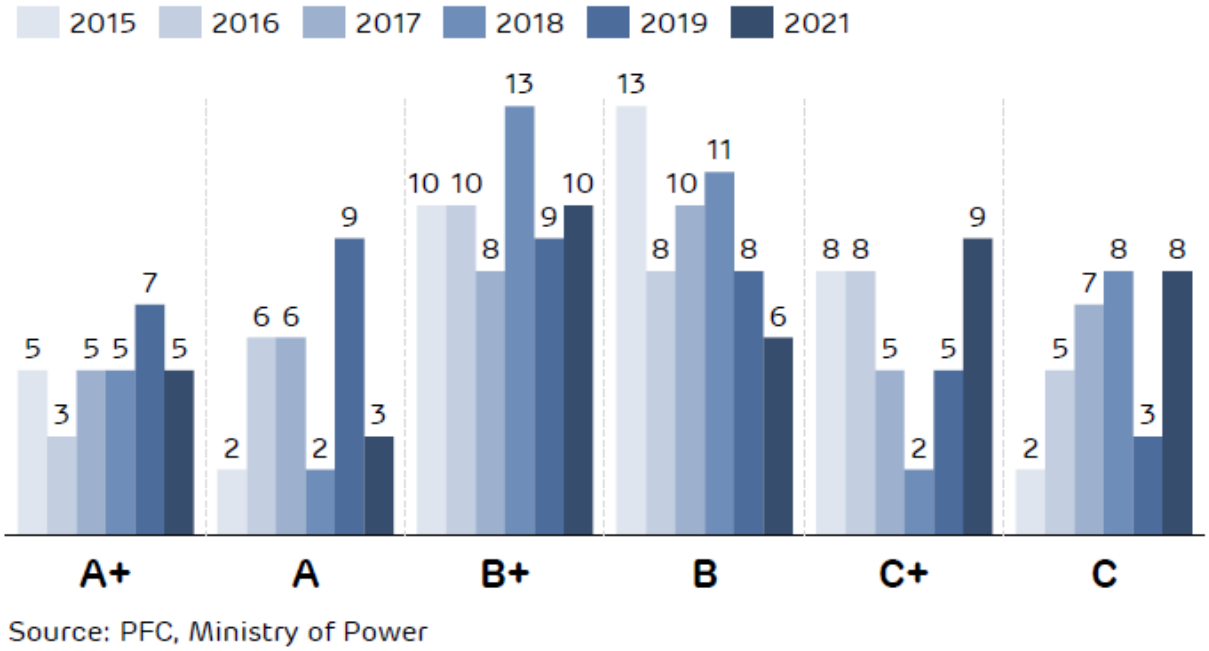
Figure 2: Forces of change in the Indian distribution sector in 2021



Source: Sardana, A. at India Energy Forum Seminar, 08/27/2021

Figure 3: Discom ratings improved in 2019 after four years of UDAY reforms, but then worsened in 2021



Source: Sardana, A. at India Energy Forum Seminar, 08/27/2021

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2. Electricity distribution sector

India's electricity distribution sector consists of distribution companies (Discoms) which are responsible for distribution and retailing of electricity to all consumers including residential, agricultural, commercial, and industrial. It is the most important segment of the electricity supply chain when it comes to the deployment of distributed resources, as well as for the financial health of the entire power sector.

2.1 Retail electricity tariff

From an economic perspective, retail electricity prices are the most important price signal that DERs receive. as they not only define their value for operation and injection to the grid (under schemes such as net metering) but also guide the investment behaviour of end users for the deployment of such facilities (IEA, 2020).

The retail electricity tariff in India has a two-part structure – a fixed component and a variable part (Mishra, 2019). The fixed part covers the Discom's regulator-approved expenses, such as depreciation, return on capital, operation and maintenance, as well as tax liabilities. The variable part, on the other hand, compensates for the cost of purchased power, the cost of transmission and distribution losses, as well as state levies and surcharges. The tariff level is set by the State Electricity Regulatory Commission (SERC) and distribution utilities can apply for a tariff petition with the relevant state regulator.

An important feature of India's retail electricity tariffs is their differential structure, which is basedon the category of consumption (Mishra, 2019). The tariffs for household and agricultural consumptions are lower than those for commercial and industrial uses. On average, firms pay 12 per cent more compared with their actual cost of supply, whereas the agricultural sector pays 55 per cent less (Jain and Nandan, 2020). Agriculture, in some states, is charged a flat tariff with a monthly fee, and is usually unmetered for its water pumping consumption[3] (IEA, 2020). Also, in some states there is not even a flat tariff, and it is totally free. These cross subsidies are introduced to provide affordable electricity to low-income consumers, and also to maintain the political support of agricultural and residential voters. This differential pricing, together with the high fixed cost embedded in long-term legacy PPAs that were introduced to incentivize Independent Power Producers (IPPs), has resulted in the average cost of supply being consistently higher than the average regulated tariff, with serious financial consequences for distribution network utilities.

The inefficient retail electricity tariffs applying to the domestic sector are a major impediment to decentralization and growth of DERs. A below cost grid electricity price signal not only makes investment in DERs uneconomic for households, but also increases the costs of any government subsidies to incentivize deployment of such facilities at the domestic sector. The government is aware of the retail tariff issue, and in August 2018, the Ministry of Power proposed amendments to the 2016 Tariff Policy for electricity,in order to simplify the current tariff categories and rationalize retail tariffs (Mishra, 2019).However, removal of cross subsidies is not straightforward, especially if it involves raising the retailtariff in an environment where there are state and local elections on average every 18–24 months.To make it politically acceptable, to increase the tariff of subsidized consumers (agricultural and residential), such a move is most likely needed to be accompanied with explicit cash subsidies. This, however, has implications for the government budget at the state or the national level, or both. Another constraint on increasing retail tariffs is that it may encourage load or grid defection if thecost of DERs continues to decline and grid electricity remains unreliable (Pargal, and Banerjee, 2014).

[3] Indian Discoms are currently trying to separate out agricultural feeders and install meters for them (IEA, 2020). Also, according to (IEA, 2020), although India's residential electricity tariff is very low in absolute terms, it is among the highest in the world on a purchasing power parity (PPP) basis, being only cheaper than Brazil and Japan. But IEA (2020) acknowledges that the average electricity bill paid by households is declining on a PPP basis.

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2.2 Time-of-use tariff

Time-of-use (ToU) is a retail tariff structure that varies depending on when the electricity withdrawal from the network, or injections to the grid, happens. When consumers respond to time-of-use tariff, it not only saves investment in generation capacity and reserve by shifting consumption to lower price intervals, but it can reduce the need for network capacity enhancement through its effect on peak demand (IEA, 2019). Furthermore, such a pricing method, can significantly reduce the need for curtailment of variable generation such as solar and wind, through coordinating the actions of consumers and producers.

ToU tariff can be either static (the price is determined ex ante) or dynamic (the tariff changes according to the system conditions in real time) (IRENA, 2019). Dynamic ToU is based on wholesale market price movements, while static tariff is usually based on some approximation of the cost ofelectricity supply at different times. Dynamic ToU tariffs are more challenging to implement than static tariffs, because they require continuous exchange of information between suppliers, system operator, market operator, and end users, and rely on advanced metering infrastructure (AMI).

In addition to temporal variation, ToU tariff can also have spatial differentiation based on the presence of congestion in the network (for example: locational marginal pricing, nodal pricing). It can thus send an efficient signal to distributed energy resources, to relieve congestions in the distribution system by shifting dispatch –such that in the upstream of congestion generation decreases or load increases, while in the downstream of congestion generation increases or load decreases.

India has already introduced ToU tariff (which they refer to as time-of-day) albeit only for high- voltage customers in the industrial sector. It is obligatory for energy-intensive consumers in some states and is currently being introduced in the commercial sector as well (IEA, 2020). The profile oftariff varies across states depending on the generation mix and the shape of the load curve. The peak hours in India are usually between 18:00 and 22:00, which can be used to convey the scarcity price signal to all users including smaller consumers. The extension of ToU tariff to smaller users increases the system efficiency, especially as flexible resources such as EVs scale up. Four states have introduced EV-specific time-of-use tariff with a static structure. However, such tariffs also need to include other DERs, together with activities such as batteries and aggregation. Furthermore, for resources such as EVs that essentially are a dynamic load, it is likely that a dynamic ToU tariff will be needed to efficiently accommodate a larger share of EV fleet.

Although time-of-use tariff is an efficient tool to activate demand response and power system flexibility, it is not based on a firm commitment by grid users, so consumer engagement can be a challenge, and thus pre-paid subscription models may be helpful. Challenges arise especially when consumers are unaware of the tariff, or the change in consumption pattern does not provide sufficient economic benefit, or when a dynamic ToU tariff is introduced with the assumption of a manual response by users. Some of these issues can be addressed using automation to enable an automatic response of load to price signal. This, however,requires smart devices (IoT – internet of things) at end users' premises, as well as an advanced distribution grid system with smart meters, a communication network, and a data management platform. India issued a national Smart Grid Vision and Roadmap in August 2013, but to date only a few Discoms (mainly private) have prepared their own smart grid roadmap. Amongst the State Discoms, Bangalore Electricity Supply Company Ltd (BESCOM) was the first to prepare a smart grid roadmap.

2.3 Distribution utilities

In India, distribution utilities are the weakest link, in terms of financial sustainability and operational efficiency, across the whole electricity value chain (Nirula, 2019). This segment faces anumber of critical challenges.

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First, the level of aggregate technical and commercial energy losses (AT&C) is substantial in electricity networks compared with international standards (PwC, 2019). Addressing the issue of energy loss is extremely important, as each percentage point of AT&C loss is estimated to have a financial loss impact of around ₹ 4,000 crore (more than a half billion dollars) for Discoms, on a national-level basis. A range of measures is currently being conducted by the government to lower network losses. These include, among other initiatives, a geographic information system (GIS), universal metering, consumer indexing, feeder and distribution transformer metering, as well as the introduction of distribution franchisees (on a pilot basis from 2012–15) in areas where there are significant energy losses. DERs can also play an important role in reducing distribution network losses if there is an incentive for network operators to promote such resources. This incentive is currently absent, given that the Indian distribution utilities perform both network and retail supply activities.

Second, the retail electricity tariffs are not cost reflective. This, along with high energy losses, insufficient and delayed raising of tariffs, as well as delayed transfer of subsidies from the government in relation to supply of electricity to low-income and agricultural consumers, has led to a financial crisis in many distribution utilities. Between financial years 2014 and 2016, the rate of increase of revenue was 7.42 per cent, whereas the rate of increase in average cost of supply was 8.3 per cent leading to a widening revenue gap (PwC, 2019). Also, between FY 2015 and 2019,the median tariff rise for Discoms at the national level declined from 8 per cent to 1 per cent.

Third, Discoms are locked in legacy long-term PPAs with thermal generation plants that are structured around two-part tariffs: capacity and energy charge. This means that distribution utilities are unable to buy cheaper power when it is available. Furthermore, with the growth of renewable generation, and in the presence of the priority dispatch rule, the load factor of thermalpower plants has been declining. This has increased the financial stress on distribution companiesas they still need to pay the capacity charge (which constitutes around 45–50 per cent of tariff) even though the plant is not dispatched.

The state of financial distress applies to the majority of Discoms in India – apart from a handful of 'legacy' private distribution licensees that serve mainly urban consumers in the largest metro cities (Mumbai, Kolkata) and also Ahmedabad and Gandhinagar (in Gujarat), together with holders of the private licensees in Delhi which resulted from the privatization of a former State Discom in the early 2000s. These private distribution licensees are also subject to tariffs regulated by the state electricity regulator, but do not make financial losses. Private Discoms are not the norm in India as 95 per cent of the country's distribution companies are state-owned.

Recent developments related to the COVID19 pandemic have made it even more difficult for Indian states to continue subsidizing distribution utilities. The Ministry of Power has recently circulated a draft Electricity Amendment Bill that proposes to give every state the freedom to seek out any arrangement it chooses to keep the sector financially viable. This can include privatization, concessioning, leasing, and management contracting, among others. States will realize that if they retain ownership they will need to pay, so it is conceivable that several states will seek to hand the utility over to an experienced investor to operate and modernize.

The present state of financial distress in the state-owned distribution sector, as well as the fact that this sector is still bundled - network and retail functions together - are major impediments to the growth of DER. As distribution utilities rely on energy sales for revenue, their economic interest is misaligned. This is because with every grid-connected rooftop PV approval by Discoms, they are essentially approving a loss of revenue for themselves. Therefore, aligning the interest of distribution utilities with that of distributed resources is crucial to achieving decentralization targets.

To improve the financial health of Discoms, the UDAY (Ujjwal Discom Assurance Yojana) financial aid plan was launched in November 2015. The scheme required state governments to take over 75per cent of distribution companies' debt. The remaining 25 per cent was planned to be recovered through state-backed Discom-issued bonds or debt from financial institutions at an interest rate higher than base rate plus 0.10 per cent (Nirula, 2019). The UDAY scheme, however, did not solve the problem of utilities

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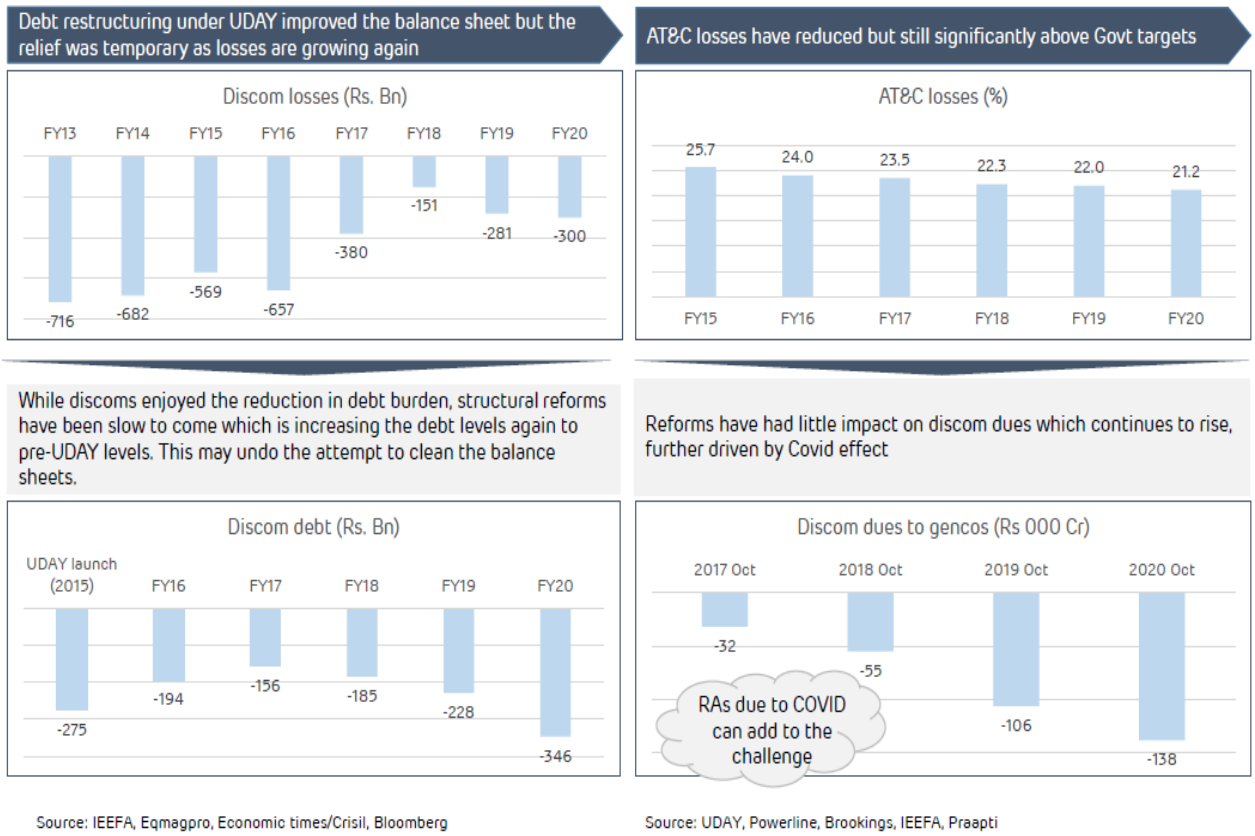
completely, because although the financial component (debt restructuring)was fully implemented, the operational performance improvement component was leftincomplete and un-monitored. As a result, the government has planned to introduce a new financial package in order to help Discoms further, and this time it will be conditional on meeting certain performance criteria.

Figure 4 below illustrates the trends for overall financial losses incurred by distribution companies, and the AT&C losses (when revenues collected do not cover billings and operating costs, particularly payments incurred for bulk power purchase). The Average cost of Supply (ACS) should not be higher than the Average Revenue Received (ARR), because it means that the discom is losing money on the average kWh sold. Debt restructuring under UDAY improved the balance sheet of Disocms but the relief was temporary as losses are growing again and dues to generation companies are piling up. So-called Regulatory Assets (RAs) arise when the discom is not permitted by the regulator to raise tariffs to a level that will fully cover its costs. Tariffs are permitted to rise enough to cover only part of the increased costs, and the remainder is carried forward as RAs. Increasing RAs are always bad for discom cash flows.

Figure 4: Trends for overall financial losses and AT&C losses incurred by Discoms



Source: Sardana, A. at India Energy Forum Seminar, 08/27/2021

The government had also proposed, in the revised Electricity Bill 2018, to separate the electricity supply license from network business (PwC, 2019). This proposal never reached Parliament for discussion and adoption, because states were concerned that it would remove their control over their Discoms (which are used as a political patronage instrument). However, as the experience ofother countries shows such a reform improves the performance of the electricity network and paves the way for the establishment of a retail market to give choice to consumers with respect totheir electricity supply. The separation of supply and network licenses will also benefit distributed energy resources, as they will no

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longer be a direct threat to the business model of Discoms. In theUK, for instance, distribution network operators are incentivized to adopt DERs as an alternative to grid capacity enhancement when it makes sense economically. Retailers can also avoid transmission charges through procurement of DERs.

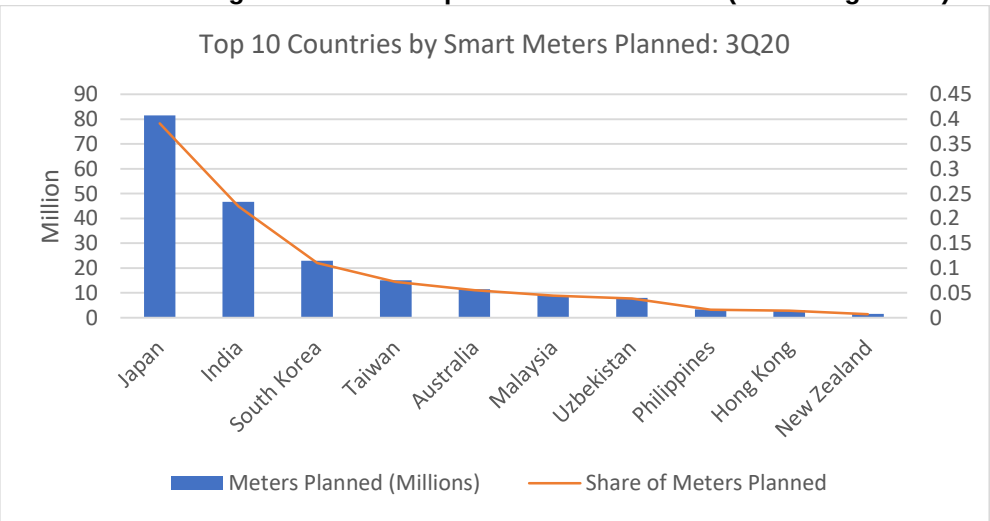
There are also plans to reform Tariff Policy 2016; these include a number of measures such as:

- Simplification and rationalization of retail electricity tariffs,
- Compensating consumers for involuntary load shedding by penalizing Discoms,
- Capping the share of pass-through AT&C losses to end users' tariffs at 15 per cent in orderto incentivize distribution utilities to reduce energy losses.

2.3.1 Technology, grid architecture and DERs coordination

Technology is another much needed area of improvement. Currently, distribution networks in India have not been upgraded in line with the advances that have emerged in the information and communication technology (ICT) industry. There is a need for the development of AMI, data management, and smart grid, as well as advanced business analytics, in order to achieve optimum resource planning. The government recognizes theneed for technological enhancement and has already planned to install smart meters for all consumers by 2022 (PwC, 2019). Indeed, India is among the top ten countries in terms of the number of smart meters planned (Figure 5). Up to August 2019, around half a million meters had been installed in the states of Delhi, Andhra Pradesh, Uttar Pradesh, and Bihar. Smart meters cansignificantly improve the efficiency of customer billing and payment collection and also reduce capital costs and facilitate integration of distributed energy resources.

Figure 5: Countries with highest number of planned smart meters (excluding China)



Source: Guidehouse Insight

The distribution utilities can also utilize blockchain technology to make grid infrastructure more efficient and robust and also to provide new opportunities for interconnectivity and integration ofdistributed resources. This is specifically important as residential solar PV, batteries, and EVs penetrate the power system, because it allows for new decentralized markets in the form of peer-to-peer (P2P) trading, and evolution of the role of distribution companies from network operatorsto platform providers.

There is also the issue of grid architecture. In the traditional Indian grid of the 20th century, therewere relatively few points of power generation or injection, and millions of points of power consumption. With the rapid proliferation of distributed and renewable generation on rooftops and elsewhere, the 21st

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century distribution grid is starting to have numerous points of power injection as well as millions of points of consumption. Devices located on consumers' premises have been incorporated into the set of variables that grid managers must take into account as partof the 'extended grid'. Ambitious plans for Electric Vehicle (EV) roll out will further increase the complexity of the (already overstretched and overloaded) traditional electricity distribution grid.

The traditional Indian state-owned distribution grid will need to build additional layers of automation, communication, and IT systems to enable transformation it into a smarter grid. While old-style grids were made secure only through over-engineering and redundancy (so called 'gold plating', accompanied with a fixed rate of return promised by the regulator on capital expenditure incurred), a smart grid is different. It is cost-effective, nimble, responsive, and better designed for reliability and self-healing operations. Over nearly two decades, the central Ministry of Power has been funding numerous initiatives and schemes to help Discoms with distribution network upgrading and better information management (starting with APDRP in 2002-03, then R-APDRP, RGGVY, DDUGJY). All of these earlier initiatives are thematically linked to investing in upgrading the architecture of the distribution grid, computerizing billing systems, and improving the information and financial performance of the network. They have laid the foundations for a future smart grid.

As distributed energy resources scale up, there is also a need for an effective coordination mechanism between transmission system operator (TSO) and distribution system operator (DSO) in order to avoid harm to the system. The TSO (responsible for balancing the national grid and maintaining the frequency) does not often have visibility over distributed resources, whereas the DSO can utilize them for congestion management. Coordination between the TSO and the DSO on management of DERs can be achieved in a variety of ways. Two very different approaches are the TSO-led model and the DSO-led model (Kristov et al., 2020).

- In the TSO-led approach, the transmission network operator will gain visibility and dispatch control over DERs by integrating DSO circuits into its optimization model under a centralized coordination approach. In this model, the role of DSO would be basically that of maintaining and operating the physical distribution network assets subject to the real time constraints of the transmission system.
- The alternative approach is a DSO-led model in which the distribution system operator (ora third-party aggregator engaged by the DSO) aggregates and dispatches all DERs within their control area such that the transmission operator only sees a single resource at the interface. In this model, the DSO can operate a local market for distributed resources and incorporate the result of that into bids and offers to the TSO. This model requires open access to the distribution network and well-defined coordination codes between the transmission and distribution system operators.
- There is also possibility of a hybrid DSO–TSO model, but it would require a more complex coordination mechanism than previous models.

Since, traditionally, all utility-scale dispatchable resources have been connected to the transmission system, the TSO-led model is compatible with existing arrangements and thus easy toemploy; however, it is more vulnerable to system issues. Given the rise of decentralization and digitalization, it is likely that a DSO-led model better suits the requirements of future complex electricity systems in which distributed resources and bulk power generation co-exist.

2.3.2 The results-based distribution reform package

In 2021, a results-based distribution reform package was introduced. Table 1 contains a summary of the eligibility requirements. It lists the key elements of the customized distribution reform plan that each state must present, in order to apply for funding. It also shows the minimum performance standards and results that must be subsequently met under its reform plan, in order to receive ongoing disbursements

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(hence results-based). These include, for example, maintaining continued compliance with renewable purchase obligations, and also regularly publishing timely financial results in required formats (see items 10 and 11)

States will need to opt-in to the electricity distribution reform program with a plan containing a detailed explanation of how they will address all of these specified reform areas. This is a requirement in order to gain eligibility for central funding which will be released on a results-linked basis. It is important to mention that this is the first time Indian state discoms have had such strings attached, and have had to be accountable for centrally funded "bail outs" or reform-support. UDAY was funded based on the understanding that in return for an upfront cleaning of the discom's balance sheet, and turning the majority of the discom's debt over to the state, the discom would then implement operational reforms to aggressively bring its AT&C losses down to 15% etc. There were no pre-conditions, and no links to results. The present reform package is based on learnings from a series of previous central government-led, taxpayer funded bailouts which have not had the desired results so far.

Funding will again come from the Ministry of Power, with strict oversight and monitoring of results before releasing funds. The two lead implementing agencies overseeing the nationwide performance and progress of the distribution reform program will be Power Finance Corporation and Rural Electrification Corporation (both are central government agencies under the Ministry of Power).

Table 1: Indicative List of Initiatives to be addressed by States in their Discom Reform Plans, as specified in the 2021 Notification on the new "Results-Linked Distribution Reform Package"

1	Putting in place a mechanism to ensure that Government departments promptly pay for electricity consumed
2	Ensure that consumption by subsidized categories is accounted for properly, and associated expenses are paid to the discom in advance by the State treasury (this is mandated by Section 65 of the Electricity Act 2003, but States have been delinquent in compensating discoms for delivering subsidized electricity). Subsidy delivery must be implemented via Direct Benefit Transfer (DBT) to maintain accountability and traceability.
3	Tariffs must be reviewed annually, and must reflect all prudent costs. Any costs that are not reflected in the tariff must be shown separately, and must be funded by either the discom or the State government. No regulatory assets must be created.
4	Discom must prepare and adhere to a roadmap to show how current and accumulated financial losses will be cleared, through retirement of regulatory assets and new funding from the State.
5	Energy accounting is required, through 100% feeder and transformer metering, on the OPEX model (i.e., the cost of these new meters will be repaid in installments by the discom through savings realized from loss reduction, and presumably all meter readings will be done online for transparency and data integrity)
6	Corporate Governance Reforms must be introduced. Part or all of the service territory of the discom will be operated through private participation. Alternatively, state discom operation can be in a joint venture (JV) with Central Public Sector Undertakings (CPSUs), or it can be fully entrusted to CPSUs who will serve as technical partners.
7	Some areas of the discom service territory will have Distribution Franchisee arrangements
8	States must set up electricity police stations in line with the Electricity Act, 2003
9	Training and capacity building of existing discom manpower; creation of an Information Technology/Operational Technology (IT/OT) cadre of qualified staff to manage IT/OT convergence, or alternatively, engaging knowledge partners or consultants to fulfil this function

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10	Compliance with Renewable Purchase Obligation trajectories as specified by each state's regulatory agency.
11	Publication of quarterly audited or unaudited reports in a standardized format circulated by Power Finance Corporation. Quarterly and annual accounts of discoms need to explicitly include details of subsidy payments received, and outstanding dues from state government departments. Annual accounts of the previous year must be published by no later than 30th December of the following year (in years 1 and 2) and by no later than 30th September of the current year (from year 3 onwards)
12	Initiation of performance-linked transfer policy for discom staff (performance pay)
13	Any other activity proposed by the State, which serves to achieve the objectives of the Distribution Sector Reform Scheme.

Source: Adapted from: Sardana A, India Energy Forum presentation on 8/27/202

3. Evolution of distributed energy resources in India

India has undertaken an ambitious decarbonization program and the current trend shows that the country's generation mix is becoming progressively greener. Between 2015 and 2019, the share of hydrocarbon fuels in the power capacity mix has dropped by 7.2 per cent. Over the same period the share of solar power increased from 1.5 per cent to 9.1 per cent, and the share of total renewable energy increased from 13.2 per cent to 23.3 per cent. Use of coal, the dominant fuel ofthe power sector in India, had been showing a tendency to rise in the last decade, but its growth isexpected to slow down due to the increased penetration of low-cost solar and wind power. The role of natural gas in the power sector has declined because of lower-than-expected domestic gasproduction, the high cost of gas imports, the existence of low-cost coal surpluses and last but not the least the growth of highly competitive renewable energy resources.

With the increasing deployment of Distributed energy resources (DERs) and changes in the nature of demand, power sector dynamics are changing in India. DERs improve the efficiency and sustainability of the power sector, but they also help with meeting the country's electricity demand from local sustainable sources ina reliable manner, especially in unelectrified rural population. There are various distributed technologies with different degrees of maturity that are currently being deployed in India. These include solar, wind, small hydro, waste-to-energy, geothermal, tidal power as well as demand response, fuel cell, storage (including EV batteries), and micro- and mini grids. Among these, solar power, batteries, demand response (including energy efficiency), electric vehicles, and micro- andmini grids are solutions that are expected to grow significantly in the coming years due to a range of policy and market-driven incentives.

At the national level, incentives for investments in DERs – including administrative targets and available grant support through Central Financial Assistance – are guided by nation-wide initiatives such as National Solar Mission (NSM), National Energy Storage Mission (NESM), National Smart Grid Mission (NSGM), National Electric Mobility Mission Plan (NEMMP), Faster Adoption of Mobility through Electric Vehicles Phase 2 (FAME-II), India Cooling Action Plan (ICAP), and finally National Mission for Enhanced Energy Efficiency (NMEEE).

This section will review the evolution of solar PV, batteries, electric vehicles (EVs), demandresponse, and mini/micro grids in India. However, due to the idiosyncrasies of power sector planning and policy across the states, we only focus on those aspects that apply to most states andprovide examples from individual states where it is relevant.

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3.1 Solar power

With around 2,300 to 3,200 hours of sunshine per year, depending on the location, the majority of India receives a high level of solar irradiation ranging from 4 to 7 kWh/m^2/day (Hairat and Ghosh 2017). This translates to a potential solar power capacity of around 750 GW in the country.

To realize this enormous potential, India adopted its first major solar energy policy in 2010, under National Solar Mission. This initiative originally had a target of 20 GW by 2022, which later increased to 100 GW in 2015, of which around 40 per cent was planned to come from rooftop PV (Shrimali et al., 2020). In order to lower the weighted average cost of solar power to distribution companies, in the early years of deployment (when the cost was high), solar units were bundled financially with cheap thermal power by a large public sector aggregator. However, this trend is now being reversed as solar power is becoming one of the least expensive generation technologies. Although solar PV has become more competitive than some existing coal plants with lower thermal efficiency, it has a lower system value because its contribution to system adequacy and flexibility is smaller. Combining solar power with battery energy storage increases its system value, but it increases the costs as well. As a result, unless there is decline in the cost of making solar PV energy, replacing existing coal power plants with new solar may not reduce the cost to consumers.

Currently, both central and state governments are involved in the deployment of solar power through various support schemes. Examples of support schemes introduced in India include feed in tariff (FiT), net metering, renewable purchase obligation (RPO), auctions, power purchase agreements (PPAs), renewable energy certificates (RECs) and accelerated depreciation (AD) (Rohankar et al., 2016). These policieshave had a significant impact on the growth of solar power in India, which increased eight-fold from 2.6 GW in 2014 to 22 GW in 2018 – exceeding the original target of 20 GW four years early[4] (MNRE, 2019; Shrimali et al., 2020). However, when compared with the revised national target, the annual capacity addition has been falling short of the yearly target due to a range of institutional, infrastructural, and financing constraints. The central government, however, appears to remain firmly committed to the national target of 100 GW of solar by 2022.

Unlike utility-scale solar, which is the real engine of the Indian solar power market, rooftop solar PV is a subordinate market. Grid connected rooftop solar grew at an estimated CAGR of 83 per centbetween 2014 and 2017, but has subsequently slowed in 2018–19 due to mixed policy signals, resistance from Discoms, uncertainty introduced by tariffs on imported solar equipment, and confusion about the applicability of the new Goods and Services Tax (GST) to solar projects. The capacity of installed rooftop solar in the country at end 2019, is variously estimated at between 2.8 and 5.2 GW. This variation is probably related to different approaches with respect to counting rooftop capacity that has been (i) installed; (ii) awarded but not yet installed; and (iii) is currently under procurement but not yet awarded. Another possible explanation is that MNRE reports the lower figure with reference to mainly residential and public sector rooftop PV projects that have received the central financial subsidy of 40 per cent cost buydown (which is only applicable to smallrooftop projects using domestically manufactured panels), while the higher figure of 5.2 GW includes the unsubsidized Commercial and Industrial (C&I) rooftop projects that have used imported panels.

The adoption of rooftop solar power has happened faster at the level of highly creditworthy commercial and industrial (C&I) customers as developers are more comfortable to offer 'no upfront payment' contracts to these customers, thus speeding up adoption. Public sector consumers and residential consumers lack the same level of creditworthiness as C&I users and therefore hold smaller shares of overall rooftop installations (as of September 2019, the public sector holds 9 per cent while the residential category holds 10 per cent of total installed rooftop capacity in India). Another challenge is that grid electricity consumption is subsidized for residential customers in most Indian states; they are

[4] In 2017, for the first time, solar power outpaced all other sources of power in India.

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thus unlikely to find rooftop PV economically attractive, although that may change in the future if retail tariffs are rationalized and if the cost of PV modules falls further.

In view of the rapid growth in C&I rooftops, and lagging performance in the residential sector, the Ministry of New and Renewable Energy (MNRE) in 2019 announced an innovative set of financial incentives to simultaneously boost the addition of rooftop solar PV to residential roofs and also reduce the customary resistance mounted by discoms regarding grid-connected rooftops.[5]

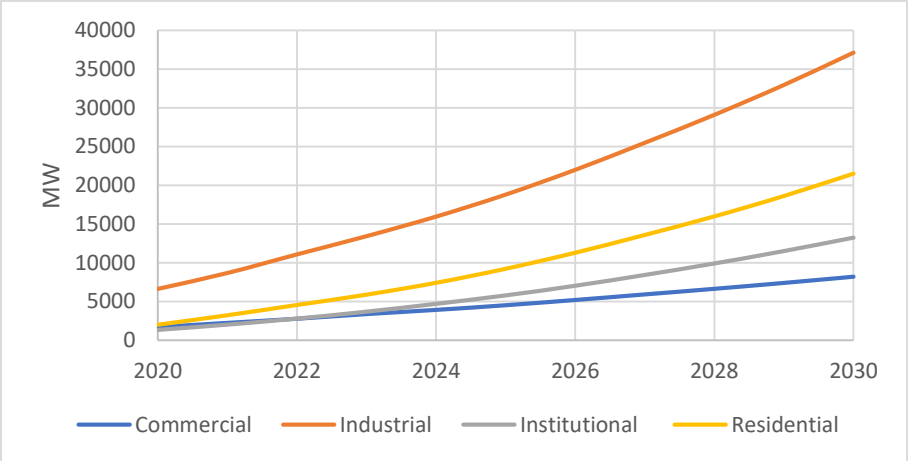
Phase II of the Grid Connected Rooftop Scheme has been designed based on four years of learnings from Phase 1. Phase 2 recognizes the critical role of discoms in any successful grid-connected program, and appreciates the slow progress in Phase 1 because discoms did not cooperate.

Phase 2 therefore is budgeted to financially incentivize discoms play the central role of implementing agency and coordinator for rooftop PV, particularly residential rooftops. Discoms will be compensated for driving the next 18,000MW of rooftop PV installations in the country (the total rooftop target is 40,000MW).

Phase II also redesigns the centrally funded capital subsidy for residential rooftops. The first 3kW attracts a 40% capital subsidy, and additional capacity from 4kW to 10kW attracts a 20% subsidy. While non-residential rooftop PV does not attract any capital subsidy, the discom continues to receive rewards and count all rooftops on its scorecard towards 18,000MW. The impact of this new scheme has been delayed due to the pandemic shortly after its announcement, but since it was designed in consultation with discoms, it is anticipated to deliver results and bring discoms on board, thereby speeding up the overall rooftop PV program.

Forecasts by Guidehouse Insights (2020) show that the industrial sector will remain the biggest growth market segment for adoption of rooftop PV over this decade, although the residential market is expected to overtake commercial and institutional sectors and reach a total installed capacity of around 22 GW by 2030 (Figure 6). IEA (2021), on the other hand, predicts that rooftopsolar in India will reach 80 GW by 2030 and 150 GW by 2040, if enabling conditions are in place. Overall, acceleration of domestic solar PV adoption is possible if the barriers to its growth are addressed. In the presence of these barriers, however, these forecasts might be optimistic.

Figure 6: The forecast growth of rooftop solar PV across different customer categories



Source: Guidehouse Insight

[5] Ministry of New and Renewable Energy policy document on phase 2 of grid connected rooftop photovoltaics (https://mnre.gov.in/img/documents/uploads/7ccd3b4b3bb94a51af516e2ee4fdede3.pdf); February 2019

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3.2 Battery storage

Energy generated by solar and wind is intermittent and highly dependent on season and weather. This has resulted in an increased interest in energy storage, as a flexibility resource, to address variability of renewable generation and provide services to the grid. For example, lithium-ion batteries paired with solar panels are now frequently used by households to maximize their ability to use the electricity generated by solar panels on a day-to-day basis. During the times when solar PV owners need more electricity than the amount their solar panels normally produce, they can use the energy stored in the battery. An aggregator can also bundle the surplus capacity of smaller batteries to offer services such as demand response or frequency response to the transmission grid operator, or flexibility services to distribution network operators. The experience of the UK shows that such an approach results in a faster payback of capital invested for households in comparison with a standard self-consumption model. In a similar way, utility companies are now deploying large-scale batteries to address grid issues such as power quality, reliability, and operational security, as well as enabling them to defer investment in network capacity enhancement.

In the context of India, energy storage technologies are likely to be very important in achieving decarbonization and electrification objectives. Battery storage can shift solar PV output by several hours, from the middle of the day to evening peak demand, in order to better meet demand. Battery Plus solar PV is also a cost-efficient way of providing affordable electricity to isolated communities. Electric vehicles are expected to be the main form of behind-the-meter battery storage in India, but the key challenge is large-scale grid connected energy storage (front-of-the- meter). The GoI estimates that the country will require 27 GW of grid-connected battery storage by 2030. IEA, on the other hand, estimates a deployment of around 35 GW of battery capacity within the same period, under its STEPS scenario. Currently, India is a net importer of battery (and solar PV modules); however, the government established a National Mission on Transformative Mobility and Battery Storage in 2019, with the aim of becoming a competitive battery manufacturer (IEA, 2021).

In recent years, there has been a number of initiatives in India to demonstrate the effectiveness of large-scale batteries in providing various grid services. The first large-scale battery in India was deployed by Tata Power at a substation in New Delhi in March 2019 (Mongabay-India, 2021). This Li-ion project, which has a capacity of around 10 MWh, is being used for peak load management, deviation settlement mechanism management, and other grid services. More recently, Tata Power has deployed the first community-level energy storage system in New Delhi (Smart Energy International, 2021b). This battery supports the distribution network in congestion management and power factor improvement, as well as providing other services such as voltage regulation, frequency regulation, and black start. For the community, it provides back-up power for up to four hours, to support critical infrastructures such as hospitals and commercial complexes, when there is an outage.

Although the IEA forecasts that India will become the world's largest market for batteries over the coming years and decades, as of now, the country has not gone beyond a small number of initiatives. The forecast by Bloomberg NEF shows that deployment of batteries will not kick off until the end of the current decade (see Figure 7). One of the key challenges is that the business model for large-scale batteries is highly uncertain in India. There is no effective market price signal to provide opportunities for arbitrage or stacking revenue. Furthermore, battery storage is not included in the long-term capacity expansion plan of network companies, as there is no incentive for them to consider non-network solutions even when they are cheaper than traditional investment in wires. Network companies can be incentivized, through economic regulation, to contract for the service of providing distributed resources, (including batteries), as an alternative to network capacity expansion (see the UK RIIO model in the Appendix). Moreover, regulation regarding the ownership and operation of large-scale batteries is unclear, specifically as the country moves towards unbundling in the distribution sector. Therefore, significant reforms are needed in the electricity market to enable the uptake of battery storage in the Indian power system.

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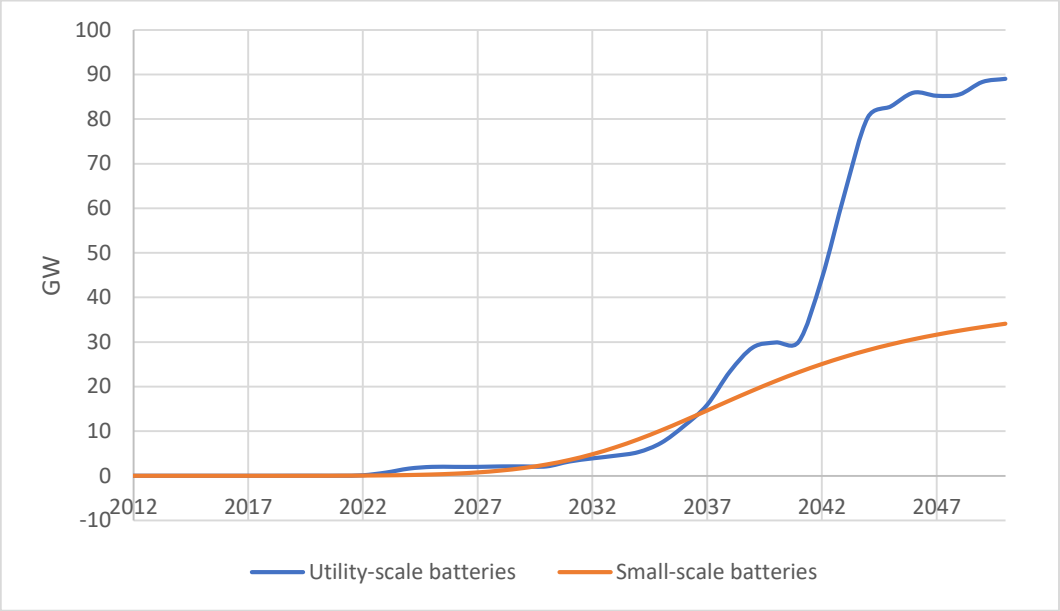
Figure 7: The forecast growth of battery storage in India



Source: Bloomberg NEF

3.3 Electric vehicles

Since the turn of the new century, India has experienced a rapid growth of urbanization and vehicle ownership and usage (Nimesh et al., 2020). In 2013, the GoI launched the National Electric Mobility Mission Plan (NEMMP) 2020, to incentivize adoption of hybrid and electric vehicles to achieve environmental sustainability and fuel security. The target is a yearly sale of 6–7 million of EVs and hybrid vehicles, from 2020 onward. Since then, domestic sales of EVs (excluding exports) have grown at a rate of 1.2 per cent between FY 2015–20 with almost 21.6 million vehicles sold in 2020, of which 80 per cent were two-wheelers and 16 per cent four-wheelers (Catapult Energy Systems,2021)[6].

India has a unique mobility pattern compared with other countries who have adopted an EV policy(NITI Aayog & World Energy Council, 2018). It uses a range of motorized road transport which consists of two-wheelers (79 per cent of the total vehicles), three-wheelers (4 per cent), buses and trucks (3 per cent) and economy and premium four-wheelers (14 per cent). The Indian governmentis pushing for a widespread electrification of the transport sector, and has first targeted the public and shared transportation system. For example, the government is incentivizing cities through financial subsidies to include electric buses in their public transport fleets.

With an outlay of ₹10,000 crore (US$1.4 billion) between FY20–FY22, the government's Faster Adoption and Manufacturing of Hybrid and Electric Vehicles, or 'FAME 2' scheme supports electric two- and three-wheelers as well as e-buses and four-wheelers that have commercial registration. Furthermore, the government levies a low rate of 5 per cent GST on EVs (other rates are 12.5 per cent and 18 per cent), and also offers an exemption on interest paid on loans to assist EV adoption.While the

[6] According to the Society of Manufacturers of Electric Vehicles (SMEV), the Indian domestic EV industry's size stood at 129,600 units in FY19, including 126,000 electric two-wheelers and 3,600 electric four-wheelers. This is an increase from the 54,800 electric two-wheelers and 1,200 electric four-wheelers sold in FY18. The two- wheelers have more than doubled, and the four-wheelers have tripled in the space of 12 months. Meanwhile, the electric three-wheeler segment, which is largely unorganized (and has in the past been dominated by imports from China), is estimated at over 600,000 units in 2018–19.

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presence of incentives for adoption of EVs is necessary, it is not sufficient, as barriers to uptake of these vehicles, such as lack of sufficient charging infrastructure, also need to be addressed.

There are two methods of providing energy to the electric vehicles: battery charging and battery swapping (NITI Aayog & World Energy Council, 2018). Both these approaches are recognised by India as equally useful as each option can address a different segment of vehicles.

Both home charging and battery swapping works well for two-wheelers because they usually use small-sized batteries (1 to 1.5 kWh) that provide a range of about 50 km (WRI India, 2019). As swappable battery is also an economically viable option for three-wheelers which normally use a 3kWh battery. Economy four-wheelers with a battery size of 10–15 kWh and a range of about 100 km can be easily charged at home in about five to seven hours using a 15A AC outlet. If longer distances are required, the battery can be swapped after the initial 100 km. This range is likely to be sufficient for most consumers. However, for premium four-wheelers with a battery size of 30– 75 kWh or higher (range of 200–500 kms), home charging would be difficult as it would take between 10 (for 30 kWh) and 25 (for 75kWh) hours; these cars thus need to be fast charged (WRI India, 2019).

From a distribution grid perspective, EVs with a slower charger can better support the grid through V2G[7] application, as the duration of connection to the grid is higher and they are thus more likely to be utilized for grid stability services. EVs using fast chargers are connected to the grid for a very short period and are thus likely to support the grid only minimally (Ernst & Young, 2019). This means that there are likely to be more system benefits from aggregation of the charging load of two- and three-wheelers and economy four-wheelers.

EVs can also help with integration of solar and wind in India if the EV charging pattern is harmonized with peak hours of solar and wind. This can happen through an appropriate strategy in which the right incentives for EV owners –such as a time-of-use tariffs – and adequate infrastructure for charging are provided. Also, charging batteries with grid-connected rooftop solar PV can significantly reduce distribution network losses and improve grid stability (through lower consumption of electricity from the grid and reduced consumption around or during peak hours). In the absence of a smart charging program to incentivize charging when generation and network capacity are underutilized, distribution networks in India are likely to face constraints. This is because EVs can create demand spikes if a large number of owners begin charging at a specific time (such as early evening at home, or the start of low-cost time windows). Therefore, as EVs scale up, it is crucial that the charging pattern of vehicles be managed in accordance with the real time conditions of the power system (IEA, 2020).

Currently, the total charging capacity in India is very low (less than 100 MW), however, this is expected to change over the next few years. The residential sector is forecasted to be the main destination for the installation of EV chargers, followed by the commercial sector (Figure 8). According to Guidehouse Insight (2020), by 2030, more than 12 GW and more than 6 GW of charging capacity is expected to be deployed at homes and commercial buildings respectively. Unlike the residential and commercial sectors, the shares of industrial and institutional sectors in total installed capacity are expected to be limited.

IEA (2021) forecasts 23 GW of electric mobility in 2030 and 67 GW in 2040 under its Stated Policies Scenario. In this scenario, electrification of final energy consumption will reach 24 per cent by 2040, of which only ~5 per cent is related to the transport sector. In its Sustainable Development Scenario, on the other hand, the IEA estimates that electric mobility will reach 46 GW in 2030 and 168 GW in 2040. It also forecasts that electrification of total final consumption will be about 30 percent by 2040, and electric mobility will represent about 10 of total electricity consumed. This shows that no matter which scenario is realized electric mobility in the next 20 years will represent around 5–10 per cent of total electricity use.

[7] V2G stands for 'vehicle-to-grid'. It is a technology that enables EV owners to inject the energy stored in the battery back to the power grid. In this model, a car battery can be charged and discharged based on a price signal such as a time-of-use tariff.

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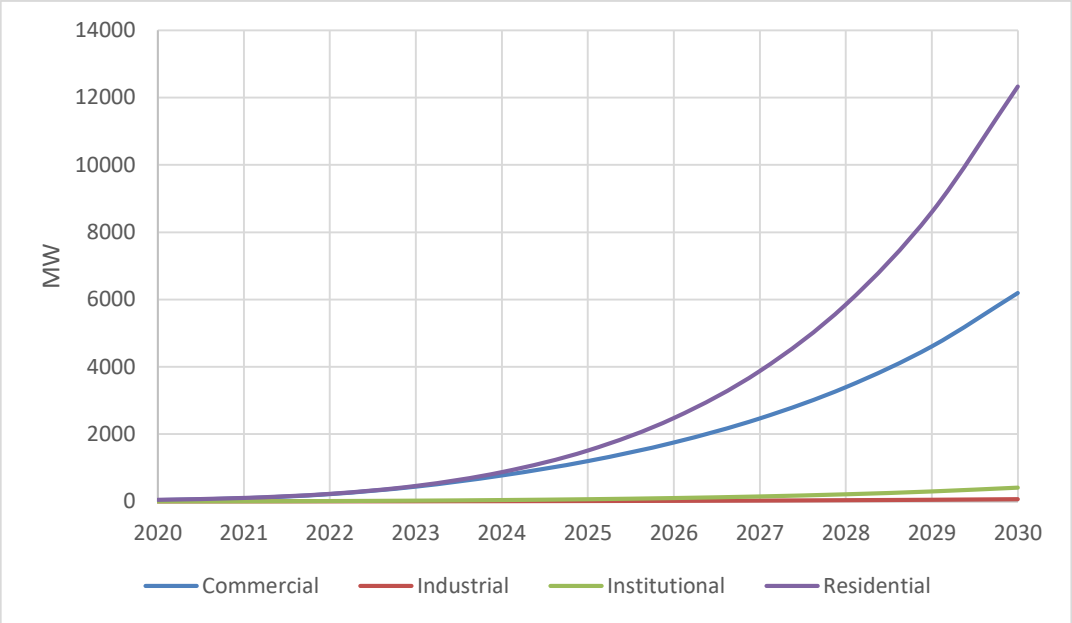
This may not seem impressive compared with national peak capacity (792–997 GW by 2030 and 1552–1835 GW by 2040 according to the IEA) but it is still able to create constraints at the level of low voltage distribution networks. This is because distribution networks are not designed to withstand such a peak, and parts of these networks may already be overloaded. Therefore, smart charging might be necessary to address the challenges that distribution utilities face in relation to the EV load.

Figure 8: The forecast growth of EV charging capacity in the country over the next 10 years



Source: Guidehouse Insight

3.4 Demand response

Although demand response as a resource is new in the Indian electricity market, the country has previous experience with demand-side management (IEA, 2020). This stems from the fact that India has traditionally suffered from generation capacity shortage which caused distribution utilities to frequently use demand shedding to balance the local grid. As a result, electricity demand in India has been historically responsive to reliability of supply and many consumers are used to actively managing their demand through private investment in backup equipment such as diesel generators. With the decline in the cost of DERs such as solar PV and batteries, these emerging technologies are expected to replace costly diesel generators. Although this is not a typical demandresponse, these initiatives can increase the likelihood of success of future demand response programs, when there are appropriate tariff and regulatory measures in place.

The presence of an adequate tariff structure and incentives is crucial to promote demand response and to incentivize distribution networks to see flexible demand as a resource rather than a threat to their business. One of the key features of demand response is that it can mitigate, to some extent, distribution utilities' financial burden by reducing the per-unit cost of electricity, especially if the subsidized sectors are incentivized to provide it (Hale et al., 2018). Currently, distribution utilities in some states impose load shedding on consumers without compensation, to avoid the financial losses associated with additional units of electricity supply – a strategy which can be exacerbated if a (or the) Deviation Settlement Mechanism (DSM) does not efficiently penalize withdrawal of service (Rudnick and Velasquez, 2018).

Demand response (DR) is still in its nascent stages in India. However, the rapid growth of energy consumption, non-remunerated grid supply disruptions, and penetration of renewables could accelerate

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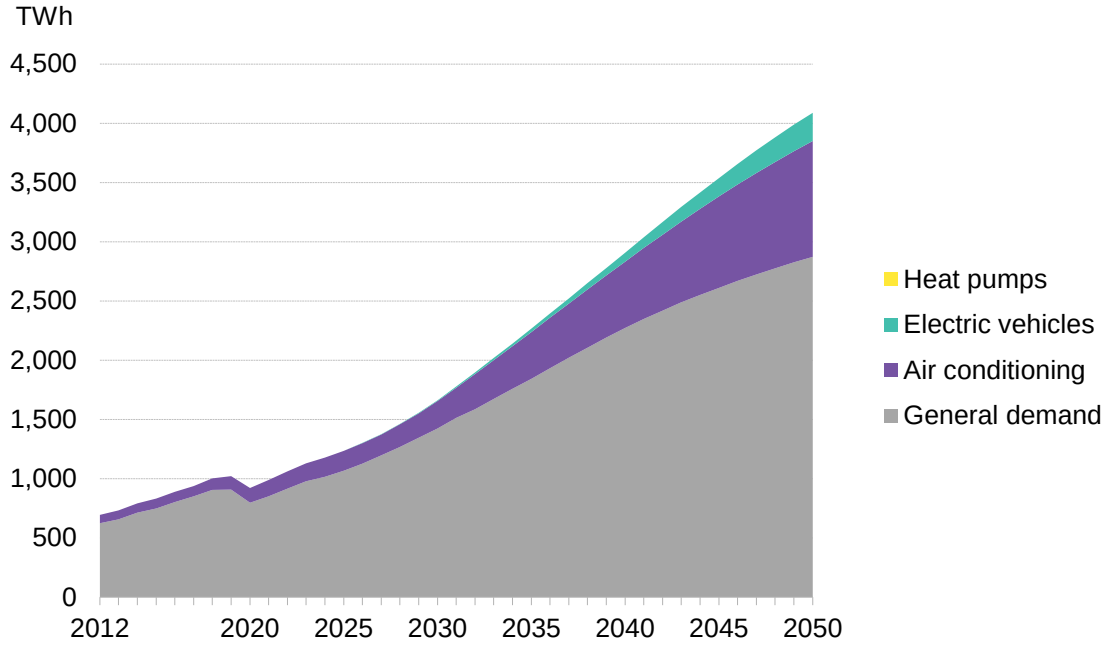
demand response programmes in the country. IEA (2021) forecasts that the share of electricity demand represented by total energy demand in buildings will increase from the current 20 per cent to about 50 per cent in 2040. Furthermore, the average hourly variation in electricity demand will also increase significantly. The main driver of the increased variability of demand is a surge in the adoption of cooling systems over the coming years and decades (Figure 9). It is estimated that the difference between the lowest and highest air conditioning load during the day will increase from the current 40 GW to more than 200 GW by 2040. Overall, there are potentially four sources of demand response based on DERs in India: (i) agricultural pumping,[8] (ii) cooling loads, (iii) battery energy storage, and (iv) EV charging (IEA, 2021). These all provide ample opportunities for demand response in the country.

Figure 9: Electricity demand by source



Source: Bloomberg NEF

Over the last ten years some pilot demand response initiatives have taken place, with a focus on large C&I customers. Table 2 presents a summary of a few examples of such programs. The projectin New Dehli involved 144 consumers with about 25 MW total coincident peak demand and it was subject to total of 17 events. According to Hale et al. (2018), the 75th percentile of responses ranged between 3 per cent (educational buildings) to 62 per cent (pumping facilities), with an overall 75th percentile of responses equal to 10 per cent of total load. It is estimated that a mass roll out of such projects across C&I consumers could reduce national peak load by about 5 per cent (ibid).

[8] In the agricultural sector, direct load control and interruptible pumping programmes are likely to be effective given the fact that agriculture feeders are being separated in many parts of India. Night-time watering is typically employed during DR event days. Utility or DR providers could curtail irrigation equipment using automatic switches or rely on manual action by the farmers, but evidence shows that automation is more effective.

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Table 2: Examples of demand response pilot programs in India

State	Mumbai	New Delhi
Utility company	Tata Power Mumbai	Tata Power Delhi Distribution Limited
Demand response provider	Customized Energy Solutions	Honeywell
Target consumers	C&I with over 500 kW capacity	C&I with over 300 kW capacity
Program type	Interruptible load services, energy shifting programs (incentivized)	Interruptible load services
Key features	Interruptible load based on lowering air-conditioning load, energy consumption shifting from process-heating applications using thermal storage	Automated demand response (ADR) along with AMI to communicate and dispatch curtailment requests.
Potential for peak load reduction	18 MW (2014)	12 MW (2016)

Source: adapted from Hale et al. (2018)

A mass role of demand response however entails addressing several challenges. Currently, there isno explicit incentive framework to promote demand response across all consumers in the country.

The structure of final tariffs is such that there is no obvious benefit for small consumers to change their consumption behavior, as they are primarily on an inclined block tariff. There is very little use of dynamic pricing and time-of-day tariffs are only offered to some C&I consumers. Furthermore, distribution utilities might also have little incentive to procure demand response from C&I consumers because of concerns about revenue loss, given the higher tariff that this consumer category pays. In addition, the role of aggregator and its scope of operation have not yet been defined in India's power sector regulation. The presence of aggregators is important to enable demand response, especially from smaller consumers whose direct participation in the market is inhibited by transaction costs. Furthermore, ICT infrastructure does not yet have full coverage in India at the level of small consumers.

India could provide an example of large-scale adoption of demand-side response from all aforementioned DERs but given the existing market and infrastructure barriers, it is expected that only large industrial consumers will be able to realize this resource in the next 10 years (Figure 10).

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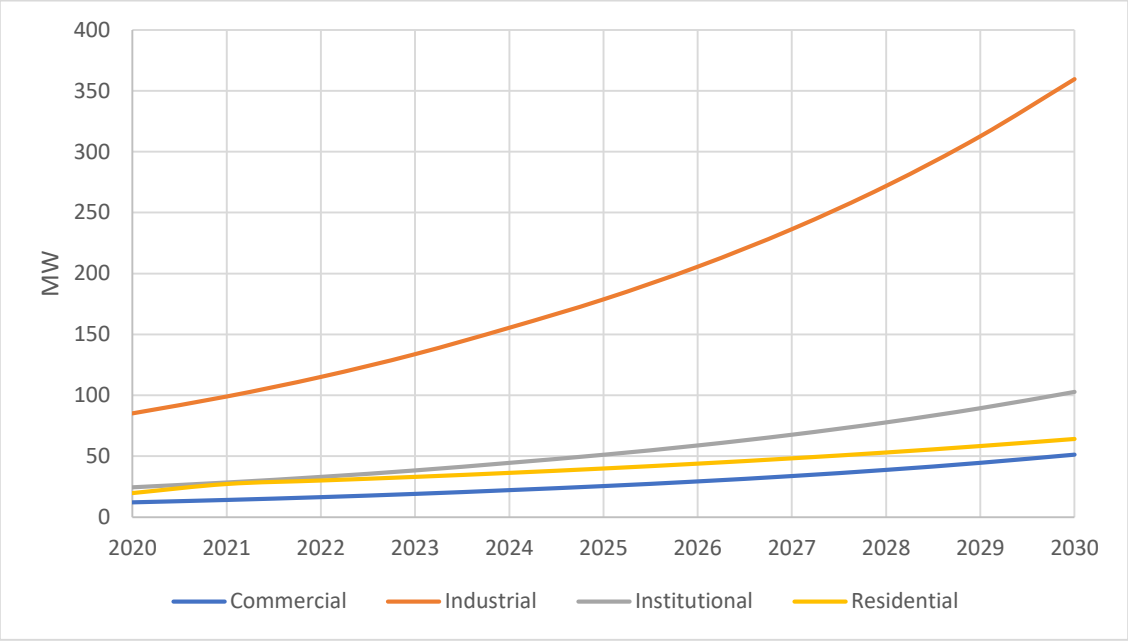
Figure 10: The forecast growth of demand response across different customer categories



Source: Guidehouse Insight

3.5 Microgrids and minigrids

Microgrid is a decentralized group of (usually) renewable energy sources and load; it typically encompasses energy storage and associated load control equipment that works in tandem with the main grid, but it can also function independently in an 'island mode'. Minigrid is similar to a microgrid except that it operates with a larger generation capacity.

Due to features such as reliability, flexibility, and availability, microgrids are often considered as an effective solution for remote rural electrification, or even for urban areas where the electricity grid exists but the service quality is poor. Indeed, the experience of India shows that microgrid has been more frequently deployed as a response to inadequate grid supply quality, rather than unavailability of the grid (Satsangi et al., 2019).

India has explored different technologies for microgrid, and it seems that solar PV has emerged as the preferred option (Bhattacharyya et al., 2019). This is also the case in places where it is deployed as a minigrid to provide electricity access. The state of Chhattisgarh has so far deployed the largest number of solar mini grids (with total capacity of 3.5 MW); these provide electricity to 57,000 households in 1,439 villages (Joshi and Yenneti 2020). Apart from solar PV, small hydro-based minigrids are the most commonly adopted model.

Microgrid provides an opportunity for India to narrow the current gap between largescale solar PV and rooftop solar PV deployment, as the technology is more in line with the requirements of the domestic market than those of C&I consumers (Satsangi et al., 2019). However, there are three primary challenges that might inhibit the efficient growth of microgrids in India.

First, these projects are of various sizes, ranging from a few kW to MW, and the per unit cost of electricity increases as the project becomes smaller. This means that a market-based penetration of microgrid based on negotiated tariffs needs to rely on a higher willingness to pay for reliability by end users. Although a mutually agreed tariff is envisioned under EA 2003, this is unlikely to encourage the growth of microgrid without regulatory intervention (Bhattacharyya et al., 2019). In India, rooftop solar is incentivized through net metering, but there is no financial assistance for grid-connected solar PV

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microgrid systems. Therefore, there might be a need for government support to enable the growth of these technologies.

The second issue is that in places where the grid does not exist, there is higher economic risk for developers of microgrid systems. This is because India's default strategy for electrification is grid extension; hence if the network development plan increases the likelihood of stranded microgrid/minigrid assets, it will affect the risk appetite of project developers.

The third challenge is that distribution utilities consider microgrid/minigrid projects, as their competitors as they can potentially create higher efficiencies in executing many of the distribution utilities' activities. This higher efficiency is likely to be related to the private sector nature of micro/minigrid facilities and their use of modern technology, and also to the experience that minigrid operators have gained in efficiently conducting various functions such as generation, distribution, and customer management (Shrimali, and Sen, 2020). This means that the success of microgrid initiatives is contingent upon a creating a framework that aligns the interests of both parties, such that distribution utilities see microgrids as their partners rather than as their competitors.

3.6 Assessment of growth potential of DERs in India

The government of India has made progress in several areas which are important for the growth of DERs. The Energy Efficiency Services Limited (EESL), a joint venture of public sector units under the Ministry of Power, has a plan to install 250 million smart meters across India under the Smart Meter National Programme (SMNP). Up to 2020, EESL had successfully installed one million meters under SMNP. Such an initiative improves the reliability of electricity supply by enabling distribution utilities to identify and automatically respond to electricity demand, which means fewer power cuts and thus lower costs to consumers. EESL has also introduced an innovative benefit sharing service model under the Domestic Efficient Lighting Program (DELP) that requires no upfront payment by distribution utilities. Under this program, EESL provides LEDs bulbs to consumers at a rate of ₹ 10 each (market price of ₹ 350–600), the costs of which are recovered from energy savings achieved by Discoms over a five-year period (CEA, 2018).

To improve renewable energy integration, the Indian government has also established 11 Renewable Energy Management Centres (REMCs) around the country as a central scheme, and has mandated PowerGrid, a Maharatna CPSE (Central Public Sector Undertaking) under the Ministry of Power, as the implementing agency (ETEnergyworld.com, 2021). The REMCs are co-located with the SLDCs (state load dispatch centres), RLDCs (regional load dispatch centres), and the NLDC (National Load Dispatch Centre.[9] The REMCs are equipped with highly advanced renewable energy forecasting and scheduling tools which can provide increased controllability for the grid operators.

Under favourable market and regulatory conditions, DER resources will grow in India and provide several opportunities for the power system and country's energy sector. The IEA predicts rooftop solar PV, battery storage, electric mobility, and demand response are going to rise significantly over the coming decades under its various scenarios (Table 3). Bloomberg NEF also predicts that solar PV and batteries are likely to have a noticeable share in the Indian power sector's installed capacity (see Figure 11). Indeed, Bloomberg anticipates that the share of decentralized capacity in total installed capacity in India could reach around 25 per cent by 2050. This massive shift of value downstream provides several opportunities for the power system and the country's energy sector in general.

[9] SLDCs at which REMCs are located are: Tamil Nadu, Karnataka, Andhra Pradesh, Maharashtra, Madhya Pradesh, Gujarat, and Rajasthan. RLDCs at which REMCs are located are: Bengaluru, Mumbai, and New Delhi.

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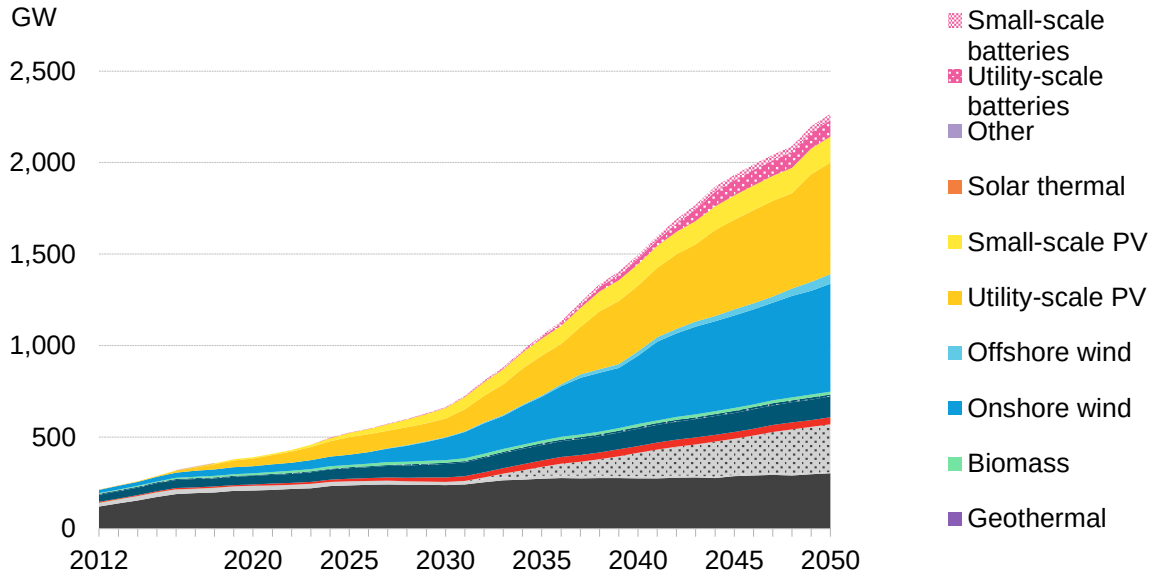
Table 3: A summary for forecasts for the growth of DERs in the Indian power system

Technology	2019	2030	2040
Rooftop Solar	Less than 10 GW	80 GW	150 GW
Battery Energy Storage	0.00075	35 GW	200 GW
Electric Mobility		23-46 GW	67-168
Demand Response	0.168 GW in 2021 (1)	0.578 GW (1)	
Microgrid		15 GW	

Source: IEA (2021), except (1) whose source is Guidehouse Insights (2021)

Figure 11: Cumulative installed capacity of various resources in India



Source: Bloomberg NEF

First, growth of the decentralization paradigm can improve security of energy supply and lower the costs of having a reliable power system. Large-scale conventional thermal plants are still the dominant source of power generation in most countries around the world, including India. Integration of DERs not only improves resource diversity but also reduces the cost of power system reliability via replacing costly thermal power plants and curbing the national electricity demand peak.

Second, DERs can decrease the costs of balancing and ancillary services by increasing the competition for these services. In most countries around the world, such services are provided by large thermal generation as part of the grid connection requirement, but the importance of having a market for them in which all resources, including DERs, can participate is becoming increasingly recognized.[10]

[10] The Indian Central Electricity Regulatory Authority issued a 2015 Draft Policy on Ancillary Services Markets, (http://www.cercind.gov.in/2015/draft_reg/Ancillary_Services.pdf) but this policy does not include a role for private providers of ancillary services (see Section III, Proposed Framework).

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Third, DERs can decrease the cost of network investment as these resources, in some cases, are a cost-efficient alternative to grid capacity enhancement. In countries such as the UK, the regulatory framework incentivizes network companies to contract distributed resources when this is more efficient than traditional network investment (see RIIO model description in the appendix).

Fourth, deployment of DERs can reduce CO2 emission as well as local air pollution, by reducing the need for inefficient coal and gas power plants to run for longer hours during the year. And last but not least, a market which utilizes both supply-side and demand-side resources can reduce end users' bills.

However, there is no opportunity without cost. The Indian electricity system requires significant reforms to remove barriers to the growth of these resources. These barriers are found in areas such as: retail tariffs, market design, distribution sector unbundling, and in addressing the financial crisis affecting State Discoms. These measures could pave the way towards a two-sided market in which both supply- and demand-side resources can participate on a level playing field.

4. Emerging business models

A major challenge of facing DERs is to develop business and financing models that stimulate their rapid growth, especially in the residential sector (IRENA, 2017). Currently, the market for decentralized resources in India is characterized by various subsidies and practices, with weak implementation and often the absence of oversight. For instance, development of rooftop solar PVin India's domestic market faces several barriers including the absence of risk mitigation instruments for low-credit consumers, the disaggregated nature of the market, and a distorted gridelectricity price signal.

In India, rooftop solar PV is a derivative of utility-scale solar, which is the real engine of the solar power market in the country. Rooftop solar developers find the commercial and industrial sector (C&I) to be the most attractive customer segment, even though incentivizing its customers entails offering a solar tariff that is slightly less than the grid tariff. Likewise, the C&I segment is the most motivated consumer group for investment in rooftop solar because they can avoid high Discom tariffs which include a cross-subsidy surcharge. Another important consideration is that C&I customers are the most creditworthy customer segment, so they can benefit from business models that do not include upfront payment. This is where residential customers rarely qualify as being sufficiently creditworthy, thus the 'no-money-down business model' has become skewed towards C&I.

Currently, there are three business models in the Indian rooftop solar market: Capex model, Opex model and rooftop rental model. In the Capex model, the customer pays in full upfront for the rooftop system. The customer can then use the facility for self-consumption and thus decrease his bills from the Discom. Alternatively,the customer can opt to use the solar PV for the sole purpose of selling energy to the grid, in which case he will be compensated at a fixed feed-in tariff as measured by a uni-directional gross meter.In this case, the investor has to pay the retail tariff for his own consumption. The feed-in tariff andthe retail supply tariff are typically different rates, with the former being lower than the latter. When this is the case, it makes more economic sense for the owner to use solar PV for self-consumption if there is a demand.

The Opex model is a more complex approach. In this model, the developer pays for the hardware and installs it on the customer's roof and then sells metered rooftop energy to the customer at an agreed unitrate which is less than the Discom tariff. The customer consumes what he can, pays the developer for it, and exports the surplus to the grid –for which he receives credit from the Discom on his electricity bill for the exported quantity. In states which are still offering net metering, the value of credit per unit exported to the Discom is given at the customer's Discom tariff (which is higher than his rooftop tariff). In the next billing period, the customer pays only for the net number of units consumed from the Discom – in other words, for units purchased minus units exported to the grid previously. In this way, the customer can substantially reduce his grid consumed electricity bill.

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The Opex model can also be arranged in the form of 'solar as a service' (SAAS) which has three variants. In one, the developer obtains commercial financing for the rooftop system and holds it on his balance sheet while it is installed on the customer's premises. The developer repays his loanout of the regular payments received from energy sales to his clients.

Another variant of SAAS is the Build-Own-Operate-Transfer (BOOT) model. The developer owns the asset for an agreed period and sells the metered electricity to the client from the client's own rooftop. The monthly fee paid by the client includes a small, fixed component for the hardware. At the end of the agreed period, the developer transfers ownership of the system fully to the client.

A third variant of SAAS is the leasing model. Here the client pays a monthly flat rate to the developer, who is the owner of the rooftop PV system that is installed on the client's roof. The contract may be for an agreed number of years. There is no metered energy sale, thus the energyproduction risk is entirely with the customer. The leasing model is the simplest method administratively, but it currently attracts a high rate of Goods and Services Tax (GST) (18 per cent) and is therefore rarely used in India at this time.

In the rooftop rental model, energy is generated from rooftop solar panels both by and for the Discom. The rooftop owner does not consume any of the electricity generated by PV – rather the Discom uses the available space on his roof to place its panels and generate electricity for itself. This electricity is fed into the grid with the advantage of having no transmission and distribution (T&D) losses. The rooftop owner takes zero operating risk and is unaffected by the amount of generation taking place. He receives a flat rental payment from the Discom for the use of his space.This model is used extensively in urban areas of Gujarat.

Similar to the types of SAAS model discussed above, many other service-oriented business models for DER are emerging across the world – such as 'storage as a service' or 'cooling as a service' (CaaS) – but these are still not present in India. CaaS is specifically very relevant in the context of India, given the expected rise of demand for cooling in the coming years. It is a pay-for-service model which does not require any upfront investment by the customer. A service provider installs the technology and charges the consumer on a "per unit of cooling" basis. This creates an incentive forthe provider to install the most efficient technology and for the user to consume energy efficiently.This model is arguably cheaper for customers and more profitable for technology providers due to reduction in energy consumption and better investment in preventive maintenance.

4.1 Net metering

Net metering is a scheme in which the Discom buys back unused surplus energy from solar PV, usually in the form of credit to be offset against the consumer bill in the next billing period, (the buyback price is the same as the retail electricity price). This contrasts with gross metering, in which the surplus energy is purchased by the Discom at a rate lower than the retail tariff. In India, the net metering scheme was introduced in 28 states (IEA, 2020) and unused energy was bought by the Discom at the same price as the tariff charged to the customer. However, the way which surplus credit is treated is different across distribution utilities. Some Discoms have a one-month limit in their net metering plans – in other words, the surplus generation must be used within the following month or it will be 'lost' from the accounts. Other Discoms have a twelve-month period for offsetting the surplus generation credits. In general, a number of States have now discontinued the net metering incentive as described here, due to a negative revenue impact for cash strapped Discoms.

The net metering policy has clearly not been equally effective in all states as there is a concentration of 61 per cent of rooftop PV capacity in just six states (Maharashtra, Rajasthan, Tamil Nadu, Gujarat, Karnataka, and Uttar Pradesh). Maharashtra was the leading state in terms of the share of total installed capacity (17 per cent as of March 2019); this is linked to the fact that Maharashtra's consumers pay the highest electricity tariffs.

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Although net metering creates significant incentive for investment in rooftop solar PV, it is an inefficient and inequitable model. It is inefficient model because it does not address the question of optimal system integration of DERs. Indeed, with net metering, solar PV deployment may happen in places where the system faces constraints. Furthermore, when retail prices are mainly volumetric and energy injected to the grid is priced the same as the retail tariff, solar PV owner can avoid paying the network fixed costs, either totally or partially, which in turn results in these costs being recovered from a smaller pool of consumers. This places a higher burden on those consumers who cannot afford to own a rooftop solar PV and hence raises the issue of equity.

Discoms are also not in favour of net metering, since it makes their cash flows constrained and unpredictable. Discoms instead prefer gross metering because the price they pay to the rooftop system owner is closer to the Average Power Purchase Cost (APPC) which they pay for the rest of their bulk power purchases. Yet for consumers who have invested in rooftop PV based on a net metering policy, it is extremely unattractive to be compensated only at a low feed-in tariff (equal to the APPC) for their surplus energy. This may paradoxically make the investment in a battery more attractive, because discharging saved electricity from the battery permits avoided cost at the retail tariff.

Since early 2020, several states have announced attempts by the respective Discoms to roll back net metering benefits.[11] The petition to withdraw net metering has been implemented insome states and is still under regulatory review in others. Based on the initial petition put forward by the Discom, the proposal is the subject of public hearings and public comment. The direction is clear, however: State Discoms are fighting with rooftop PV, claiming that they cannot afford it. There have been mixed policy signals on net metering in many states in the past two years, with discoms strongly in favor of removing it entirely. However, there has been a consumer backlash and strong representations to the regulators by both the rooftop installation industry and consumers in all categories. Most recently, the central government has reinstated net metering for rooftop PV installations up to 500kW in capacity.

4.2 Peer-to-peer energy trading

In the established business models discussed in the previous section, prosumers buy electricity from the grid at the retail price and sell their surplus to the distribution utilities either at the samerate as the retail tariff (net metering) or at a rate lower than the retail tariff (gross metering). Boththese business models have issues. Net metering places a financial burden on the distribution companies while gross metering may not create sufficient incentive for consumers, as they sell their electricity to the grid at a lower price than that as which they buy from the grid.

These issues can potentially be addressed in a peer-to-peer (P2P) trading business model. P2P electricity trading is a platform-based marketplace where consumers and producers can directly trade electricity without the need for an intermediary (IRENA, 2020). A P2P business model can beestablished in small communities such a neighbourhood or at a large scale such as a city. There is no limit to participation in both sides of the market, as prosumers can switch their roles between buyers and sellers. When platform subscribers are users of the distribution system, the platform provider can be the distribution network operator, or an independent entity that closely interacts with the network operator. Alternatively, P2P can be organized among the users of an isolated mini-grid which is independent from

[11] Maharashtra's state-owned Discom has announced plans to introduce a steep grid support charge (GSC) for those who invest in rooftop PV, after a total installed capacity of 2000 MW of rooftop PV is reached in the state. Such a charge will make rooftop solar much more expensive per unit than Discom power and will deter investment. Karnataka has said that it will stop net metering from 31 March, 2020 and will only permit gross metering. Uttar Pradesh has already withdrawn net metering for C&I consumers, claiming that they do not require this support, and that the Discom will pay them a low flat rate for any excess power injected to the grid. Tamil Nadu also no longer offers net metering to C&I customers. Rajasthan has no payment for net energy credit except for a limited amount to domestic consumers. In view of the recently issued Electricity (Rights of Consumers) Amendment Rules 2021, to permit net metering for installations up to 500kW in size, all state regulators are re-examining the recent policy reversals on net metering that they have issued. Given the concurrent nature of the electricity sector in India, no state regulator is under an obligation to follow the central directive on net metering, however.

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the main distribution system. The business model of the platform can be subscription-based, transaction-based, or a combination of both.

India, to date, has rolled out a few pilot P2P electricity trading projects. In 2019, BSES Rajdhani Power Limited (BRPL) partnered with Power Ledger, to conduct a large- scale P2P energy trading pilot in Delhi. This project, which was the first trial of its kind, initially included around 5– 6 MW of existing solar PV, servicing a group of communities in the Dwarka region (Power Engineering International, 2021). During the pilot project, prosumers were able to monetize their excess solar energy by selling it to their neighbours rather than the grid. This enabled participants who did not have their own rooftop PV systems, to access clean low-cost energy, while providing the distribution utility with an alternative resource for grid balancing duringpeak demand.

The second trial was launched in Uttar Pradesh state by the India Smart Grid Forum (ISGF) in collaboration with Power Ledger (Smart Energy International, 2021). This trial included 12 participants, of which nine had rooftop solar PV and three were just net buyers. This pilot aimed to show the feasibility of rooftop solar energy trading between prosumers through smart contracts on the blockchain platform. The trial outcome was expected to help both the regulator and the state utility to design regulation for P2P trading. According to Smart Energy International (2021), Uttar Pradesh Electricity Regulatory Commission was the first regulatory body to approve a P2P trading pilot as part of its solar rooftop policy.

The most recent P2P pilot project is a joint venture between Tata Power and the Government of the NCT of Delhi in partnership with Power Ledger (Power Ledger, 2021). The project, which includes over 2 MW of solar PV aims to facilitate P2P trading between multiple consumers in NorthDelhi. Participants with solar generation will be selling their excess energy to other residential andcommercial sites, who can choose which seller to buy from, with Power Ledger's blockchain audits keeping track of energy transactions. The trial is expected to pave the way for the establishmentof an integrated system of DERs including solar PV, EV charging stations, and battery storage.

Overall, P2P has the potential to become an integral part of future electricity markets. As power sector moves towards a prosumer economy operating via the Internet of Things (IoT), P2P market arrangements will likely grow as they provide an alternative route to monetize small renewable resources in the absence of subsidies. Innovations in energy storage would introduce a significant amount of flexibility for P2P energy trading. However, issues related to the role of distribution utilities and their cost recovery under the new paradigm, as well as potential conflict between P2P marketplace and the bulk power system, need to be resolved (for examples, scheduling of energy storage by prosumers might interfere with the balance of local generation and consumption).

4.3 Aggregator

With the growth of DERs, the aggregation of small resources to create a sizable capacity that acts as a single valuable resource is an important business opportunity (IRENA, 2019b). By bundling and controlling resources – such as rooftop solar PV, home batteries, cooling equipment, demand response, EV charging stations – in real time, the aggregator coordinates these scattered, customer-owned assets and creates a so-called virtual power plant (VPP) capable of providing services to the wholesale market, retail market, or electricity network operators (transmission anddistribution). VPPs often have the same technical capabilities of traditional power plants and thusreduce the need for investment in conventional generation and network capacities – and the associated tariff increases.

Despite the high potential of resource aggregation and its proven performance in other countries such as the USA, the UK, and Australia, the experience of India with this business model has so far been limited. Indeed, India has not gone beyond a few aggregation-based pilot demand response programmes. It is likely that two primary reasons have contributed to the slow uptake of this business opportunity. The current regulatory framework of India's electricity market has neither a system of defined resource aggregation nor the role of aggregator (Das and Deb, 2020). The resulting regulatory

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vacuum results in a high level of uncertainty for potential entrants into this area. Furthermore, there is no established competitive ancillary service market in which aggregators can participate. Ancillary services are short-term and often fast-response products, features which match the technical characteristics of DERs. The presence of an ancillary service market improves the economics of aggregation, as fast-response services are often more expensive than conventional energy or capacity products.[12]

An important consideration relating to aggregation is the role of Discoms in such activities. As the Indian distribution utilities might become unbundled in the future (in other words, through separation of carriage and content) there are four possible models which could be used to define the aggregator's role, with different level of involvement of Discoms (Das & Deb, 2020).

- The first model assigns the responsibility of aggregation to Discoms. This is straightforward within the current market structure in India and it gives more control to Discoms over DERs. Nonetheless, it leads to a monopoly aggregation market and also Discom may have neitherthe incentive nor the technical knowledge/capacity to engage in aggregation efficiently.
- In the second model, an independent aggregator is allowed to bundle resources and sell them to the distribution utilities. This is better than the previous model, but still not very efficient as there would be only one player and the risk of market power exists.
- The third model allows for a competitive aggregation market without Discom participation
- The fourth model is a hybrid arrangement in which both independent aggregators and Discoms participate in the market.

The last two add a degree of contestability and introduce agents with innovative solutions and digital capabilities.

There are some factors that need be considered in choosing the optimum structure of aggregation market. First, if distribution networks in India become unbundled at some time in the future, aggregation of distributed resources by the Discom might be considered an infringement of unbundling (although the regulator might decide to exempt aggregation from the list of activities that Discoms are disallowed after unbundling). Second, it is always more efficient to utilize competition where possible, by lowering barriers to entry for independent aggregators, as it facilitates innovative business models and improves efficiency. There is, however, a tradeoff here between coordination and competition. The direct involvement of Discoms in aggregation activities can improve the coordination of DER use, whereas the presence of independent aggregators promotes competition. The experience of other countries, such as the UK, shows that with the increase in the growth of DERs, Distribution Network Operators (DNOs) should take on system operator functions. The new role – which is called Distribution System Operator (DSO) – entails engaging in active network management via real time operation of DERs.[13] In any case, the regulator might choose the desired model of Discom involvement in aggregation business based on an optimum balance between competition and coordination in this context.

Another important point is that aggregation is a data-driven business model. The aggregator needs to collect real-time data from DERs in order to successfully bundle various resources and offer them in the

[12] The Central Electricity Regulatory Commission announced a draft policy on Ancillary Service Markets in 2015 (Ancillary Services Operations Regulations http://www.cercind.gov.in/2015/draft_reg/draft%20cerc%20ancillary%20services%20operations%20regulation s.pdf) but this has not yet been finalized.

[13] It is also possible to have DSO and DNO as separate entities. However, unlike the retail segment for which there is a consensus among experts to be separated from the network function there is no agreement among experts to have two entities for network and system operations at the distribution level not least because of loss of economy of scope. In the UK, for example, DNOs have been transforming to become DSOs so only the retail part is unbundled. The situation is totally different at transmission level for which network operator and system operator are legally separated.

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electricity market. This, however, requires advanced metering infrastructure, two-way communication systems, network remote control and automation systems, and advanced forecasting tools (Das & Deb, 2020). In order to achieve these, significant investment is needed in the digitalization and deployment of smart grid infrastructures. How this investment will be financed is another unresolved issue in the deliberations concerning distribution grid modernization in India.

5. Market design for distributed energy resources

The current electricity market design in India, which is dominated by long-term PPAs between power generators and distribution utilities, is one of the key weaknesses of the country's electricitysystem. Distribution utilities pay an availability-based tariff (ABT) to generation companies; this covers their fixed and variable costs as well as deviations from the schedule. This model was introduced to improve security of electricity supply and incentivize grid discipline but at it had (unintended) consequences. The dominance of long-term contracts, along with the ABT, have notonly contributed to the poor financial performance of distribution companies and renewable energy curtailment, but have also prevented efficient price discovery which is key to the integrationof DERs (Singh, 2019). Furthermore, as capacity shortage and frequency imbalance are no longer issues in the Indian electricity system, the ABT may not be compatible with the new realities of thepower system (IEA, 2020).

Market design for DERs primarily means having rules in place that lead to efficient price signals that guide investment and operation of these resources. Currently, the ultimate market arrangement that would enable decentralized resources has not yet been agreed upon among experts; however, many trials and pilot projects are exploring potential designs. Some of these experiments investigate changes to existing market arrangements, while others focus on entirely new designs, such as: platform markets (Weiller, andPollitt, 2013), two-market solutions (Keay and Robinson, 2017), and reforming the role of distribution network utilities.

In the context of India, a set of reforms is likely to be crucial in order to align the electricity market with the growth of DERs. One much-needed measure is to move towards more liquid and short- term markets with shorter settlement periods, to enable optimal dispatch of renewable resources(IEA, 2020). Also, the presence of such markets paves the way for the participation of aggregators–intermediaries that run virtual power plants by bundling DERs (Xu, 2019). India recognizes the importance of short-term markets. An intraday market seems to have already been introduced in the power exchange to enable adjustment of positions closer to real time; however, the level of trade in this market remains limited compared with the contract market.

Another important reform is the establishment of an ancillary service market. Ancillary services are one of the key pillars of the electricity market as they provide services to maintain: (a) load-generation balance (frequency control), (b) voltage and reactive power support, and (c) generation and transmission reserves (CERC, 2019). This market is likely to be the most suitable one for incorporating decentralized resources, given that they are more economically competitive in providing short-term flexibility services (Xu, 2019). Some efforts in this direction are happening in India using public sector-owned generation assets, but a functional ancillary service market is still not in place. Currently, interstate thermal generators are obliged to provide these services and there is no renumeration for Discoms and other resources for provision of ancillary services (IEA, 2020).

The necessary market reforms are not limited to the wholesale market. Indeed, a key part of the solution to the future growth of DERs lies in the retail electricity market. The separation of supply from network business is a precondition for creating of a competitive retail electricity market. A competitive retail market can promote active participation of DERs when they are subject to the correct price signal – such as time-of-use tariff. This also means price distortions caused by subsidies need to be removed.

The presence of cross subsidies has a negative impact on competition, especially when the cost of alternative resources declines. Cross subsidies based on purchasing power cause new market entrants

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to find subsidizing customers more attractive than subsidized ones, and thus prefer to serve only this class of customers (Joseph, 2015). This is specially the case when new distribution licensees are exempted from a universal service obligation to lower barriers to market entry for them. The incumbent distribution utilities will thus continue to lose valuable industrial and commercial customers as a result of competitive pressure, unless their tariff is lowered to match that of new entrants (Singh, 2010). This can result in pressure on government to protect distribution utilities from new entrants something which hurts competition further (Joseph, 2015).Thus, the creation of a competitive retail electricity market may not be straightforward if cross subsidies continue to exist. Subsidized consumers need to be educated to make an informed choice between cheap but unreliable electricity versus a more efficient tariff and improved quality of supply.

Also, segregation of the retail tariff to its components (power procurement costs, transmission and distribution charges, costs of network losses, and cost of supply services) can improve the cost efficiency of the electricity supply industry. This is because it allows for better appraisal of regulated segment costs (such as network) and monitoring of the competitive element (such as retail supply)in comparison with the case that all these charges are aggregated. For example, when Discoms are unbundled, they need to be only concerned about technical energy losses in their network, whereas retail suppliers will be responsible for commercial losses.

When it comes to reforming the electricity market of India, the more complex challenge is likely to be that of addressing the issue of legacy PPA contracts (Singh, 2019). A mechanism is needed to remunerate generation companies for their investment while freeing distribution utilities from a situation in which they pay higher tariffs, while at the same time alternative cheaper sources of power become increasingly available. CERC is cognizant of this issue and is consulting about changes to market design (IEA, 2020). One possible option is to separate financial obligation of legacy PPAs from the physical dispatch of the holders of these contracts. The generation companiescan have a guaranteed payment but be asked to participate in the short-term market for dispatch.In this way the PPA could be converted into a contract for difference (CfD) with a strike price that is settled against the spot market price.

5.1 Opportunities for India to increase grid flexibility through DERs

DERs provide tremendous opportunities for India to advance its power sector reform further, with a view to utilizing decentralized flexibility. IEA (2021) predicts that the need for flexibility in the Indian power system will rise faster than anywhere else in the world, not least because of ambitious renewable targets which require 450 GW of non-hydro capacity by 2030. Integrating this level of non-dispatchable generation requires an effective transformation of the power sector to enable flexible operation of existing power plants as well as incentivization of new sources of flexibility.

Although flexibility can be provided by various resources – such as hydro power, coal power plants,and gas power plants – it is expected that the load factor of thermal generation will decline further with the rise of asynchronous generation. Furthermore, many of India's existing coal power plants were not originally designed for flexible operation, which means that technological modifications are likely to be required to make them more flexible. A significant increase in the capacity of hydropower, on the other hand, is likely to face environmental and geographical constraints. These all suggest that the role of DERs in providing the needed flexibility in India's future power system cannot be overstated.

A lack of development of sufficient flexibility resources would likely result in increased renewables curtailment and in increased costs of achieving decarbonization targets. The key question thus facing policy makers is how to unlock the flexibility provided by DERs.

Historically, most development in the power industry has happened in the upstream (in the areas of bulk power generation technologies and the wholesale market), but with the rise of decentralization, decarbonization and digitalization the downstream of the power sector has gained significant importance. The challenge is that this segment is the weakest part of the electricity sector in India.

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Enabling flexibility of DERs entails a new thinking about the reform of theIndian power sector both at the level of market design and regulation.

In addition to issues of rationalizing retail prices, removal of cross subsidies, introducing ToU tariffsand resolving the issue of legacy PPA contracts, the overall electricity market needs to be designedin a way that creates a level playing field both for supply-side and demand-side resources – in other words, a two-sided market. According to Khorasany et al. (2020), a two-sided market is a market arrangement that enable direct interaction of both supply and demand resources through an intermediary or platform, such that the decision of each set of agents affects the outcome of the market (Figure 12). This market model not only increases power system flexibility but also provides a range of other benefits. Under a two-sided market, end users have access to clean local energy sources, network tariffs are less complex, and energy prices react to the users' level of consumption. In addition, those with DERs can participate in local flexibility markets to provide network support services.

As the cost of energy varies across time and space, the most economical way of running a two-sided market is to extend the granularity of pricing to low-voltage levels through distribution nodalpricing. This encourages users at nodes with high prices to increase supply and reduce demand, and users in low-priced nodes to act in the opposite way. However, despite the theoretical efficiency, this model has two main drawbacks that are especially relevant to developing countries(Robinson, 2019).

1. Distribution nodal prices can be technically very complex because distribution (as opposed to transmission, which has only a few hundred nodes) has several thousand nodes.
2. Nodal pricing runs into difficulties in countries where regional differences in prices are politically sensitive. Therefore, the market designer faces a tradeoff between technical complexity, economic efficiency and political acceptability.

Given the cost and complexity of full nodal pricing, alternative approaches can be used to improve economic efficiency in the context of a two-sided market. These include: integration of demand response, enabling aggregation of small resources and P2P trading. The precondition is, however, investment in ICT-enabled systems at different levels of the electricity grid. This enables end-users to exchange data and control/monitor their devices, and for the network providers to collect this information in order to improve the accuracy of their demand forecasts, which is a key input in the optimization of network assets with increasing levels of DERs (Khorasany et al., 2020).

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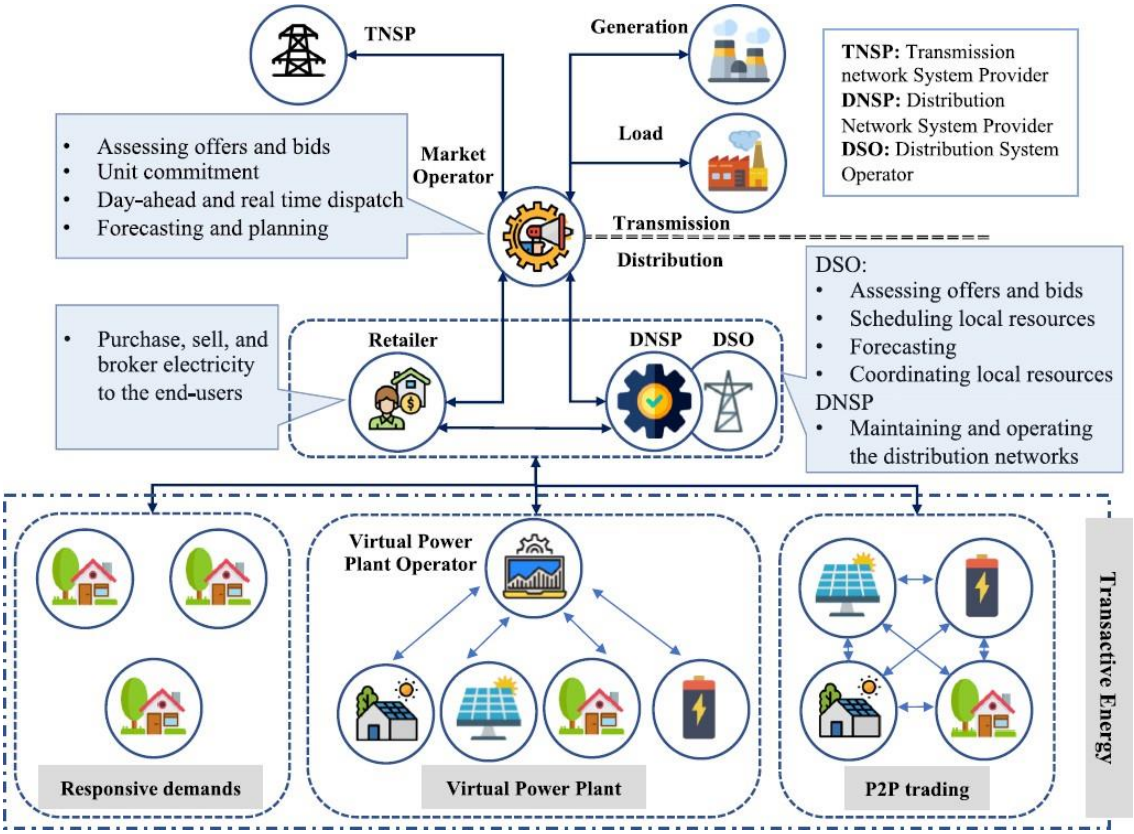
Figure 12: An overview of a two-sided market



Source: Khorasany et al., 2020

6. Conclusions

As in many other countries around the world, India's electricity system has traditionally been a centralised system relying primarily on large-scale thermal generation. In recent years, however, a mix of policy- and market-driven incentives have resulted in the rise of renewable energy in the generation mix, both at utility scale and distributed energy resource (DER) levels.

In the power system, the success of DER initiatives, largely depends on the context of the electricity industry –such as its renewable incentive models, its operational, and market design, its regulation and its fundamentals of supply and demand. The electricity market of India requires some important reforms to align it with the growth of the decentralization paradigm.

The most pressing reforms are required in the distribution sector, including distribution networks, retail supply, and retail tariffs. The current scope of distribution licensees' operations includes both network and retailing. This means that the Discoms will not benefit from the growth of distributed resources owned by customers thus they have an incentive to resist their uptake. The lack of unbundling- separation of carriage and content- also prevents the emergence of innovative business models in the retail side, as well as the efficient participation of DERs in the electricity market. Furthermore, distribution utilities are stuck with high-cost legacy PPA contracts, which, along with below average cost retail tariffs, high energy losses, and the grid defection of subsidizing consumers, have affected their financial performance significantly. The financially constrained Discoms, in turn, are unable to invest in network development and modernization which further exacerbates the issue of energy loss and their quality of service. Breaking this cycle is crucial for the growth of DERs.

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Integrating distributed resources at higher shares requires an efficient retail price signal, as this is the main guide for the investment and operation decisions of DER owners. In India there is a significant cross subsidy among customer categories. Households pay less than the actual cost of supply, and this has contributed to slow penetration of rooftop solar in the domestic sector. At the same time, the tariff for C&I customers is higher than the actual cost and this incentivizes an inefficient level of decentralization among this class of customer. These in turn risk the financial and operational sustainability of distribution licensees even further.

At the level of market design, the country needs to move towards a two-sided market in which both supply-side and demand resources participate on a level playing field. An efficient design in this context entails increasing the granularity of electricity pricing down to distribution grid nodes,but the downside of this is increased complexity. In the absence of distribution nodal pricing, alternative approaches – such as distribution utility-led local flexibility markets –can be introduced to integrate distributed resources. The precondition for this is, however, investment in ICT- enabled systems at different levels of the electricity grid. There is also a need for liquid short-term wholesale markets as well as for effective ancillary service markets. These markets allow for the participation of DERs through intermediaries such as aggregators. A more advanced coordination mechanism is also needed between TSO and DSOs in order to integrate DERs in an efficient and reliable manner.

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Appendix

A1. Further information about electricity market reform in India

The National Tariff Policy of 2006 mandated the use of competitive approaches for all new generation and transmission projects within the framework of EA 2003. Developers can participate in an auction with a generation plant proposal of their own, or bid for existing predefined projects (in which technology and fuel type are determined by the procurer – in other words, the central or state government) and thus bear fewer development risks (such as land acquisition, environmental permits, and fuel linkage). Bids are separated for energy and capacity components but if there are different requirements for base load and peak load or seasonal tariffs they need to be further disaggregated accordingly.

Grid balancing is governed by the Availability Based Tariff (ABT), which specifies a tariff structure with three components: energy, capacity, and a charge for deviation from the schedule according to the Deviation Settlement Mechanism (DSM). The deviation payment can be positive (for over generation) or negative (for under production) and its rate varies depending on the system condition (under or over frequency). The current rates for schedule deviation charges are lower in comparison with electricity prices in the other markets of the Indian electricity system (for example, power exchange or short-term bilateral markets). This has arguably encouraged grid indiscipline, as generators sometimes rely on the system operator to meet their contractual obligations; a practice that can endanger grid stability.

The process of scheduling and dispatch is a coordinated arrangement between the national load dispatch centre (NLDC), five regional load dispatch centres (RLDCs), and 27 state load dispatch centres (SLDCs). RLDCs plan a day ahead generation schedule based on 15-minute time blocks through coordinating SLDCs as well as generation facilities/customers that are connected to the interstate transmission grid. In practice, RLDCs operate the regional grids as a power pool with decentralized scheduling and dispatch arrangements, in which SLDCs have the operational autonomy to schedule/dispatch their own generation or their withdrawal from the Inter State Generating Station (ISGS). Unlike the intra-state grid operation, in which generation schedule, dispatch, and settlement are mainly manual, the interstate power dispatch process is reasonably automated. Interstate transmission capacity is priced based on point of connection, which allocates transmission costs among consumers according to the utilization of network, location of user in the grid, the distance between generation and load points, as well as quantity and direction of power flow. In allocation of transmission access rights, priority is given to long-term contracts and applications. Congestion management based on curtailment of allocated transmission capacity also follows the same order of priority as transmission access rights.

India does not yet have an established ancillary service market. In 2015, the Central Electricity Regulatory Commission (CERC) introduced regulation for the dispatch of Reserves Regulation Ancillary Services (RRAS) to address frequency excursion as well as extreme events. The initial implementation of RRAS by Power System Operation Corporation Limited (the NLDC) has arguably shown satisfactory performance in addressing some extreme frequency deviation incidences. However, there is still not a sufficient level of frequency regulation service, and the market is yet to evolve to produce an efficient signal for operation and investment.

A2. Regulating electricity distribution networks: RIIO model

The traditional incentive regulatory model of electricity networks in the UK (such as RPI-X) which applied following liberalization, has generally been successful in improving the technical and economic efficiency of distribution utilities. However, a combination of challenges –such as increased reliance on renewable energy, the rise of distributed energy resources, ageing infrastructure, and increased concern related to the social and environmental impact of utilities – rendered the traditional DNO business model outdated. As a result of these challenges, and following extensive assessment, the UK regulator Ofgem has adopted a new regulatory scheme, RIIO. The RIIO framework (Revenue =

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Incentives + Innovation + Outputs) focuses increased incentives on output measures of companies' performance, rather than merely on cost minimization.

The outputs were set through stakeholder consultations which involved Ofgem, network utilities, and customers. To ensure delivery of the RIIO output categories, Ofgem is implementing a range of incentives. Financial incentives (including rewards and penalties) both automatic and depending on a subsequent review of performance, will be triggered during the price control period, rather than being reflected in a revenue change in the following period. Besides financial methods to incentivize the delivery of outputs, company performance related to each category will be published and made available to the public. Reputational incentives of this kind can be effective, particularly if the company is involved in competitive segments beyond their regulated venture.

One of the key aspects of the RIIO framework is to encourage network utilities to play a part in providing a sustainable energy future. Part of that is reflected in the length of the regulatory period, which has increased from five to eight years. As part of their business plans, each utility company must justify why investments take place at a certain time, and Ofgem aims to find the most cost- efficient timings possible for current and future customers. In an industry that involves assets of importance for the functioning of an economy as a whole and with an economic life of up to 40 years, long-term planning is vital.

The other important aspect of the RIIO model is the total expenditure approach (totex). This approach combines a portion of utility capital expenditures (capex) and operating expenditures (opex) into one regulatory asset that allows a rate of return on both, based on a predefined percentage split. This eliminates the incentive for over capitalization and excessive investment in hard assets such as wires and transformers. Instead, it encourages distribution utilities to seek themost cost-effective solution for network issues. One example of these incentives is for companiesto retain a percentage of their cost savings during the regulatory period, if they contract the services of DERs as an alternative to grid capacity enhancement in order to manage congestions in the distribution grid.

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