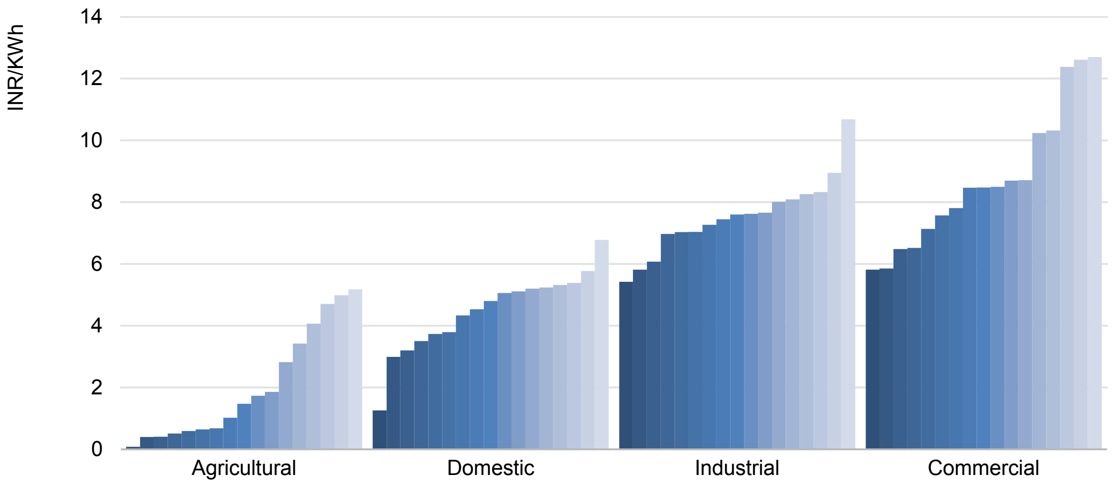
user prices for more energy-intensive industrial consumers in order to cross-subsidise the lower tariffs paid by low-income residential and agricultural users.

Industrial electricity prices in India at USD 99/MWh are significantly higher than residential prices at USD 69/MWh (on a nominal basis). The relatively high industrial prices drive large numbers of industrial users in India to procure electricity from generators directly (open-access contracts) instead of through the DISCOMs. Open-access prices are on average 20-30% lower than utility prices. Alternatively, industrial users may also invest in their own generation. Captive generation in India represents over 10% of all electricity generation in the country.

Prices also vary, not just between end users, but also across states. Electricity tariff setting in India is under state jurisdiction. State electricity regulatory commissions set tariffs based on state regulations and state objectives. Consumers in some states pay five times more for their electricity than their counterparts in neighbouring states. For example, Maharashtra, home to India's financial and business centre, Mumbai, has the highest commercial (INR 12.7/kWh) and household (INR 6.8/kWh) electricity prices of all Indian states. Agricultural use is generally unmetered, resulting in very low revenue collection rates for the DISCOMs, and low water and energy efficiency for the agricultural users.

Electricity prices in Indian states, 2019



Sources: IEA analysis based on Power Finance Corporation data, calculated from each state's DISCOM revenue per kWh for each category of consumer.

In the future, electricity prices and tariff design could become one of the most important tools to enable more demand-side flexibility in India. Electricity tariff design and tariff options may need revision with the increasing share of renewables as the timing of different consumers' use of the system will become critical, especially at times when solar generation is high. Tariff changes can shift significant user volume from low solar times to high solar times and therefore save system-level costs, which in turn leads to greater affordability.

Currently time-of-use (TOU) tariffs are implemented by most states in India and are applicable to large industrial and commercial consumers. In some states these are referred to as time-of-day tariffs. Depending on the state, the surcharge for consumption in peak hours varies from 10% to 20% compared to rebates/concessions that vary from 15% to 25% in off-peak hours. Reflected in TOU tariffs, some states have two peak periods (a morning and an evening peak), such as Gujarat and Maharashtra, while other states have one peak period per day, such as Karnataka.

TOU tariffs are a critical policy requirement for tapping into flexibility from industry, buildings (including cooling demand), water heating demand and other household electricity uses, and EV smart charging. Additionally, tariff reforms can help move from the current practice of agricultural demand shifting, where agricultural users play a passive role, to proactive agricultural demand response, where farmers respond to a price signal and benefit financially from providing flexibility. Similarly, demand response from cooling loads and EVs would critically depend on the price incentives given to consumers.

International examples of how tariff systems can better align solar generation with peak demand are the TOU tariff policies implemented in California, Denmark and the United Kingdom.

The California Public Utilities Commission (CPUC) TOU tariff is a rate plan in which rates vary according to the time of day, season and day type (weekday, weekend or holiday). Higher rates are charged during the peak demand hours and lower rates during off-peak (low) demand hours. Rates are also typically higher in the summer months than in the winter. This rate structure provides price signals to energy users to shift energy use from peak hours to off-peak hours. The chart below illustrates the California TOU tariff design. Red indicates high price periods, yellow indicates moderate price periods and green indicates low price periods. TOU pricing encourages the most efficient use of the system and can reduce the overall costs for both the utility and customers. Prices are predetermined for each time period. Prices do not adjust according to day-to-day changes on the wholesale electricity market.

Illustration of the California TOU tariff design

	Weekday	Weekend
Early morning		
Midday		
Afternoon/Evening		
Overnight		

Source: CPUC.

By 2020 all commercial, industrial and agricultural customers in California were already required to be on a TOU plan. The plan is also mandatory for any consumer with a rooftop solar system, including residential consumers. It has been available as a choice for more than 10 years for other residential users as well, but very few residential consumers actually switched to use these rates. As required by the regulator, the state's three investor-owned utilities started to shift their 22.5 million residential consumers to default TOU rates in 2020, making the TOU rate the default rate for everyone as opposed to an opt-in option. This is important because residential electricity users are known to be sticky and passive users, and as such most users remain on the default rates because they simply prefer to avoid the administrative process of switching to another rate. During the pilots, the Californian utilities demonstrated that for every 10% increase in the ratio between the peak and off-peak TOU rates, peak demand decreased in a range of 6.5-11%.

The exact rules on TOU tariffs and metering together also determine the value allocation across the rooftop solar owners, non-rooftop consumers and the utilities. For example, since 2016 all rooftop solar customers of regulated utilities in California are required to be on TOU rates. This allows the utility to mitigate its revenue loss by shifting the TOU peak period. In California TOU peak periods have shifted from 11:00-18:00 to 16:00-21:00 as rooftop solar deployment and demand response have reshaped the demand curve.

As the bill savings of a rooftop consumer will be equal to the revenue loss of the utility, TOU rates reallocate the costs and benefits between utilities and rooftop users. The TOU tariff will typically result in higher rates in the evenings in California between 16:00 and 21:00. (when solar generation is lower), thus compensating utilities for providing energy during peak hours to rooftop solar consumers. At the same time, the rooftop solar owners tend to overproduce in the middle of the day when the feed-in rate falls into the lower rate category.

Many Indian DISCOMs are already in a weak financial position and expressing concern about the further loss of revenues from, and increased cost of integrating, rooftop solar. The example of California shows that mandating TOU rates for all rooftop solar customers also helps mitigate some of the utility's revenue loss.

Requiring all rooftop solar customers to be on TOU tariffs can help mitigate the revenue loss of DISCOMs while also balancing the cost shift between rooftop solar customers and non-rooftop customers. Regularly revising the TOU timeslots will be required as rooftop solar additions and demand response reshape the state load curves.

In other markets, such as Denmark since the end of 2020, retail customers have been able to pay according to their hourly consumption and the hourly price, such that the day-to-day and hour-to-hour changes in the wholesale electricity market are reflected in the end-user tariff. This requires a certain level of detail in metering capabilities. However, before hourly meters were installed, customers with a consumption of over 100 000 kWh/year were required to settle according to the hourly price. In this way larger customers were exposed to the hourly variation in the wholesale electricity market.

The United Kingdom's journey towards TOU tariffs has been gradual and underpinned by consumer awareness and engagement programmes. The success of static TOU tariffs in the United Kingdom encouraged rollout of dynamic TOU tariffs. This had been largely possible due to consumer acceptance of these programmes, and presents a case for applicability in the Indian context as well.

In India, tariff reforms could include expanding TOU pricing to more customers, including residential users, adjusting peak tariff slots (as seen in a Maharashtra Prayas proposal) and switching more users (including residential and rooftop users) to default time-dependent tariffs.

India has yet to undertake a systematic pilot to discover the impact of TOU prices on peak load. Some of the main enablers for developing advanced metering infrastructure for TOU tariff implementation include pilot demonstrations, institutional strengthening, innovative business models, and consumer awareness and engagement programmes.

Digitalisation and smart tools are prerequisites for TOU tariffs and thus for demand response

The international examples in the previous chapter were made possible by widespread digitalisation and the use of residential smart meters in those countries. Additionally, smart meters need to be coupled with other digital tools such as displays, notification systems or systems providing automation to allow demand response.

Smart meter deployment in India is still limited. As of March 2021, 2.3 million smart meters had been installed, deployment for 7.6 million is ongoing, and another 1 million are in the pipeline, according to the National Smart Grid Mission. The more widespread rollout of advanced metering, coupled with the results of ongoing studies, can create a foundation for the introduction of TOU tariffs in some Indian states. For example, a study by the India Smart Grid Forum (ISGF) is currently looking at TOU reform prerequisites in Gujarat in collaboration with the state regulator. This study identified advanced metering infrastructure, energy management software and smart switches and devices as minimum technical requirements for Gujarat. Furthermore, it emphasised the need for regulatory change, the importance of keeping consumers informed, and the need to respond to consumer requests for an explanation of the benefits of the tariff, including the exact impacts of new tariff types on bills.

Under the UK-supported Power Sector Reform Programme in India, the National Smart Grid Mission has developed the Smart Grid Readiness – Self Assessment Tool, which provides a common framework to help utilities better understand the smart grid modernisation journey and to prepare them for this transition by assessing gaps, including in regulations for TOU tariffs.

An international example of a comprehensive digitalisation policy is the UK's Smart Systems and Flexibility Plan. It is designed to remove barriers to participation in demand-side response by large consumers, and enable smaller consumers (e.g. domestic) to participate in demand-side response at scale in due course. Key actions include the rollout of smart meters and the move towards market-wide half-hourly settlement, together providing a framework for the increased provision of smart tariffs.

Consumer protection is a core consideration as the United Kingdom transitions to a smart energy system. The government intends to set regulatory requirements for certain smart appliances that are suitable for flexible consumer use, e.g. fridges and washing machines, to support their uptake and to guard against potential risks, including those relating to data privacy and cybersecurity. In tandem, the UK government is working with the British Standards Institution to support the development of technical standards for energy smart appliances, including EV charging points and domestic demand-side response, via public consultation. The UK government is also exploring what innovation may be needed to engage and protect vulnerable and low-income consumers in a smart energy system. This would similarly be important for India in the longer run.

Power plant flexibility potential remains largely untapped for states today

Most states are concerned about the future role of existing coal power plants. On the one hand, with the country's ambitions to supply more generation from renewable technologies, coal plants are expected to operate less, which leads to reduced revenues. And on the other hand, in order to operate flexibly and meet stricter emissions standards, many existing plants also require further investment. Such investment needs to be weighed against investment in flexibility in other parts of the system and in light of emission reduction targets. Government officials express concern that historical dependence on long-term coal power procurement contracts, as the tool for ensuring capacity adequacy, creates an economic burden by locking in long-term fixed capacity payments for coal power plants.

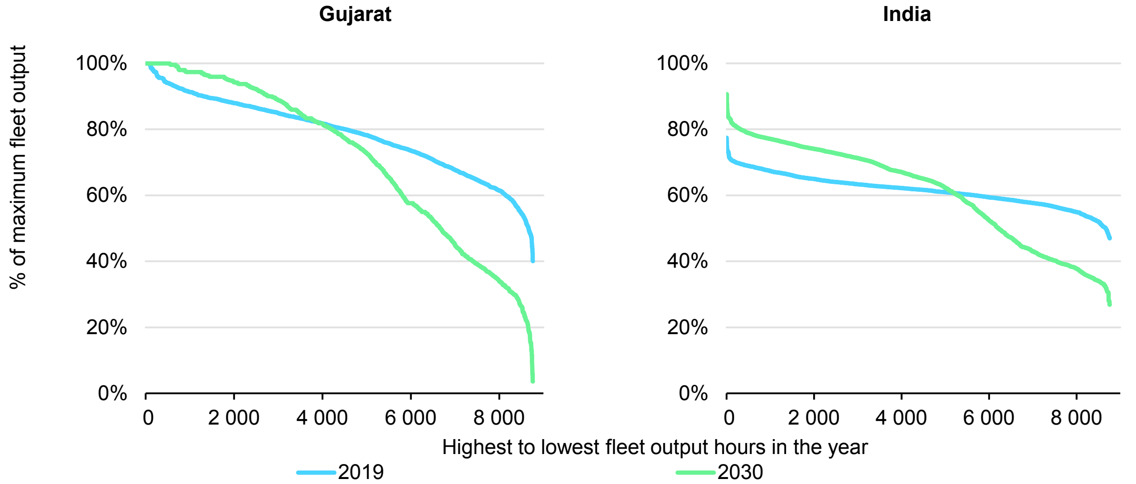
In the STEPS of the *World Energy Outlook*, India's power system in 2030 is projected to have 269 GW of coal capacity, higher than the 235 GW capacity in 2019.

In certain states, power plant flexibility will become increasingly important with the growing deployment of solar and wind. For coal-fired power plants, flexibility includes faster start-up times, higher ramp rates, lower minimum stable levels, and shorter minimum up and down times, as well as the ability for warm and hot starts. Lower minimum stable levels are important for allowing power plants to keep operating while accommodating high VRE output in certain hours, particularly for solar generation in the middle of the day.

India has national-level coal-fired power plant flexibility directions that apply to centrally operated power plants, while state-operated power plants have their own flexibility objectives. Considering that most scheduling is under the control of SLDCs for balancing state-level demand with supply, it is important to assess and set flexibility requirements at the state level on a plant-by-plant basis. For example, Gujarat's state-owned generation company, GSECL, targets faster start-up rates and higher ramp rates (1% and 3% of plant capacity per minute respectively), and has introduced pilots to test the feasibility of 55% technical operating minimums for older plants and 40% for newer ones. These pilots go well beyond the current operating minimums of 75% for older and 50-65% for newer coal-fired power plants in Gujarat.

The IEA Gujarat State Model and India Regional Model show that the use of coal-fired power plants in India will change dramatically by 2030. While the capacity factor of coal-fired plants at the national level remains almost unchanged from 55% in 2019 to 57% in the STEPS in 2030, this small change masks a much greater change in operating patterns, with much more frequent ramping and a wider range of whole-fleet output levels. Use will shift from baseload operation to more frequent or deeper cycling. This change in operating patterns is seen at the all-India level, and will be intensified in renewables-rich states such as Gujarat. At the same time, the use of gas-fired power plants in Gujarat is expected to change by 2030, with their capacity factors increasing. Gas-fired power plants are expected to contribute to the flexibility of the system by helping to meet evening and night-time demand, and running at low output or shutting down during periods of high renewable output in the daytime. Gas-fired plants also help to meet seasonal flexibility needs, with evening output increasing during the highest net load periods in September and October.

Coal fleet-level generation duration curves for Gujarat and India, 2019 and 2030



Source: Based on IEA Gujarat and India Regional Model.

The IEA Gujarat analysis shows that the impact of increased power plant flexibility by 2030 is a relatively modest reduction in curtailment (from 7.0% to 6.4%) and a reduction in variable operating costs of 1.2%. In some states and for certain plants, this additional operational flexibility will require investment and the redesign of compensation for these power plants, with more focus on compensation for flexibility compared with the current dual tariff solutions (fixed and variable compensation). In Gujarat the state regulator, GERC, is introducing a new tariff system to compensate for the financial impact of ramping up and down at conventional plants.

In Maharashtra the state regulator, MERC, in its recent new Grid Code has provided a compensation mechanism for this flexibility. Andhra Pradesh is another example, where the Andhra Pradesh Power Generation Development Company Limited (APPDCL) has created standard operating procedures for increasing flexibility of coal-fired power plants in the state, including regulations on technical operating minimums for plants, efficient market designs, and economic incentives (tariff structuring) sponsored by the UK under the Power Sector Reforms Programme.

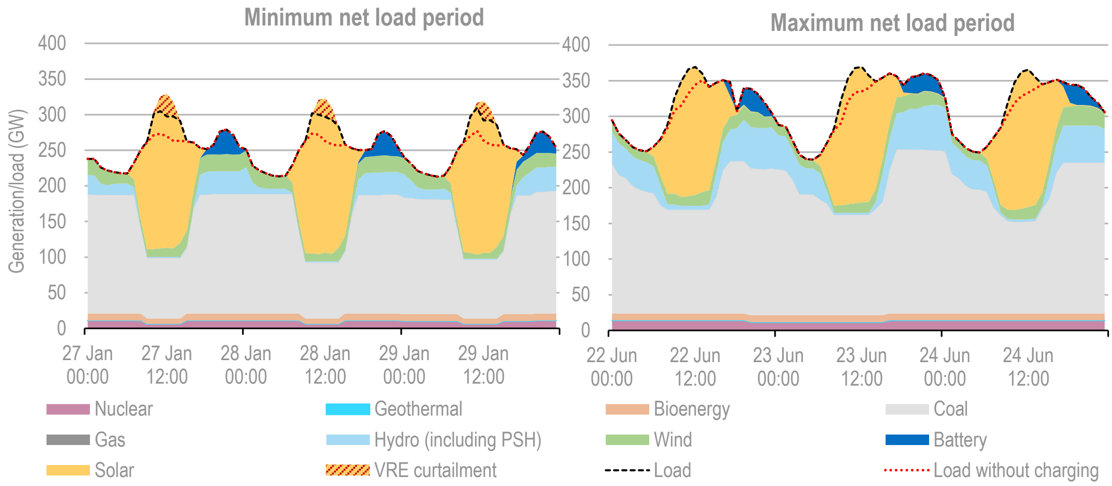
In the longer term, state-level ancillary service regulations and markets, combined with improved spot market participation, could help to remunerate flexible plant operations on a competitive basis with other flexible resources such as demand-side response, storage and grid flexibility.

Batteries and pumped-storage hydro can improve system flexibility, but a regulatory framework is missing

Hydropower currently provides significant power system flexibility in many renewables-rich states, including Karnataka, Maharashtra and Tamil Nadu. In the future, energy storage, such as the combination of batteries and pumped-storage hydro, may increasingly provide flexibility for integrating renewables. Storage is particularly relevant in India for allowing high solar output during the day to be stored for later use to meet evening demand.

In the IEA national analysis for the STEPS in 2030, 76 GW of hydropower, including pumped-storage hydro, reservoir hydro and run-of-river with pondage, provides critical flexibility to meet multi-hour ramps from sunlight hours into the evening when solar generation falls off rapidly. Batteries also become an important source of energy storage, accounting for 34 GW capacity. This helps absorb solar generation during the day and meet peaking requirements in the evenings.

Dispatch of generation and storage during high and low net load periods for India in the Stated Policies Scenario, 2030



Source: IEA, India Regional Model.

At the state level, Karnataka and Gujarat are actively considering retrofitting their existing hydro plants to operate in pumped-storage mode to help with the integration of renewables in their systems. In Karnataka, the retrofit is foreseen for a 2 000 MW hydro plant, while in Gujarat the retrofit is foreseen to restore pumping to the 242 MW Kadana plant and add 1 200 MW of pumping capability to the Sardar Sarovar hydro plant.

To evaluate the impact of pumped-storage hydro on a system with otherwise limited flexibility resources, IEA analysis includes a scenario requested by the Gujarat government to reflect their investment plans at the Kadana hydro power station (242 MW) and the Sardar Sarovar power station (16% of 1 200 MW allocated to Gujarat, thus 192 MW capacity modelled). In this case, curtailment is reduced by 0.5%, market purchases by 4% and variable operating costs by 1% compared with the limited flexibility case.

Another scenario requested by the Gujarat government shows that the addition of a 4 GW, four-hour duration battery reduced curtailment to 2%. Market purchases were around one-quarter less and variable operating costs were reduced by around 7%, including the cost of market purchases. This larger impact is mainly due to the larger battery size and higher efficiency of the battery relative to the pumped-storage plants (81% round-trip efficiency for batteries relative to 60% efficiency for Kadana and 75% for Sardar Sarovar).

For short-duration power system flexibility needs, battery storage co-located with solar generation is a more cost-effective solution than a pumped-storage hydro