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WORKING PAPER

SUPPLY AND DEMAND SCENARIOS FOR TAMIL NADU'S ELECTRICITY MIX TO 2030: IMPLICATIONS FOR THE STATE'S ENERGY TRANSITION

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EXECUTIVE SUMMARY

Highlights

- Given the indebtedness of Tamil Nadu's electricity distribution company, it is important that the state consider the role of demand—and its implications on costs and the energy balance—in its long-term capacity planning.
- To assist with this, this paper develops three demand and four supply scenarios through 2030–31 to yield 12 combinations for the state's future energy balance.
- Achieving this balance is most feasible if the state undertakes an ambitious energy transition in line with current targets; if the effects of COVID-19 curtail demand in the longer term, this balance is still achievable under a medium transition scenario in which renewables constitute 31 percent of total generation.
- Such analyses can aid in the state's integrated resource planning processes and financial investment decisions, and they can be adapted for use across states nationally.
- This analysis was conducted during the peak of COVID-19. However, variables impacting supply and demand can be dynamically altered based on plausible scenarios in the short, medium, and long term to show different effects of COVID-19, recovery pathways, and the respective needs of the user in the modeling tool.

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Although the state of Tamil Nadu is highly industrialized and rich in renewable energy (RE) resources, its electricity distribution company is heavily indebted. The state has taken several steps towards building up the share of renewables in its installed capacity (more than 45 percent) and generation (more than 25 percent; CEA n.d.). The lockdown induced by the COVID-19 pandemic has further aggravated its financial situation because a more substantial share of electricity demand shifted from the the commercial and industrial sectors, with high-rate-paying consumers, to the subsidized residential sector, where the revenue share is not significant. In assessing the state's finances and planning for its long-term capacity additions, it is important to consider the role of demand and the implications on the cost of electricity and energy balance.

Despite Tamil Nadu's status as an industrial heavyweight in the country (with gross domestic product growth averaging 8 percent over the last three years), certain sectors, particularly electricity, have had perennial financial challenges. The losses of the state utility—the Tamil Nadu Generation and Distribution Corporation (TANGEDCO)—grew from ₹4,348 crore in fiscal year (FY) 2017 to ₹11,964 crore in FY2020. Within a week of the first COVID-19 lockdown in 2020, the utility had reportedly lost nearly ₹1,260 crore in revenue (Sivakumar 2020). On the supply side, it was observed that electricity production from thermal power plants (primarily coal) dipped drastically owing to coal shortages. From contributing about 20 percent of the state's energy mix in March 2020, it dropped to about 5 percent in April, representing a 75 percent decrease. On the other hand, Tamil Nadu saw nearly a 50 percent increase in generation from solar, wind, and hydro sources between March and May 2020 (SRLDC 2021a). As the output from thermal power plants dropped, wind energy production increased (as the peak wind season is between May and August) and alleviated the energy situation. Tamil Nadu's wind plants remained a steady source of power and acted as a critical fallback option. The lockdowns did not affect the wind and solar units, as, by design, they are inherently meant to work under minimum on-site supervision. This ensures that the power plants continue to function, even under suboptimal conditions.

These lockdowns highlighted many of the utility's current problems, but they also presented opportunities to tackle them. It is worth using these opportunities to reassess demand patterns and their implications in order to enable utilities to better plan finances.

About This Paper

This paper develops three demand and four supply scenarios for Tamil Nadu's electricity sector. It uses a mix of existing forecasts from various sources as well as the authors' own simulations to develop these scenarios through 2030–31. Demand is broken down by sector, and supply is disaggregated by the generating source, yielding 12 scenarios for the state's energy balance.

Key Findings

Achieving a balance between electricity demand and supply is more feasible under an ambitious energy transition scenario, aligning with the state's nine-gigawatt solar target set for 2023. Under this scenario, the share of generation from renewables (not including hydropower) in 2030–31 is 43 percent. If demand is curtailed by the effects of COVID-19 in the short term for one to two years, this balance is still achievable under a medium transition scenario in which renewables constitute 31 percent of total generation.

If the state decides to adopt an ambitious renewables pathway, it should plan to integrate storage to absorb renewable energy generation and avoid any potential curtailments or spillage. Further, an interconnected grid, evolving market mechanisms, and storage systems may help sell surplus power to neighboring states.

As of FY2019, TANGEDCO's total debt was more than ₹1,01,294 crore, equivalent to approximately 6 percent of the state's gross domestic product. With the current financial health of TANGEDCO and the delay in tariff revisions, Tamil Nadu should carefully plan for future power purchases, keeping possible demand growth scenarios in mind.

Conclusions

Such analyses can aid the state in project-level planning and financial investment decisions as well as in integrated resource planning processes, infrastructure planning, capital investment plans, budgets, and multiyear tariff orders. Although the demand scenarios are uncertain, especially given penetration of distributed renewable sources and the evolving impacts of COVID-19, the approach outlined in this paper is replicable across states and over time and can be adapted for energy planning nationally.

1. INTRODUCTION

Tamil Nadu (TN) is among the most industrialized states in India and is currently ranked 2nd in terms of its gross state domestic product (GSDP). The state has consistently achieved a higher GSDP growth rate than the national average over fiscal year (FY) 2017, FY2018, and FY2019, reflecting a strong industrial ecosystem and infrastructure network. This growth has enabled per capita incomes to rise considerably, pushing the state to the 6th position in FY2020, up from 12th in the previous fiscal year. These high levels of commercial and industrial (C&I) output, coupled with rising incomes, have substantially increased electricity demand. Total electricity consumption has gone up 30 percent (TNERC 2017) between FY2016 and FY2020, with the sectors witnessing the highest annual growth rates. In FY2016, the share of electricity sold to C&I customers in TN was 11 percent and 35 percent, respectively, compared with 9 percent and 33 percent nationally (CEA n.d.; MoP 2016).

The Electricity Profile

Research indicates that TN's renewable energy (RE) potential, particularly from wind and solar sources, is 86.4 gigawatts (GW; MNRE 2020). Realizing this potential could help meet this increasing demand; improve energy security; create jobs; support micro, small, and medium enterprises; reduce future greenhouse gas emissions; and avoid the morbidities and mortalities associated with air pollution.

Given this vast potential for RE, in 1986 TN established its first wind turbines in Mullukadu as part of a demonstration project. Today TN has the highest installed capacity of wind energy of any state, hosting a quarter of the nation's installed wind capacity. The state is now further exploring offshore wind opportunities. Together with the National Institute of Wind Energy and the Ministry of New and Renewable Energy (MNRE), the state government has proposed a 1 GW demonstration project that is likely to be operational within the next few years (Kajol 2020).

The state has also leveraged its solar potential by significantly increasing its electricity generation from utility-scale solar power projects and distributed sources. By February 2021, TN had installed approximately 4.1 GW over the previous eight years, including one of the largest solar parks in the country at Kamuthi (SRLDC 2021b). It is also supporting decentralized generation, as exemplified by the state regulatory commission's approval of a ₹2.3 crore pilot solar project at Irumbai village in November 2020 (*Hindu* 2020). This project is expected to deliver an uninterrupted power supply to the village by supplementing power generated through the solar photovoltaic panels with a dedicated feeder supplying power during nonsunshine hours. The institutional setup of TN's electricity system is explained in Box 1.

As of May 2021, the average share of RE (solar and wind) in the state's installed capacity was 41 percent (Figure 1), and the average share of solar and wind in the state's generation mix was 18 percent (Figure 2).This compares favorably with the national share of 25 percent RE, where TN constitutes 16 percent of national RE capacity.

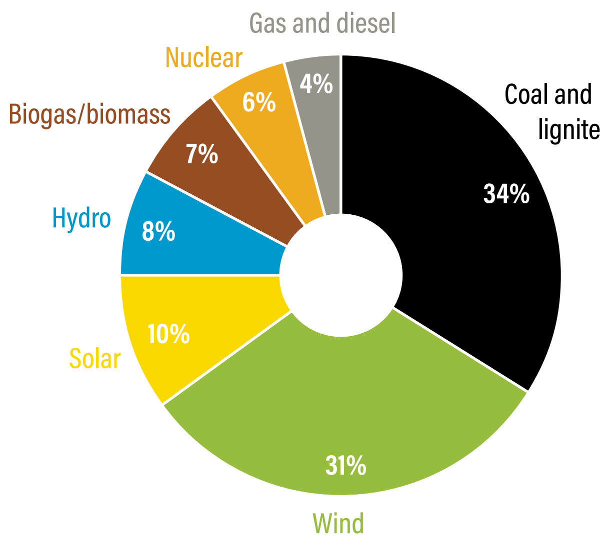
The state has taken several measures to ensure that the demand for power is effectively managed, including time-of-day metering for industrial consumers; distributing energy-efficient (LED and compact fluorescent) lighting appliances; promoting rooftop solar generation for low-tension consumers, including households; and solarizing 20,000 agricultural farms as part of a pilot under the Pradhan Mantri Kisan Urja Suraksha evam Utthan Mahabhiyan (PM-KUSUM) Scheme.

However, TN faces various challenges that impact its electricity sector. As of FY2019, the total debt (MoP 2019) of the Tamil Nadu Generation and Distribution Corporation (TANGEDCO) was over ₹1,01,294 crore, equivalent to approximately 6 percent of its gross domestic product (Pai and Holla 2020). The state's electricity tariffs have not been revised since 2017, but power purchase costs have steadily risen over

Box 1 | Tamil Nadu's Electricity Ecosystem

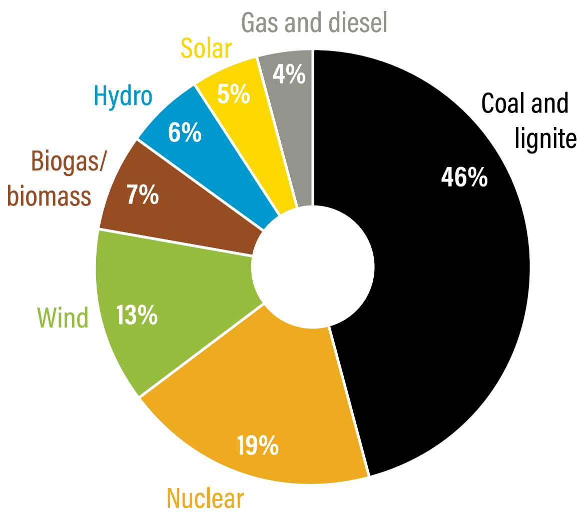
The Tamil Nadu Generation and Distribution Corporation (TANGEDCO), formed in 2010, is one of two subsidiaries of the state electricity board, with the other being the Tamil Nadu Transmission Corporation (TANTRANSCO). Whereas TANGEDCO oversees the overall generation and distribution of electricity in the state, TANTRANSCO is responsible for its transmission planning and operation. The Tamil Nadu Energy Development Agency (TEDA) is an independent agency responsible for improving public awareness of the benefits of renewable energy and transitioning the state to using such renewable sources. The Tamil Nadu Electricity Regulatory Commission (TNERC) was constituted by the state government under the Electricity Regulatory Commissions Act of 1998. TNERC is mandated to enforce standards with respect to the quality, continuity, and reliability of service by distribution licensees and to design an approporiate tariff structure. These entities have jointly shaped the state's electricity profile, making it one of the most diverse energy portfolios in the country.

Figure 1 | **Installed Electricity Capacity, 2019–2020**



Source: WRI's depiction based on compiled monthly and daily data from SRLDC 2021a and SLDC 2021.

Figure 2 | **Source-Wise Generation, 2019–2020**



Source: WRI's depiction based on compiled monthly and daily data from SRLDC 2021a and SLDC 2021.

the years in nominal terms. As of FY2019, the resultant gap between average cost of power and average revenue realization had crossed ₹2 per kilowatt-hour (kWh), resulting in a loss of ₹9,256 crore.

The impacts of the COVID-19 lockdown have further affected the utility's finances. The lockdown has affected close to 44 lakh C&I establishments in TN, and thereby adversely impacting TANGEDCO's operations and revenues because of cross-subsidy charges and the high tariff-paying nature of C&I consumers. Within the first week of the lockdown, it is estimated that the utility lost nearly ₹1,260 crore (Sivakumar 2020). Further, its working capital has been strained because industrial customers sought a three-month moratorium to pay electricity bills. The absence of physical meter reading has also resulted in domestic customers paying the same amount as the previous billing cycle. Even as C&I activities increase, revenue recovery may not be proportionate because many high-paying consumers are gradually migrating to procuring power from captive plants or open access contracts. By August 2020, TANGEDCO had sought a financial relief package of ₹32,682 crore to be able to pay power producers and generation companies (Shivakumar 2020).

These problems may be further compounded if the state goes through with its planned expansion of 8.6 GW for coal, 700.0 megawatts (MW) of allocated nuclear capacity, and 2.5 GW of hydro by 2030 without adequately analyzing demand growth in the future or revisiting the tariff structure frequently (TANGEDCO 2019a).

State Plans and Policy Targets

As part of its capacity planning for the future, TN has primarily relied on policy targets (set jointly by the Tamil Nadu Energy Development Agency [TEDA], TANGEDCO, and MNRE) or capital investment plans submitted periodically for approval to the Tamil Nadu Electricity Regulatory Commission (TNERC) by the state utility, TANGEDCO.

The 2019 solar policy

The state's solar policy, released in February 2019 (TNSP 2019), set a target of 9 GW in solar energy capacity by 2023. Of this, 60 percent is expected to come from the utility category and the remaining 40 percent from the consumer category. Since the release of the policy, TN has installed just under 2 GW of utility category capacity and 143 MW of rooftop solar

capacity. As of FY2020, TN was among the leading states in terms of total installed solar capacity, second only to Karnataka.

The 2019 capital investment plan

TANGEDCO filed a petition with TNERC seeking approval for its capital investment plan (CIP) for FY2020, FY2021, and FY2022. This CIP must be filed periodically by the distribution company, detailing all ongoing projects (both generation and distribution infrastructure) under review as well as new projects that will commence but may be completed either within or beyond the multiyear tariff period. The planned capacity is normally set according to the projected demand across all consumer categories in the state. The projected costs for executing this plan will be considered in the distribution company's overall revenue requirements. This will, in turn, impact future tariffs, subsidy disbursements, and revenue gaps.

Scope and Objective of the Paper

Given the significant untapped RE potential in the state, there is a need for careful planning of capacity addition of generation sources. The plans need to be in line with demand trends in the medium term, especially considering the impacts of COVID-19, proposed retirement of generation assets, plant load factors (PLFs), efficiency levels, and policy targets.

This study aims to undertake a scenario analysis to evaluate a suitable electricity mix for TN until 2030. In this paper, we use existing targets and projections, complemented by assumptions, to simulate future demand against potential generation capacities on an annual basis, taking the following considerations into account:

- Disruptions to demand on account of COVID-19
- Impacts of plant retirements, PLFs, and system-level transmission and distribution (T&D) losses
- Impacts of the state's policy targets

We use data from publicly available sources to aggregate and build a range of annual electricity demand and supply scenarios for the state and compare them to obtain energy balance projections and the future levelized cost of electricity (LCOE). The analysis is expected to help inform TANGEDCO in its medium- and long-term capacity planning.

2. METHODS

We break electricity demand down into five constituent sectors: residential, agricultural, industrial, commercial, and transport. The electricity demand for transport primarily came from railway traction because electric vehicle charging infrastructure is not widespread at this point. Similarly, we disaggregate supply by seven primary sources: coal and lignite, gas and diesel, nuclear, biogas/biomass, hydro, wind, and solar.

Using a mix of the latest available data and recent targets and policies to project future growth rates, we list three demand and four supply scenarios, yielding 12 combinations of future demand and supply situations. The 12 scenarios each carry different implications for the energy balance—the balance between energy demand and supply—assuming constant PLFs or capacity utilization factors (CUFs). The PLF is the percentage of energy sent out by the power plant corresponding to installed capacity in that period and is generally used for thermal, nuclear, and hydro plants. CUF is the ratio of the actual output from a renewable plant over the year (kWh) to the maximum possible output from it for a year (kWh). In this paper, we will use PLF terminology hereafter.

Supply has generally tended towards becoming sufficient in India and in TN. This is borne out by the following figures: Against an all-India peak demand of 183,804 MW, 182,553 MW were met, leading to a shortfall of 1,251 MW. In terms of energy requirement, against 1,291,010 million units (MU), 1,284,444 MU were met—a shortfall of 6,566 MU. For TN, the energy requirement was 108,816 MU, of which 108,812 MU were supplied (near zero shortfall). And against a peak demand of 15,727 MW, 15,668 MW were met (0.4 percent shortfall). Hence, in this study we have shifted the focus from a traditional adequacy assessment based on peak demand—where the idea is to meet demand by increasing supply in as many ways as possible—to meeting demand efficiently at low cost from a financial perspective (CEA 2020a). Therefore, it points towards different recommendations to policymakers for planning future capacity additions and balancing the grid. Sections 3 and 4 discuss the construction of the demand and supply scenarios.

This paper uses two approaches: it draws upon scenarios developed by other agencies, and it complements these with its own forecasts, drawing upon historical trends and policy targets. As such, it is a simulation as well as an aggregation exercise, built in Microsoft Excel.

Other attempts to forecast capacity requirements have used different approaches, restricted mainly to national-level projections. In its optimal generation capacity mix report, the Central Electricity Authority (CEA) assesses the optimal capacity mix to meet India's projected peak demand and annual energy requirement in 2030, set up as a cost optimization project, using an expansion planning model called ORDENA (CEA 2020b). The National Renewable Energy Laboratory (NREL) evaluates India's grid to identify cost-effective actions to integrate RE generation in 2022 (Palchak et al. 2017). NREL uses a production cost model that simulates optimal scheduling and dispatch of available generation by minimizing total production costs. Its *Pathways for Tamil Nadu's Electric Power Sector: 2020–2030* report (Rose et al. 2021) is one state-level study that analyzes the operational needs of TN's power sector to meet the anticipated system requirements to 2030 at least cost. It uses NREL's Regional Energy Deployment System model, which captures the temporal and geospatial representation of variable RE resources. These studies use different methodologies, in part because they rely upon different models and have different scope and boundary conditions; therefore, they are not comparable.

Assumptions and Limitations

This study has three primary limitations. First, since COVID-19 continues to affect the economy, the sectoral and overall demand numbers for 2020–21 and 2021–22 are difficult to project without an in-depth survey on the end-consumer level. Similarly, potential future shifts in policy and targets, which may have implications for supply-side planning, are not incorporated into the study but can be incorporated or updated in future models. Second, we rely upon various state-level data sources for building our scenarios. Although that lends diversity to the perspectives included, the underlying numbers are not easily comparable. For instance, the Tariff Order Note (TNERC 2017) looks at sectoral sales figures and is thus net of T&D losses, CEA's report (CEA 2019b) looks at total demand until 2030–31, and TANGEDCO's CIP (TANGEDCO 2019a, 2019b) looks at subsector demand until 2026–27. Third, since we assume constant PLFs, and given that we hold constant assumptions for costs, depreciation rates, tax rates, and interest rates, the LCOE does not vary across the 12 scenarios covered.

This study only looks at annualized total demand and supply mixes. It does not

- consider short-term generation shortfalls and peak demand scenarios;
- account for plant-wise generation, unit commitment, scheduling, and dispatch operations;
- account for socioeconomic indicators such as income distribution or efficiency improvements;
- model captive and off-grid generation; or
- consider the future implementation of demand-side management and storage.

3. DEMAND SCENARIOS

Demand Scenario 1: Tariff Order Projections with COVID-19 Impacts

For Demand Scenario 1 (DD1), we obtained data for the base year (2018–19) from the approved projections in TN's 2017 Tariff Order Note (TNERC 2017). We note that these are sales projections, as opposed to demand, and are thus net of T&D losses. We then break down growth projections into three phases.

In the first phase, we project growth for 2019–20 based on the three-year compound annual growth rate (CAGR)—of sales figures from 2015–16 to 2018–19 in the Tariff Order Note—for each sector, assuming total demand will grow in a stable manner in the absence of external stimuli.

In the second phase, we incorporate the disruptions to sectoral demand in 2020–21 because of COVID-19 and the ensuing lockdown. To do this, we obtain the sales figures from the Southern Regional Load Despatch Centre's monthly reports (SRLDC 2021a) until February 2021 to note the trends in TN's monthly demand, and based on historical figures, project the monthly demand for March 2021. We scale these numbers so that they add up to the annual totals in the Tariff Order Note. We then assume that all nonessential industrial, commercial, and transport activity is closed in April and May; thus, the entire monthly demand is coming from the residential and agricultural sectors. We assume partial recoveries in June and July. From August onward, we assume a full economic reopening, such that the monthly demand is divided across sectors based on their historical shares of electricity consumption. We thus add the monthly sector shares into their annual totals for 2020–21, which indicates significant falls in annual demand from industry, commerce, and transport and modest increases from households and agriculture.

In the third phase, we assume that growth in 2021–22 returns to earlier levels using a more conservative seven-year CAGR—of sales figures from 2011–12 to 2018–19 in the Tariff Order Note—for each sector, with slight reductions in growth rates over time to account for the more significant base effects and increasing efficiencies. We do not assume that growth overshoots historical rates to rebound from the effects of COVID-19, as we expect these effects to linger until 2021–22. However, based on the estimation, it can be observed that the effects of COVID-19 will be significant on the C&I sector. It may take more than one to two years for the C&I sector to rebound to its 2019–20 demand levels. Hence, it is important for the utilities to plan for these contingencies in the future because C&I sectors contribute a major share in the utility's revenue.

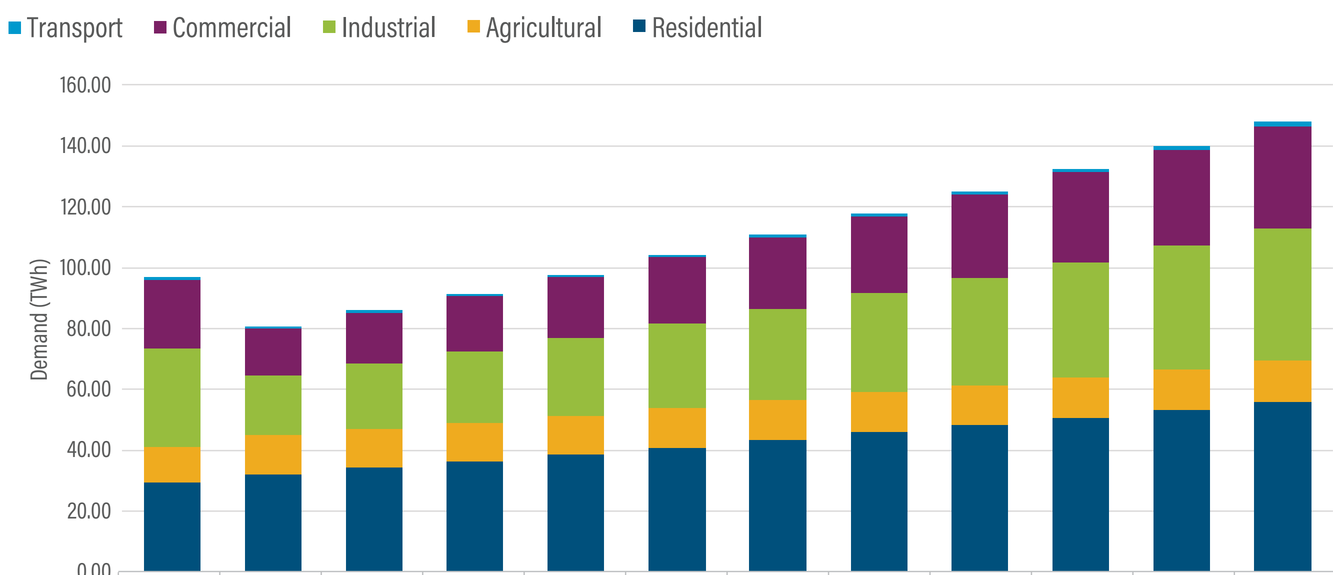
We downscale electricity demand from the agricultural sector by about 0.15–0.29 terawatt-hours (TWh) per year to account for the increasing solarization of the sector through the PM-KUSUM Scheme (Garg 2018; JMK Research & Analytics 2019; MoSPI 2019).[1]

The annual sector-wise demand is shown in Figure 3. In this scenario, overall demand grows an average of 4.4 percent each year to reach 147.99 TWh, net of T&D losses, with the bulk of the growth coming from the residential sector.

Demand Scenario 2: CEA Long-Term Forecasting

For Demand Scenario 2 (DD2), we obtained the total annual forecasted electrical energy requirement for TN from 2018–19 until 2030–31 from the CEA's *Long Term Electricity Demand Forecasting* report (CEA 2019b). For the base year, 2018–19, we divide this

Figure 3 | **Sectoral Demand Projections in DD1**



	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29	2029–30	2030–31
Residential	29.62	32.21	34.36	36.42	38.60	40.92	43.38	45.98	48.28	50.69	53.23	55.89
Agricultural	11.60	12.77	12.70	12.66	12.77	12.88	12.99	13.10	13.22	13.34	13.46	13.58
Industrial	32.39	19.60	21.50	23.43	25.54	27.84	30.06	32.47	35.07	37.87	40.52	43.36
Commercial	22.24	15.27	16.72	18.23	19.87	21.65	23.39	25.26	27.28	29.46	31.52	33.73
Transport	1.08	0.70	0.73	0.77	0.82	0.88	0.95	1.02	1.11	1.21	1.31	1.43

Note: Overall CAGR (2020–30): 4.4%

Source: Based on data from TNERC 2017 and the authors' assumptions and calculations.

total among the constituent sectors using the sector shares for the same year from TN's 2017 Tariff Order Note. For our projections, we then take the respective sectors' seven-year CAGRs from the Tariff Order Note and scale them to the overall growth rates derived from the CEA forecasts, such that the sector shares of demand in any year add up to the totals forecasted by the CEA.

We again downscale electricity demand from the agricultural sector by about 0.15–0.29 TWh per year to account for the increasing off-grid solarization of the sector.

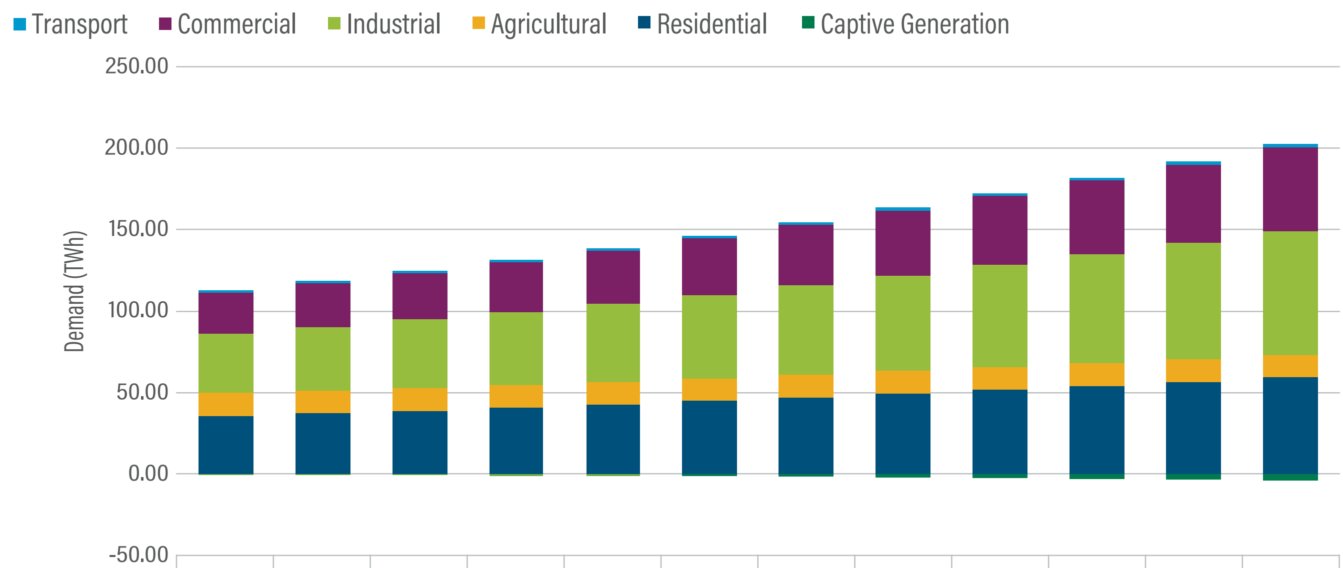
Since this scenario is not based on original projections but works with—and disaggregates—existing CEA projections, the scenario cannot incorporate the impacts to demand from the pandemic and economic lockdown and may thus overstate demand in the short run.

This annual breakdown of demand is shown in Figure 4. Overall demand grows at 5.3 percent each year to reach 198 TWh by 2030–31. The industrial sector is the primary driver of demand growth, though commercial demand doubles too. Agricultural demand remains mainly stagnant.

Demand Scenario 3: TANGEDCO's CIP

For Demand Scenario 3 (DD3), we obtained the annual subsectoral energy consumption and forecasts for 2017–18 until 2026–27 from TANGEDCO's CIP (TANGEDCO 2019b). We add the relevant subsectors in order to obtain the sector totals for the five sectors we consider in this paper for any given year (in TWh). Thus, whereas DD2 relies on disaggregation of overall demand, DD3 relies on aggregating subsectoral demand.

Figure 4 | **Sectoral Demand Projections in DD2**



	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29	2029–30	2030–31
Residential	35.72	37.38	39.15	41.01	43.00	45.08	47.30	49.57	51.90	54.29	56.79	59.38
Agricultural	14.02	13.89	13.77	13.65	13.67	13.70	13.73	13.75	13.77	13.79	13.80	13.82
Industrial	36.72	39.19	41.89	44.77	47.90	51.26	54.92	58.73	62.73	66.92	71.38	76.10
Commercial	25.04	26.70	28.50	30.42	32.51	34.75	37.18	39.71	42.36	45.14	48.09	51.21
Transport	1.27	1.32	1.36	1.41	1.47	1.52	1.58	1.64	1.70	1.76	1.82	1.89
Captive Generation	-0.32	-0.41	-0.52	-0.66	-0.84	-1.06	-1.35	-1.71	-2.18	-2.61	-3.08	-3.54

Note: Overall CAGR (2020–30): 5.3%

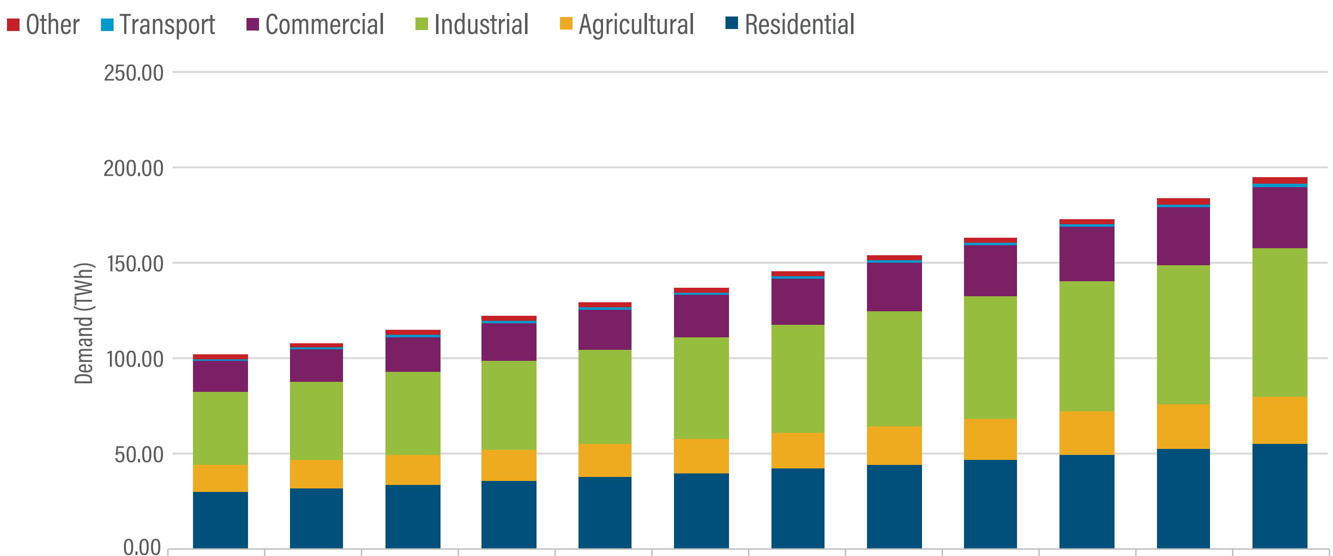
Source: Based on CEA 2019b.

We use the added forecasts to derive the annual growth rates for each sector until 2026–27. We then use five-year moving averages of the growth rates to estimate sectoral demand until 2030–31, which are similarly added together to obtain the total demand projections.

Similar to DD2, this scenario is not based on original projections but rather works with existing TANGEDCO projections. Therefore, the scenario cannot incorporate the impacts to demand from the pandemic and economic lockdown and may also overstate demand in the short run. This scenario is visualized in Figure 5. Overall demand grows at 6.1 percent each year to reach 194.7 TWh by 2030–31. Demand growth is distributed evenly across sectors.

The sector-wise breakdown of demand in 2030–31 across the three scenarios is summarized in Table 1. We see that residential demand retains a relatively higher share of overall demand in DD1 due to the depression of commercial and industrial activity during the COVID-19 lockdown period. Commercial activity is significantly higher in the CEA projections in DD2, whereas agriculture takes a much higher share in DD3. The distribution of demand has significant implications for distribution company revenues because C&I tariffs are higher and residential and agricultural electricity is subsidized. It is therefore likely that, setting aside costs, the revenues to TANGEDCO might be highest under DD2 and lowest under DD1.

Figure 5 | **Sectoral Demand Projections in DD3**



	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29	2029–30	2030–31
Residential	30.05	31.88	33.79	35.79	37.86	40.02	42.26	44.59	47.13	49.80	52.60	55.55
Agricultural	14.26	14.98	15.74	16.54	17.37	18.25	19.18	20.15	21.17	22.24	23.36	24.55
Industrial	38.49	41.09	43.82	46.72	49.80	53.08	56.57	60.27	64.24	68.46	72.96	77.75
Commercial	15.96	17.06	18.22	19.44	20.73	22.10	23.53	25.05	26.69	28.44	30.29	32.27
Transport	1.14	1.18	1.23	1.28	1.33	1.38	1.45	1.52	1.59	1.66	1.74	1.82
Other	2.05	2.11	2.17	2.23	2.29	2.36	2.43	2.50	2.57	2.65	2.72	2.80

Note: Overall CAGR (2020–30): 6.1%

Source: Based on TANGEDCO 2019b and the authors' assumptions.

Table 1 | **Sectoral Demand in Multiple Demand Scenarios, 2030–2031**

SECTOR	DD1: TARIFF ORDER NOTE AND COVID-19 IMPACTS (TWH)	DD2: CEA PROJECTIONS (TWH)	DD3: TANGEDCO CIP PROJECTIONS (TWH)
Transport	1.43	1.93	1.82
Commercial	33.73	53.27	32.27
Industrial	43.36	79.22	77.75
Agricultural	13.58	13.93	24.55
Residential	55.89	61.09	55.55
Other	0	(-3.54)	2.80
Overall	**147.99 (Net of T&D losses)**	**198.82**	**194.74**

Notes: CEA = Central Electricity Authority; CIP = capital investment plan; DD = demand scenario; T&D = transmission and distribution; TANGEDCO = Tamil Nadu Generation and Distribution Corporation.

Source: WRI analysis.

4. SUPPLY SCENARIOS

We develop four supply scenarios in total. Across scenarios, we assume that the PLF for a given generation source is constant. The PLF numbers for each generation source are as follows:

- Coal and lignite: 74.9 percent, in line with the average PLF for thermal generation in the 2017 Tariff Order Note
- Gas and diesel: 49.7 percent, in line with the average PLF for gas generation in the 2017 Tariff Order Note
- Nuclear: 57 percent, per Institute for Energy Economics and Financial Analysis (IEEFA) 2016–17 estimates (Buckley and Shah 2018)
- Biogas and biomass: 20 percent, per IEEFA 2016–17 estimates for renewables overall
- Hydro: 26.8 percent, in line with the average CUF in the 2017 Tariff Order Note
- Wind: 29.15 percent, in line with TNERC guidance (TNERC 2018)
- Solar: 19 percent, in line with TNERC guidance (TNERC 2019)

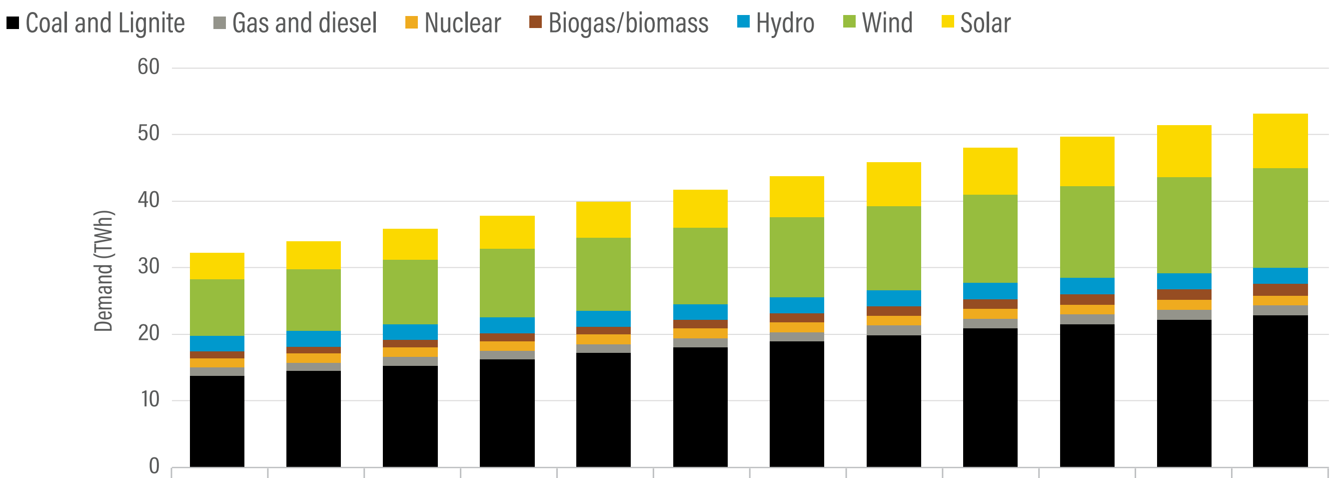
We take 2019–20 as the base year, and we obtain total capacity per source for that year from TEDA.[2] The scenarios are detailed below.

Supply Scenario 1: Curtailed Transition

Supply Scenario 1 (SS1) is built upon a range of assumptions that indicate a limited transition to renewables in the grid by 2030. We take modest capacity growth rates of 4–10 percent per year for solar and wind, assuming challenges with land acquisitions, import duties, a falling price of oil, and other policy and financial challenges (Kaveri 2019). The COVID-19 lockdown—together with its impacts on imports and labor—was also expected to affect renewable installations in 2020 (Pardikar 2020). We assume that units 3 and 4 of the Kundakulam nuclear plant do not come online and that there is a 0.5 GW addition to biomass capacity staggered through 2027 (Buckley and Shah 2018). We assume significant capacity additions to coal by 2027; in parallel, half of all end-of-life plants are extended, and all permitted new plants proceed, to reach 21 GW of capacity by 2027–28 and nearly 23 GW by 2030–31.

We assume T&D losses of 18.53 percent in 2030–31, assuming equivalence to the 2017–18 aggregate technical and commercial (AT&C) losses for TN (PFC India 2020). In this scenario, the total installed capacity reaches 53.12 GW, as shown in Figure 6. About 43 percent is wind and solar, and a roughly equal share comes from coal. Figure 7 shows the percentage breakup of this generation capacity in 2030–31.

Figure 6 | **Resource-Wise Installed Capacity Projections in SS1**



	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29	2029–30	2030–31
Coal and lignite	13.77	14.46	15.33	16.25	17.22	18.08	18.99	19.93	20.93	21.56	22.21	22.87
Gas and diesel	1.24	1.26	1.29	1.31	1.34	1.37	1.4	1.42	1.45	1.48	1.51	1.54
Nuclear	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
Biogas/biomass	0.98	1.02	1.08	1.13	1.19	1.25	1.31	1.37	1.44	1.51	1.59	1.67
Hydro	2.32	2.34	2.35	2.37	2.39	2.4	2.42	2.44	2.46	2.47	2.49	2.51
Wind	8.51	9.19	9.74	10.32	10.94	11.49	12.06	12.67	13.3	13.83	14.38	14.96
Solar	3.97	4.21	4.63	5	5.35	5.73	6.13	6.56	7.02	7.37	7.74	8.13

Source: WRI analysis.

Supply Scenario 2: Medium Transition

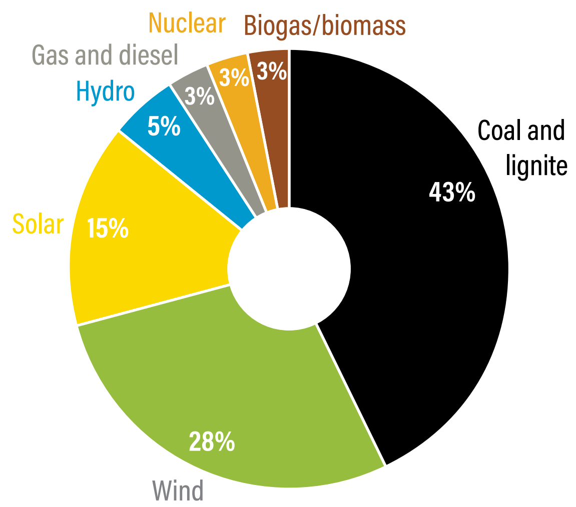
As shown in Figure 8, Supply Scenario 2 (SS2) assumes that installed solar capacity reaches 6 GW by 2023 and wind capacity reaches 15 GW by 2027, per IEEFA projections (Buckley and Shah 2018). Unit 3 of the Kundakulam nuclear power plant comes online, and coal reaches 17 GW by 2027, again based upon IEEFA projections. We assume T&D losses of about 16 percent in 2030–31, expecting annual 0.25 percent reductions from the 2017–18 AT&C losses. Total installed capacity reaches 55 GW, with about 52 percent coming from wind and solar.

Figure 9 shows the percentage breakdown of this generation capacity in 2030–31. Over half the installed capacity is wind and solar power.

Supply Scenario 3: Ambitious Transition

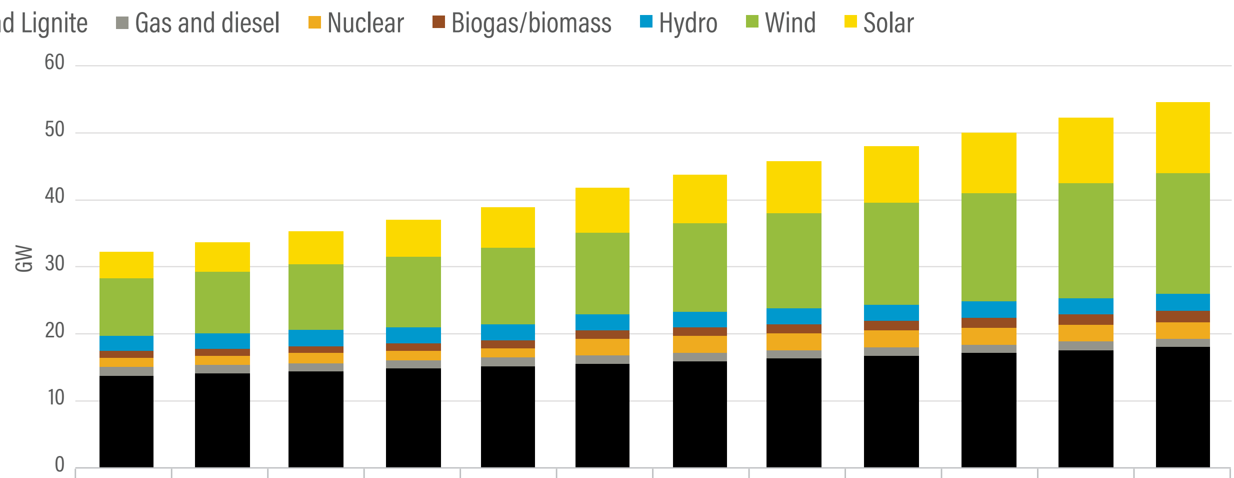
Supply Scenario 3 (SS3) assumes that solar reaches 9 GW by 2023–24, in line with TN's solar policy (TEDA 2019), and wind reaches nearly 25 GW by 2030–31 (InWEA n.d.). Hydro capacity increases by 1 GW in 2024 (Chaitanya 2019), Kundakulam nuclear units 3

Figure 7 | **Resource-Wise Share of Generation (2030-2031) in SS1**



Source: WRI analysis.

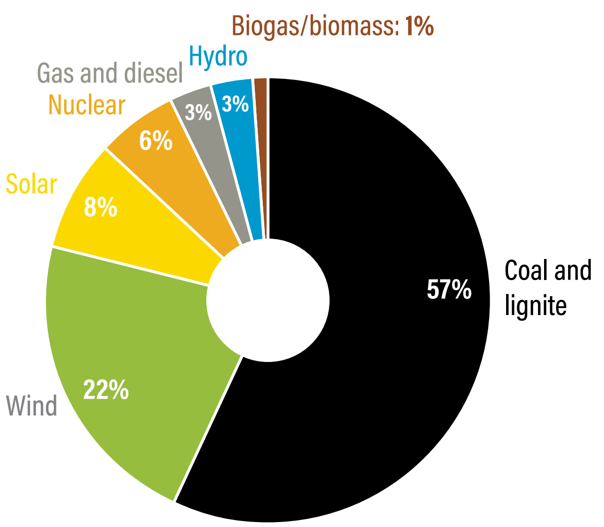
Figure 8 | **Resource-Wise Installed Capacity Projections in SS2**



	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29	2029–30	2030–31
Coal and lignite	13.77	14.11	14.47	14.83	15.2	15.58	15.97	16.37	16.78	17.2	17.63	18.07
Gas and diesel	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24
Nuclear	1.45	1.45	1.45	1.45	1.45	2.46	2.46	2.46	2.46	2.46	2.46	2.46
Biogas/biomass	0.98	1.02	1.08	1.13	1.19	1.25	1.31	1.37	1.44	1.51	1.59	1.67
Hydro	2.32	2.34	2.35	2.37	2.39	2.4	2.42	2.44	2.46	2.47	2.49	2.51
Wind	8.51	9.14	9.83	10.57	11.36	12.21	13.13	14.11	15.17	16.08	17.05	18.07
Solar	3.97	4.37	4.9	5.48	6.03	6.64	7.17	7.74	8.36	9.03	9.75	10.53

Source: WRI analysis.

Figure 9 | **Resource-Wise Share of Generation (2030–2031) in SS2**



Source: WRI analysis.

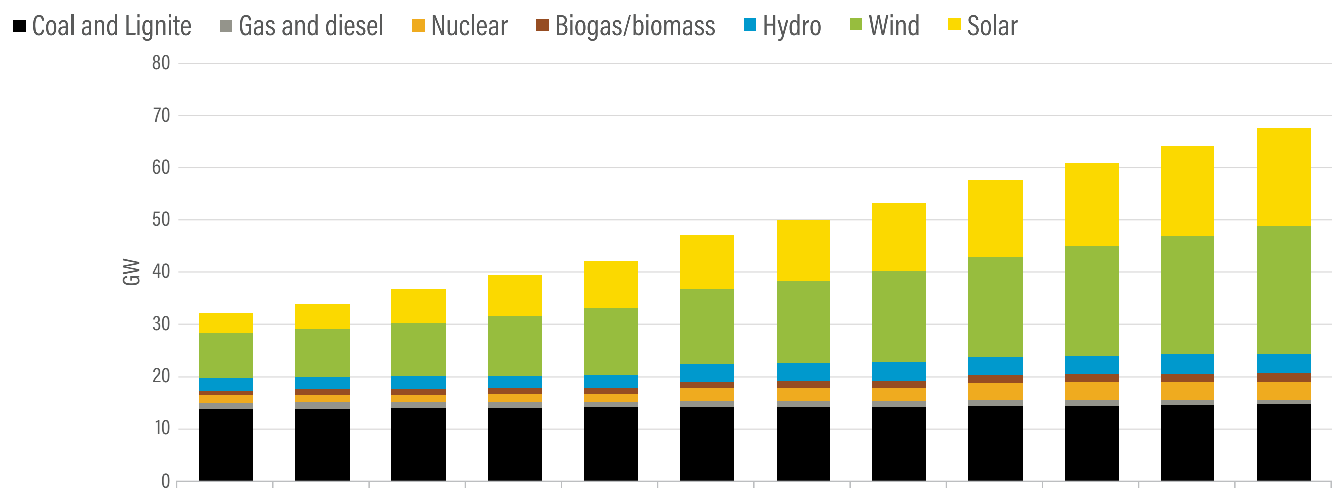
and 4 come online, and no new coal plants are commissioned except those under construction (Quint 2019). The T&D losses are assumed at 13 percent, factoring in annual 0.50 percent reductions from the 2017–18 AT&C losses. Total installed capacity reaches 67.8 GW, with about 64 percent of the share from wind and solar sources (Figure 10).

Figure 11 shows the percentage breakdown of this generation capacity in 2030–31. Over 60 percent of installed capacity comes from wind and solar power, with some increases in hydro and nuclear generation. Coal generation capacity remains stagnant overall.

Supply Scenario 4: Extending Historical Growth

Supply Scenario 4 (SS4) assumes an extension of historical growth rates, as shown in Figure 12. We use the four-year CAGR for solar capacity additions and eight-year CAGRs for all the other sources. We do this because the eight-year CAGR for solar is 130 percent per annum since virtually no solar capacity existed in 2011–12, and sustaining this in the future is unrealistic. We assume the same T&D losses as SS3:

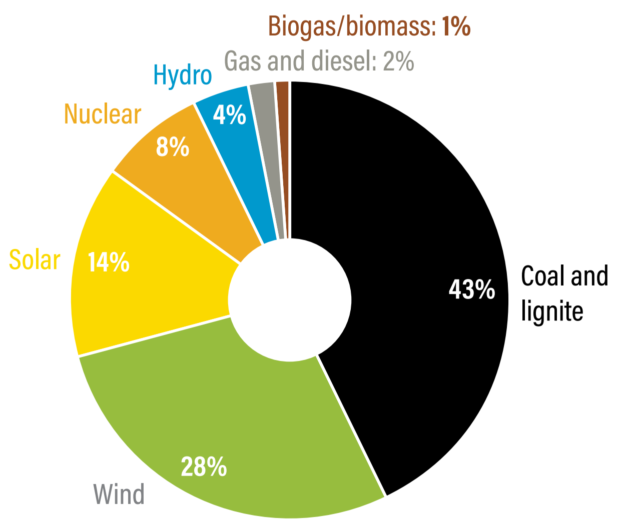
Figure 10 | **Resource-Wise Installed Capacity Projections in SS3**



	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29	2029–30	2030–31
Coal and lignite	13.77	13.91	13.98	14.05	14.12	14.19	14.26	14.33	14.4	14.47	14.55	14.62
Gas and diesel	1.24	1.21	1.19	1.17	1.14	1.12	1.1	1.08	1.05	1.03	1.01	0.99
Nuclear	1.45	1.45	1.45	1.45	1.45	2.46	2.46	2.46	3.45	3.45	3.45	3.45
Biogas/biomass	0.98	1.02	1.08	1.13	1.19	1.25	1.31	1.37	1.44	1.51	1.59	1.67
Hydro	2.32	2.35	2.37	2.39	2.42	3.43	3.47	3.5	3.54	3.57	3.61	3.64
Wind	8.51	9.14	10.24	11.47	12.85	14.39	15.83	17.41	19.15	21.07	22.75	24.57
Solar	3.97	4.93	6.31	7.82	8.99	10.34	11.58	12.98	14.53	15.84	17.27	18.82

Source: WRI analysis.

Figure 11 | **Resource-Wise Share of Generation (2030–2031) in SS3**



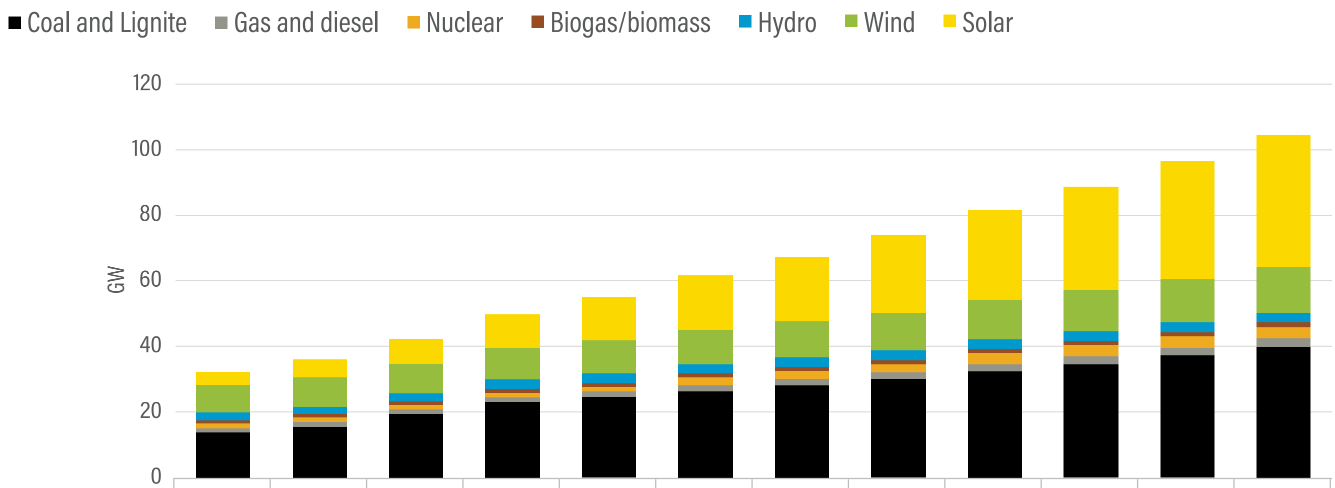
Source: WRI analysis.

13 percent. Total installed capacity in this scenario reaches 104.35 GW, with about 52 percent coming from wind and solar.

Figure 13 shows the percentage breakdown of this generation capacity in 2030–31. Half of the capacity comes from wind and solar. Despite the largest increases in capacity addition across scenarios, their share in the total capacity mix is moderated by significant increases in coal generation.

The overall supply mix in 2030–31 for the four scenarios is shown in Figure 14. Although the installed capacities of wind and solar power are the highest in SS4, their shares of total installed capacities are highest in SS3 because they are accompanied by a more ambitious phaseout of coal power plants. The total installed capacities of SS1 and SS2 are very similar; however, the share of renewables is higher in SS2.

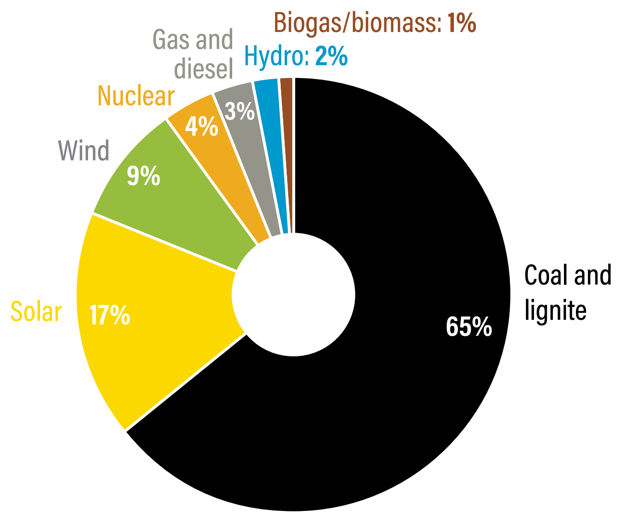
Figure 12 | **Resource-Wise Installed Capacity Projections in SS4**



	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29	2029–30	2030–31
Coal and lignite	13.77	15.55	19.3	22.93	24.56	26.31	28.18	30.19	32.34	34.64	37.11	39.75
Gas and diesel	1.24	1.33	1.42	1.52	1.63	1.75	1.87	2	2.15	2.3	2.46	2.64
Nuclear	1.45	1.45	1.45	1.45	1.45	2.46	2.46	2.46	3.45	3.45	3.45	3.45
Biogas/biomass	0.98	1.01	1.04	1.08	1.11	1.15	1.19	1.23	1.27	1.32	1.36	1.41
Hydro	2.32	2.34	2.36	2.89	2.91	2.94	2.96	2.98	3	3.02	3.04	3.07
Wind	8.51	8.88	9.28	9.69	10.12	10.57	11.04	11.53	12.05	12.58	13.14	13.72
Solar	3.97	5.43	7.41	10.12	13.15	16.44	19.73	23.67	27.22	31.3	36	40.32

Source: WRI analysis.

Figure 13 | **Resource-Wise Share of Generation (2030–2031) in SS4**



Source: WRI analysis.

5. KEY FINDINGS

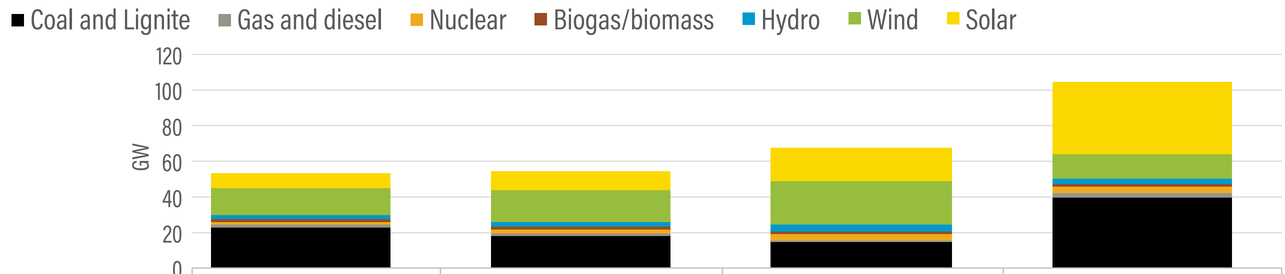
This section summarizes the key implications in terms of the state's energy balance and LCOE.

Implications for Energy Balance

In the four supply scenarios, we estimate the total potential generation in 2030 by multiplying the total installed capacity per source by the number of hours in a year: 8,760. We then multiply this by the respective PLF listed in Section 4 to calculate actual simulated generation and account for T&D losses to obtain the share of total demand in 2030 that is met by generation from this source. We compare total potential generation against the total demand from the 3 demand scenarios to obtain the 12 energy balance scenarios listed in Table 2.

In Table 2, positive numbers suggest that expected supply is larger than expected demand, whereas negative numbers identify expected shortages. We note that subject to constant PLFs, an ambitious energy transition (SS3) would help TANGEDCO come closest to balancing supply and demand in 2030–31 across

Figure 14 | **Summary of Resource-Wise Supply Mix, 2030-2031 for All Supply Scenarios**



	S1	S2	S3	S4
Coal and lignite	22.87	18.07	14.62	39.75
Gas and diesel	1.54	1.24	0.99	2.64
Nuclear	1.45	2.46	3.45	3.45
Biogas/biomass	1.67	1.67	1.67	1.41
Hydro	2.51	2.51	3.64	3.07
Wind	14.96	18.07	24.57	13.72
Solar	8.13	10.53	18.82	40.32

Source: WRI analysis.

Table 2 | **Energy Balance in 2030-31**

	SUPPLY SCENARIO 1: CURTAILED (182.93 TWH)	SUPPLY SCENARIO 2: MEDIUM (175.77 TWH)	SUPPLY SCENARIO 3: AMBITIOUS (193.93 TWH)	SUPPLY SCENARIO 4: HISTORICAL (349.02 TWH)
Demand Scenario 1 (147.9 TWh, net sales)	1.28	0.05	23.77	178.86
Demand Scenario 2 (198.8 TWh)	-15.89	-23.05	-4.89	150.20
Demand Scenario 3 (194.7 TWh)	-11.81	-18.97	-0.81	154.28

Note: Positive numbers indicate supply is greater than demand.

Source: WRI analysis.

demand scenarios. However, if we assume that future demand most closely tracks the DD1 scenario, which incorporates COVID-19 impacts, then a medium transition would come closest to balancing supply and demand in 2030–31. It should be noted that if the demand is uncertain and takes the DD3 trajectory rather than DD1, an ambitious transition could provide the most robust scenario for planners. These scenarios will guide utilities to conduct further in-depth analysis to identify which transition scenario would be the best fit for their specific situation.

The LCOE and Implications

The LCOE is a measure of the average net present cost of electricity generation for a generating plant over its lifetime. It is estimated as the ratio between the discounted costs over the lifetime of a power generation plant divided by a discounted sum of the actual energy generated. It represents the revenue per unit of electricity generated that would be required to recover the costs of building and operating a generation plant.

To calculate the LCOE, we assume a present cost of construction of solar and wind at ₹3,500 crore/MW and ₹4,500 crore/MW, respectively, with 2 percent

and 1 percent annual cost reductions until 2030–31, relying on The Energy and Resources Institute estimates (Pachouri et al. 2019). We further assume a weighted average cost of capital of 12 percent and a corporate tax rate of 33 percent. We then estimate the LCOE based on the following formula (EIA 2013):

$$\text{LCOE} = \frac{I - \sum_{t=1}^{T} d_t\, \gamma^t \times \alpha + \sum_{t=1}^{T} c_t\, \gamma^t \times (1-\alpha) - S\, \gamma^T}{\eta \sum_{t=1}^{T} \gamma^t \times x_t}$$

where

γ represents the time value of money [γ=1/(1+r)]

α is the corporate tax rate

η is the energy production

T is the life cycle of the project

dt, ct, and xt represent the depreciation schedule, operating cost, and system degradation in year t, respectively

This study assumes that revenue is fixed and PLF numbers are constant across the four supply scenarios. In 2030, the LCOE for solar and wind is projected to be ₹1.81/kWh and ₹1.77/kWh, respectively. This is significantly lower than current values, and points to the increasing cost efficiencies of RE, which should create positive feedback loops for the energy transition (Gupta 2019). Under constant assumptions about tax and depreciation rates and plant costs, the LCOE estimation is primarily influenced by an assumed decline in capital costs, which will be considerably lower in 2030–31 than they are today, and expected CUFs, which will be more than what they are today due to technology advancements, indicating an economic argument for investing in more renewables.

Sensitivity Checks

The 12 scenarios in this paper represent projections based on a combination of historical trends, assumptions about growth rates, efficiency numbers, and policy targets. It is therefore likely that the eventual electricity landscape in 2030–31 may differ from these scenarios due to varying supply and demand conditions, dynamic policy environment, and changing government priorities due to pandemic situations. To estimate what will be the impact of varying three key inputs on the final energy balances and LCOE, we have conducted this sensitivity analysis for one demand (DD1) and ambitious transition supply scenario (SS3), serving as an illustrative example.

Sensitivity Analysis 1: Impacts of greater energy efficiency savings on demand

Although the net sales in DD1 likely incorporate some efficiency improvements assuming a conservative estimate, the 2030–31 sectoral electricity demands in DD1 have been adjusted to explicitly reflect the efficiency improvements projected in the “moderate savings” scenario of the Bureau of Energy Efficiency report (BEE 2019). The original and adjusted sector demand (net of T&D losses) is shown in Table 3.

It can be observed that the total demand in 2030–31 is thus about 12.53 percent lower than it would otherwise be in the absence of these savings due to potential energy efficiency improvements identified sectorally. Table 4 compares these new demand numbers with

Table 3 | **Sector and Total Electricity Demands in DD1, 2030-2031**

SECTOR	ORIGINAL DEMAND (TWH)	SECTORAL SAVINGS DUE TO EE IMPROVEMENTS (%)	ADJUSTED DEMAND (TWH)
Transport	1.43	7	1.33
Commercial	33.73	17	28.00
Industrial	43.36	11	38.59
Agricultural	13.58	9	12.35
Residential	55.89	12	49.18
Total	**147.99**		**129.45**

Note: EE = energy efficiency.

Source: WRI analysis.

the four supply scenarios (leaving the capacity mix and PLFs unchanged), showing the original and adjusted energy balances.

Moderate efficiency improvements have the potential to create significant energy imbalances if supply-side planning does not account for these potential demand reductions. The LCOE for solar and wind power remains unchanged in this situation.

Sensitivity Analysis 2: Reductions in coal PLF on generation

Plans to increase renewable capacity in the state could potentially reduce the PLF of coal power plants. In line with permissible technical minimum limits, we have assumed the PLF is reduced to 55 percent in 2030, keeping the PLF of other sources unchanged. We evaluated the impacts of this change in coal PLF on generation from coal power plants and on total generation in SS3, as shown in Table 5.

Total generation—and the share of coal—declines significantly (up to 11.43 percent) with impacts on the energy balance, as shown in Table 6.

We have seen that a lower PLF for coal risks significant electricity supply shortfalls unless generation from other sources is ramped up to compensate. The LCOE for solar and wind power remains unchanged.

Sensitivity Analysis 3: Increases in solar and wind CUFs on generation

Solar and wind power CUFs are assumed to gradually increase to 32 percent and 36 percent by 2030–31, respectively. The impacts of this on solar and wind output and total generation in SS3 are shown in Table 7, assuming that the capacity mix and other PLFs are unchanged.

Total generation—and the share met by renewables—increases significantly in this scenario, up to 16.22 percent, and can more than offset the types of coal PLF reductions seen in Sensitivity Analysis 2 above. Impacts on the energy balance are shown in Table 8.

We observe that higher CUFs for solar and wind power in 2030 could potentially help reduce reliance on coal. In this case, the higher CUFs will also lead to significant reductions in the LCOE, as shown in Table 9, and will strengthen the economic case for shifting towards a cleaner pathway.

Table 4 | **Energy Surplus, 2030–2031**

SCENARIO	ORIGINAL (TWH)	ADJUSTED (TWH)
SS1	1.28	24.05
SS2	0.05	22.07
SS3	23.77	45.09
SS4	178.86	200.18

Note: SS = supply scenario.

Source: WRI analysis.

Table 5 | **Power Generation in SS3, 2030–2031**

GENERATION SOURCE	ORIGINAL (TWH)	ADJUSTED (TWH)
Coal	83.42	61.26
Total	193.93	171.77

Source: WRI analysis.

Table 6 | **Energy Surplus, 2030–2031 (TWh)**

SCENARIO	ORIGINAL (TWH)	ADJUSTED (TWH)
DD1	23.77	1.60
DD2	-4.89	-27.06
DD3	-0.81	-22.97

Note: DD = demand scenario.

Source: WRI analysis.

Table 7 | **Power Generation in SS3, 2030–2031**

GENERATION SOURCE	ORIGINAL (TWH)	ADJUSTED (TWH)
Solar	27.24	45.88
Wind	54.57	67.39
Total	193.93	225.39

Source: WRI analysis.

Table 8 | **Energy Surplus, 2030-2031**

SCENARIO	ORIGINAL (TWH)	ADJUSTED (TWH)
DD1	23.77	55.23
DD2	-4.89	26.57
DD3	-0.81	30.65

Note: DD = demand scenario.

Source: WRI analysis.

Table 9 | **Solar and Wind LCOE, 2030-2031**

TECHNOLOGY	ORIGINAL (₹/KWH)	ADJUSTED (₹/KWH)	FALL (%)
Solar	1.81	1.07	40.88
Wind	1.77	1.43	19.21

Source: WRI analysis.

Sensitivity analysis 4: Reductions in coal PLF to balance supply with demand

Lastly, we estimate how much the PLFs of coal-, gas-, and hydro-powered generation will have to change to balance energy demand and supply for SS3. In scenarios where the current PLF assumptions are expected to lead to excess supply, we assume that coal-powered generation is backed down first, until it reaches a floor PLF of 40 percent (CEA 2019a); gas- and hydro-powered generation are flexibilized subsequently, if needed, to achieve the balance. To address excess demand, hydro- and gas-powered generation are assumed to increase first, followed by coal-powered generation (CEA 2019a). The PLFs are shown in Table 10.

Policy Recommendations and Next Steps

The analysis of these 12 demand and supply scenario combinations offers various insights. In general, COVID-19 has significantly affected the electricity demand of the C&I sectors. TANGEDCO should account for such contingencies in its medium- and long-term plans. It should conduct annual demand forecasting exercises by looking at estimates and actual demand and making suitable corrections so that future projections are closer to the actual demand values. Utilities and planners should focus on designing multiple future scenarios along with estimating the RE-based capacity addition each year into the generation mix.

For instance, historical growth patterns are unlikely to be sustainable going forward since they will lead to a significant capacity surplus and will not be financially sustainable. It is therefore critical for the state to prudently plan the capacity additions.

The simulations show that achieving a balance between electricity demand and supply is more feasible under an ambitious energy transition scenario. This recommendation aligns with the 9 GW solar target set by the state for 2022–23. The state can plan for a high RE trajectory if demand is not on a conservative growth path. However, if the demand pattern continues to be constrained, TN should plan for a medium supply transition pathway.

Further, results indicate that the LCOE is mainly affected by changes to the PLF, given fixed assumptions on tax rates, depreciation rates, revenue, and plant costs. Utilities need to be on the lookout for new or disruptive technologies to account for changes in PLF. The LCOE for solar and wind were calculated to be ₹1.81/kWh and ₹1.77/kWh, respectively, in 2030–31, which are significantly lower than current levels. The LCOE measures the costs of producing electricity, from the cost of financing and building a power plant to lifetime operations and maintenance, decommissioning, and the cost of carbon emissions. However, this LCOE analysis may not point to the economic feasibility of technologies; the LCOE is not useful to compare the costs of technologies if nonmeasured costs differ significantly or if the technologies provide different services to the electricity system (Valeri 2019). This would require a detailed levelized cost of system analysis, which is beyond the scope of this paper.

Although the evacuation of RE, particularly wind energy, used to be a significant concern in previous years, with plans to build green corridor projects and with an interconnected grid, any excess RE generated could be exported to neighboring states. This may require robust transmission infrastructure and related favorable policies to export it to other states, which is beyond the scope of this paper. If the state adopts a high RE pathway, it should plan for integrating storage (utility-scale and behind-the-meter battery technologies and pumped hydro) to absorb RE generation (especially during daytime and monsoon periods) and avoid potential curtailments or spillage (Sundararagavan et al. 2021). Finally, with the current financial

Table 10 | **Coal and Hydro PLFs to Balance Energy Demand and Supply in 2030-2031**

	ORIGINAL			BALANCED		
	Coal PLF (%)	Hydro PLF (%)	Balance (TWh)	Coal PLF (%)	Hydro PLF (%)	Balance (TWh)
DD1 (147.9 TWh, net sales)	75	27	23.77	54	27	0.05
DD2 (198.8 TWh)	75	27	-4.89	75	45	0.02
DD3 (194.7 TWh)	75	27	-0.81	75	30	0.00

Note: DD = demand scenario; PLF = plant load factor.

Source: WRI analysis.

health of TANGEDCO and the delay in tariff revisions, TN should carefully plan for future power purchases, keeping possible demand growth scenarios in mind. Additional pumped storage plans, outlining future TN investments, have not been considered in this study because pumped storage will have a very small share in the overall energy mix and is a net electricity user. Detailed dispatch modeling exercises, and cost-benefit analyses, would help assess the size and duration of storage requirements to integrate current, new, and planned RE capacity additions in the state.

6. CONCLUSION

We rely upon existing forecasts and our own simulations to develop three demand and four supply scenarios for TN's electricity sector through 2030–31, broken down by sector and generating source. We use these 12 combinations to study the implications for the energy balance of the state and estimate the LCOE.

Such analyses can help stakeholders visualize how the state can plan in different supply and demand situations and provide a better understanding of the levers through which the LCOE can be reduced. It can aid TN in project-level planning and financial investment decisions and assist in the state's integrated resource planning processes, infrastructure planning, capital investment plans, budgets, and multiyear tariff orders.

Although the current demand scenarios are very uncertain due to the evolving impacts of COVID-19, the approach we follow is replicable across states and over time. Updates can also be integrated into our model, and it can be adapted for energy planning in other states as well as nationally.

ABBREVIATIONS

AT&C	aggregate technical and commercial
CAGR	compound annual growth rate
C&I	commercial and industrial
CEA	Central Electricity Authority
CIP	capital investment plan
CUF	capacity utilization factor
DD	demand scenario
FY	fiscal year
GSDP	gross state domestic product
IEEFA	Institute for Energy Economics and Financial Analysis
kWh	kilowatt-hour
LCOE	levelized cost of electricity
MNRE	Ministry of New and Renewable Energy
MU	million units
NREL	National Renewable Energy Laboratory
PLF	plant load factor
PM-KUSUM	Pradhan Mantri Kisan Urja Suraksha evam Utthan Mahabhiyan
RE	renewable energy
SLDC	State Load Despatch Centre
SRLDC	Southern Regional Load Despatch Centre
SS	supply scenario
TANGEDCO	Tamil Nadu Generation and Distribution Corporation
TANTRANSCO	Tamil Nadu Transmission Corporation
T&D	transmission and distribution
TEDA	Tamil Nadu Energy Development Agency
TN	Tamil Nadu
TNERC	Tamil Nadu Electricity Regulatory Commission
TWh	terawatt-hour

ENDNOTES

1. We arrive at these numbers in our simulations, based on the references consulted.

2. See the TEDA website, https://teda.in/.

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