Pathways for Tamil Nadu's Electric Power Sector: 2020 - 2030

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National Renewable Energy Laboratory

Tamil Nadu Generation and Distribution Corporation
Tamil Nadu Transmission Corporation Limited

NREL is a national laboratory of the U.S. Department of Energy
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Technical Report
NREL/TP-6A20-78266
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NOTICE

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Perspective

This report is part one of a two-part series that represents a year-long collaboration between the National Renewable Energy Laboratory (NREL) and the Tamil Nadu Generation and Distribution Corporation Limited (TANGEDCO) and Tamil Nadu Transmission Corporation Limited (TANTRANSCO) on power sector planning. This *Pathways for Tamil Nadu's Electric Power Sector 2020-2030* report outlines NREL's work with TANGEDCO's electricity sector planning department to develop a model of the state power system and evaluate multiple scenarios of system evolution, given resource constraints, costs of technologies, and power sector policies. A broad stakeholder group comprising TANGEDCO leadership, developers, regulators, and researchers from within the power sector community in Tamil Nadu helped to guide the main objectives of the study and provided technical feedback to the research team. The outcomes of this effort include multiple pathways for power sector growth to 2030 and a robust model of Tamil Nadu's power system that can be used to continually analyze the impact of new policies, regulations, or system changes. The second report in this series will build on the bulk system analysis by focusing on the rapidly transforming distribution network in the state. The report will outline a framework developed by NREL and TANGEDCO's distribution utility to quickly and accurately analyze the impacts of integrating renewable energy (RE) onto Tamil Nadu's distribution system. Together these studies help to prepare Tamil Nadu for a rapidly transforming power system.

NREL's partnership with TANGEDCO is the first of several collaborations with India's states to enhance their ability to plan for and effectively manage the transformation of India's power system to higher penetrations of RE. A better understanding of the impacts of this transition allows for better practices, more effective policies, and increased capacity to absorb new technologies. This work is supported by the Children's Investment Fund Foundation.

Acknowledgments

The authors are greatly indebted to several individuals for their thoughtful feedback and guidance, including Vikram Kapur (formerly CMD, TANGEDCO), S. Ravichandran (formerly Chief Engineer/Grid Operation, Tamil Nadu Load Dispatch Center), N. Balaji (Chief Engineer, Planning, TANGEDCO), D. Ravichandran (formerly Superintending Engineer, System Studies, TANGEDCO) and Shirish Sinha (Children's Investment Fund Foundation). We also thank the members of the System Studies group at TANGEDCO who contributed to inform the model design, input assumptions, and key scenarios. The study Transformation Advisory Committee comprised of representatives from National Institute of Wind Energy, Tamil Nadu Electricity Regulatory Commission, Indian Wind Power Association, Consumer and Civic Action Group, Auroville Consulting, World Resources Institute, and the Center for Study of Science, Technology, and Policy provided valuable feedback and review of the study results. And thank you to Deepak Krishnan, Naren Pasupalati, and Sanhya Sundaragavan (World Resources Institute) along with K. V. Karikrishna (Center for Study of Science, Technology, and Policy) and Kelly Eurek and Stuart Cohen (NREL) for their reviews. Any errors and omissions are solely the responsibility of the authors. This work was funded by the Children's Investment Fund Foundation.

List of Acronyms

BA	balancing area
BESS	battery energy storage system
CCGT	combined cycle gas turbine
DUPV	distributed photovoltaic
INR	Indian rupee
LNG	liquified natural gas
NREL	National Renewable Energy Laboratory
PV	photovoltaic
RE	renewable energy
ReEDS	Regional Energy Deployment System
TANGEDCO	Tamil Nadu Generation and Distribution Corporation Limited
TANTRANSCO	Tamil Nadu Transmission Corporation Limited
UPV	utility photovoltaic
VOM	variable operation and maintenance
VRE	variable renewable energy
WHR	waste heat recovery

Executive Summary

Tamil Nadu is at the forefront of India's renewable energy (RE) transformation. The state has long been a leader in wind energy, accounting for 25% of India's wind capacity, and has a target to deploy 9 GW of solar photovoltaic (PV) capacity by 2023.The emerging challenge for Tamil Nadu's power system planners is determining how to shape the trajectory of the state's power system with increasing penetrations of RE, considering the confluence of technology, cost, and policy factors.

The objective of this study is to evaluate least-cost pathways for Tamil Nadu's electric power system over 2020–2030. The data collection and model design processes undertaken for this study provide a framework for recurring planning studies. This study finds that anticipated changes in electricity demand and component costs can drive a significant shift in Tamil Nadu's future electricity supply and how this system will be operated.

Tamil Nadu's electric power system is poised to shift from a thermal-based system to a renewable-based system.

Anticipated changes in component costs make investments in wind, solar PV, and battery storage increasingly competitive with thermal capacity. In the Base scenario, under existing projections for technology costs, electricity demand, and fuel availability, investments in wind and solar are economically deployed beyond state-level targets. The RE capacity increases from 14 GW in 2020 to 34 GW in 2030. The share of generation from wind and solar reaches 52% by 2030. Investments in battery storage are economic as early as 2025 due to projected decreases in capital costs and increasing deployment of wind and solar, which are complemented by battery storage's ability to shift energy from high-RE periods to high-load periods (Figure ES- 1).

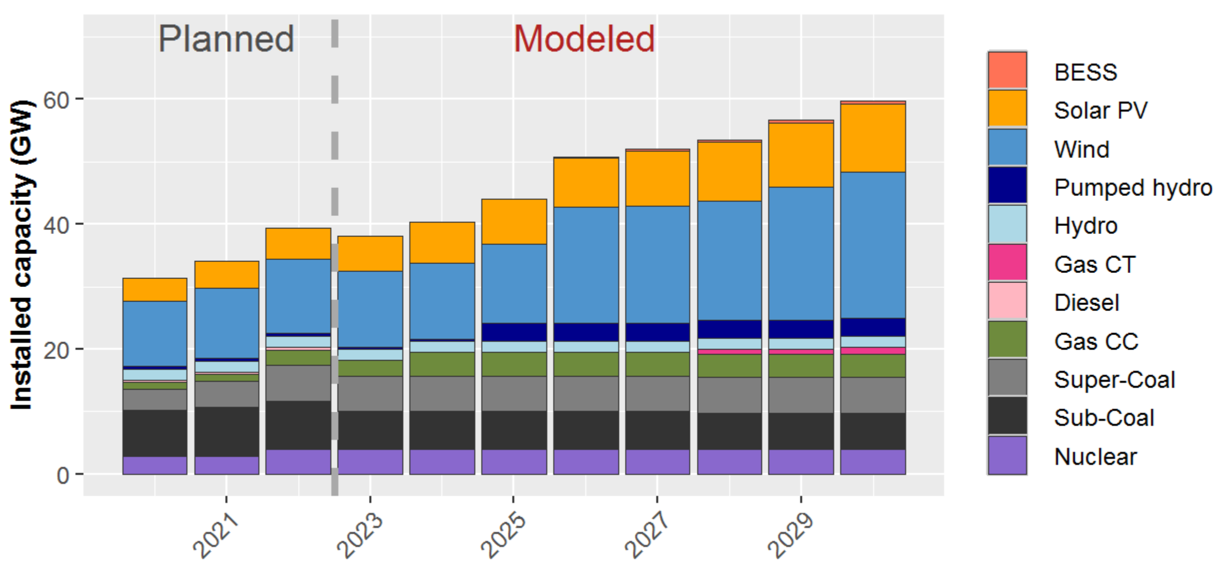

Figure ES- 1. Total installed capacity, 2020–2030 in the Base scenario

Note: For all technologies except wind and solar, we assume projects not already underway will not be complete by 2023; therefore, the first year when new capacity can be added based on economic criteria is 2023.

Investments in new capacity are increasingly driven by coincidence of RE and demand rather than annual peak demand alone.

In a future system with high penetrations of RE, capacity additions are driven by the coincidence of demand and RE generation rather than peak demand alone. This study finds the system could have surplus capacity during the peak demand months of July through September because this period corresponds to periods in which more wind generation is available to meet peak demand. By contrast, moderate demand period of January–March experiences the lowest margin of surplus capacity due to lower wind availability.

Investments in wind capacity may be economic beyond current 2030 ambitions.

Although 2030 RE targets have not been set, consultations with a broad stakeholder group of power system experts from across the state identified Tamil Nadu's RE targets could reach 11 GW of solar PV and 13 GW of wind by 2030. The study finds wind investments are economic beyond this target, reaching 23 GW by 2030. Investments in solar PV are driven by the potential 2030 statewide capacity target, indicating this level investment would not otherwise occur.

Targeted policies to reduce the cost of solar PV could achieve the same level of RE investments as imposing higher 2030 RE capacity targets.

Sensitivity tests compare the impact of two alternative approaches to increase the deployment of RE in the future power system: reducing technology costs for solar PV and increasing proposed statewide RE capacity targets. Both strategies achieve similar levels of RE investment by 2030 (Figure ES- 2). Solar PV capacity reaches 16 GW in the Low Solar Cost scenario and 18.6 GW in the High RE Target scenario. Wind capacity reaches 19 GW and 22 GW in the Low Solar Cost and High RE Target scenarios, respectively.

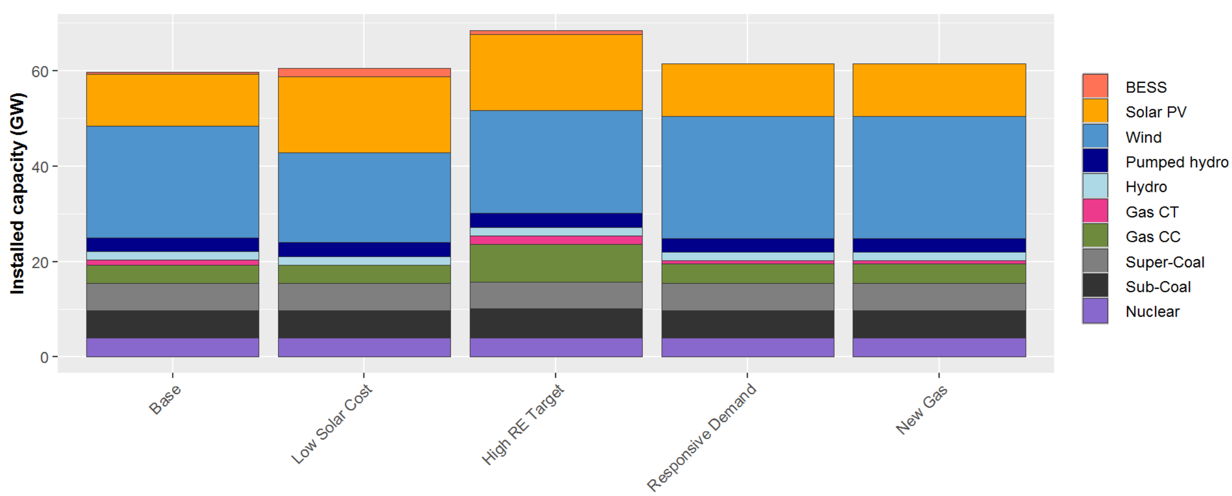

Figure ES- 2. Comparison of 2030 installed capacity for all scenarios

Energy storage technologies help balance supply and demand during peak demand periods.

Investments in battery storage begin in 2025, reaching 410 MW by 2030 in the Base scenario. As the penetration of RE increases, there is an increased role for energy storage technologies to time-shift excess generation from daytime hours to evening peak hours (Figure ES- 3). Using storage technologies as a peaking resource avoids the needs for new generation capacity to meet peak demand and improves the economics for solar PV that is not available to meet electricity demand in the evenings.

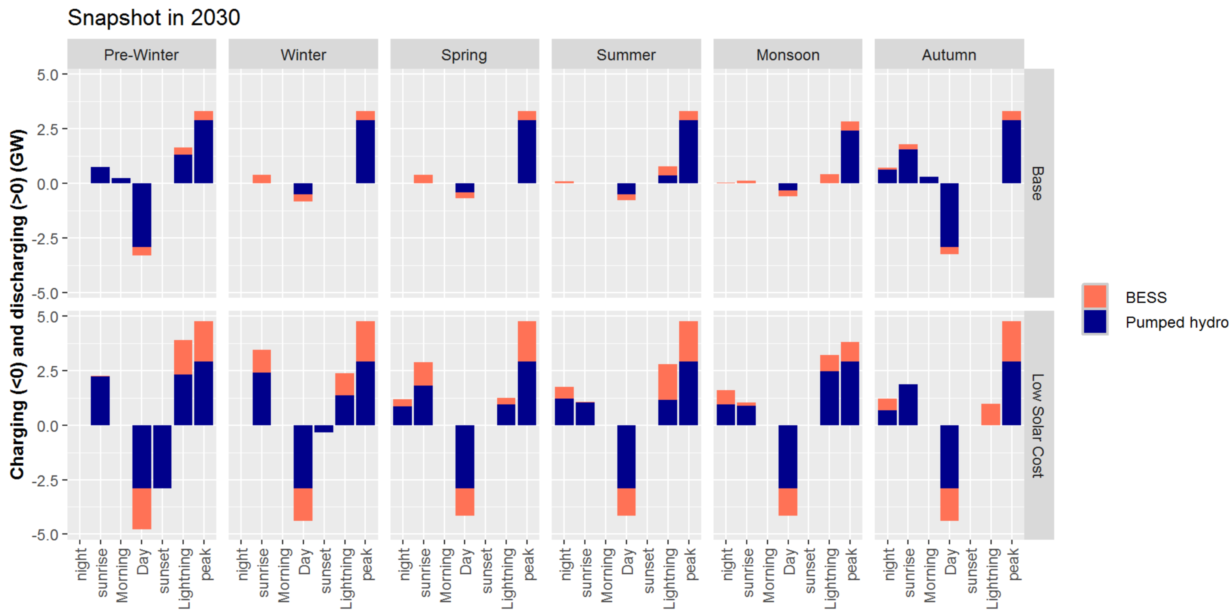

Figure ES- 3. Increased solar PV capacity in the Low-Cost Solar scenario increases the role of energy storage to time-shift excess generation, 2030

Demand response reduces the need for flexible resources.

Policy or regulatory measures to shift consumption during peak demand to other times of day could reduce the need for investments in flexible resources and favor technologies that are available throughout the day. Investments in 4-hour duration battery storage decrease from 410 MW to 74 MW by 2030 in scenarios where 2030 peak demand is 10% lower than in the Base scenario. Less intraday variation in electricity demand results in increased investments in wind (400 MW) and increased generation from existing nuclear, coal, and wind technologies by 2030.

Investments in natural gas-fired capacity are not limited by fuel availability.

Scenario tests of increased gas availability to the power sector have no significant impact on investments or system operations. By 2030, over 88% of gas fuel available for electricity generation remain unused. In all model scenarios, both existing and new gas technologies in Tamil Nadu are used for resource adequacy purposes only. While we do not model the range of contingencies in which this capacity may be dispatched, the utilization factor may remain low. This indicates the future share of gas in electricity production is limited by cost-competitiveness with other technologies rather than fuel availability.

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1 Introduction

Tamil Nadu's electric power system has the potential for rapid transformation. Visionary government targets, combined with rapid changes in technology costs and performance, are transforming the portfolio of supply options system planners can consider to meet growing demand. The Government of India has a target of deploying 175 GW from wind, solar, biomass, and small hydropower by 2022 and 40% of electricity capacity from nonfossil fuel sources by 2030 (UNFCCC 2015). Recent announcements have indicated more ambitious renewable energy (RE) targets for 2030 (Press Trust of India 2019). Tamil Nadu will play a central role in achieving the country's RE goals. The state has long been a leader in wind energy, having established wind farms as early as 1995, and it currently accounts for 25% of India's wind capacity (MNRE 2020; TEDA 2020). Tamil Nadu is now poised to become a leader in solar energy as well, following a recent policy target to deploy 9 GW of solar photovoltaic (PV) by 2023 (TEDA 2019).

Increased deployment of variable renewable energy (VRE) raises new questions for system planners regarding the optimal siting of generation capacity, trade-offs between generation and transmission investments, and system flexibility needs. Power system infrastructure is expensive and long-lived; it is therefore important to evaluate planning decisions in the future in which those assets will operate. As an early adopter of wind and solar, Tamil Nadu is experienced in integrating VRE into daily power system operations. The emerging challenge for Tamil Nadu's planners is how to shape the trajectory of the state's power system with increasing penetrations of VRE while considering the confluence of technology, cost, and policy factors as well as interaction with the rest of the country. The objective of this study is to evaluate least-cost pathways for Tamil Nadu's electric power system over the period of 2020–2030. Long-term planning studies, such as this one, are relevant for a range of power sector stakeholders including policymakers, utilities, project developers, consumer groups, and financing institutions to ensure the sector has an enabling policy, regulatory, and technical environment to achieve its goals.

This study is enabled through a state-of-the-art modeling tool developed by the National Renewable Energy Laboratory (NREL) with support from the U.S. Department of Energy, the Hewlett Foundation, and the Children's Investment Fund Foundation. The model structure developed for this study can be applied to other systems to effectively characterize VRE in long-term planning decisions.

This report begins with a description of the methodology used for the study in Section 2, followed by the model inputs and assumptions in Sections 3–6. The study results are presented in Section 7, and Section 8 concludes with a summary of key takeaways and future work.

1.1 Study Objectives

This study analyzes the investments and operational needs of Tamil Nadu's generation and transmission systems to meet anticipated system requirements from 2020 to 2030 at least cost. These system requirements include demand for energy, firm capacity, and operating reserves, as well as policy and regulatory mandates. The primary analysis tool is NREL's Regional Energy Deployment System (ReEDS) model. ReEDS explicitly addresses challenges associated with grid integration of VRE technologies through detailed temporal and geospatial representation of VRE resources.

Though ReEDS can be used to address a broad range of planning questions, it does not cover the full spectrum of issues associated with power system planning. Specifically, the model does not feature:

- Production cost modeling of hourly or subhourly dispatch decisions
- Optimal power flow of the nodal bulk transmission system
- Contingency analysis
- Market structure and tariff design
- Noneconomic (e.g., behavioral, social, or institutional) factors that impact investment and dispatch decisions.

The study provides insight into how the power sector may evolve and the key drivers behind this evolution by investigating the impact of different factors (e.g., technology costs, fuel availability, demand growth, and policy targets) on generation and transmission capacity investments in Tamil Nadu. The relevant trends and range of possible futures will continue to evolve, prompting the need for ongoing refinement of the underlying data inputs and model scenarios. The data collection and model design processes undertaken for the study provide a framework for recurring planning studies.

2 Planning Methodology

The primary tool for this analysis is a capacity expansion model that identifies the least-cost mix of generation and transmission technologies required to meet future system needs. We use scenario analysis to address uncertainty in future technology costs, fuel availability, electricity demand, and policies.

2.1 Modeling Framework

Capacity expansion models must balance the need for detailed representation of the electricity sector with computational complexity. Planning tools vary significantly in their treatment of operating constraints, energy prices, and demand projections, as well as temporal and geographic resolution. For systems such as that of Tamil Nadu, where VRE technologies may play an increasing role in the future generation mix, the appropriate tool should capture the diversity of candidate VRE technologies and their applications, the location-dependent quality of these resources, and inherent uncertainty and variability in wind and solar generation.

We selected the ReEDS[1] capacity expansion model for this study for its rich assessment of technical, geographic, and operational aspects of VRE deployment. At its core, ReEDS employs linear optimization to minimize the net present value of electricity system investment and operating costs subject to several constraints. The major constraints include balancing electricity supply and demand, resource supply limits, planning and operating reserve constraints, transmission constraints, and policy targets. These constraints are met by considering a broad portfolio of generation, storage, and transmission technologies. More information on ReEDS can be found in Brown et al. (2020). The model is implemented in the General Algebraic Modeling System programming language. A publicly available version of the ReEDS model developed for national-level planning in India can be accessed from https://www.nrel.gov/analysis/reeds/.

2.2 Study Scenarios

The study considers five scenarios outlined in Table 1. The Base scenario represents a business-as-usual case, in which trends in cost and operations remain relatively constant in the future. All subsequent scenarios change a single assumption from the Base. Details about the input values for each scenario are presented in the following Sections 3 and 4.

[1] For more information, see "Regional Energy Deployment System Model," NREL, https://www.nrel.gov/analysis/reeds/.

Table 1. Model Scenarios

Scenario	Description
Base	• Technology cost projections based on NREL's 2018 Annual Technology Baseline "Mid" cost estimates • State RE targets: 9 GW solar PV and 11 GW wind by 2022,[2] 11 GW solar PV and 13 GW wind by 2030[3] • Demand growth are based on 19th Electric Power Survey (CEA 2018a) and TANGEDCO region wise forecasts • Gas availability based on CEA (2019)
Low Solar Cost	Solar PV capital costs decline 50% more rapidly than in the Base scenario
High RE Target	2030 state RE targets increase to 18.6 GW solar PV and 20 GW wind
Responsive Demand	10% reduction in peak demand shifted to off-peak periods
New Gas	Gas availability for electricity generation increases in future years

For all scenarios, we assume perfect foresight[4]; that is, investment and operating decisions are made assuming perfect knowledge about how technology costs and performance and electricity demand will change over time. However, we do account for supply and demand uncertainty by including planning reserve margins and the requirement to procure operating reserves, which helps to ensure the final capacity is sufficient to serve load if it varies from the predicted demand.

[2] https://niti.gov.in/writereaddata/files/175-GW-Renewable-Energy.pdf
[3] While no official 2030 target currently exists, this target was established through stakeholder consultations.
[4] ReEDS also has the capability to run with limited or no foresight.

3 Model Regions

As part of the interconnected Indian power grid, planning and operating decisions in Tamil Nadu impact and are impacted by the rest of the country. To capture these interactions, the capacity expansion model includes the entire Indian grid, with Tamil Nadu represented in greater detail than other states and union territories.

The model includes three levels of spatial resolution: operating regions, balancing areas (BAs), and resource regions. The five operating regions of India include the Northern (NR), Northeastern, Eastern (NER), Southern (SR), and Western (WR) regions. Each operating region is composed of BAs representing states and union territories that are connected by the transmission network. Tamil Nadu is further divided into nine BAs, one for each of the state's operating zones. Finally, within each BA there are multiple resource regions designed to capture differences in RE resources at a higher level of granularity. In Tamil Nadu, 32 resource regions represent each district. Figure 1 and Figure 2 show the division into regions, BAs, and resource regions for India and Tamil Nadu, respectively.

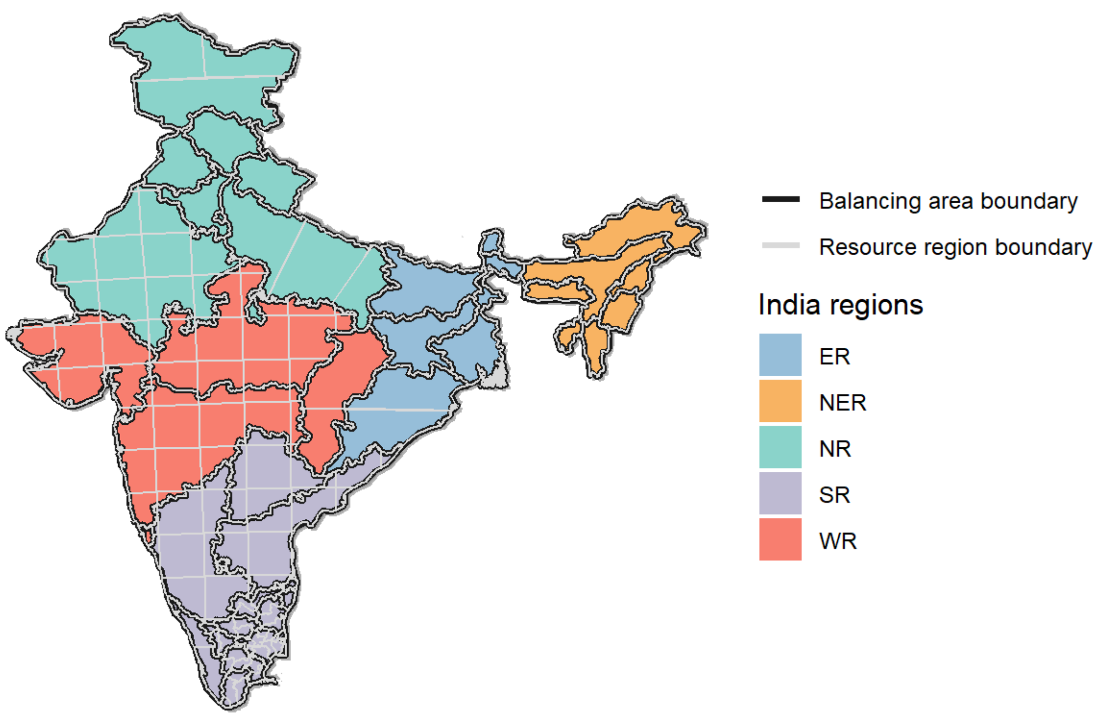

Figure 1. Region, BAs, and resource regions in India

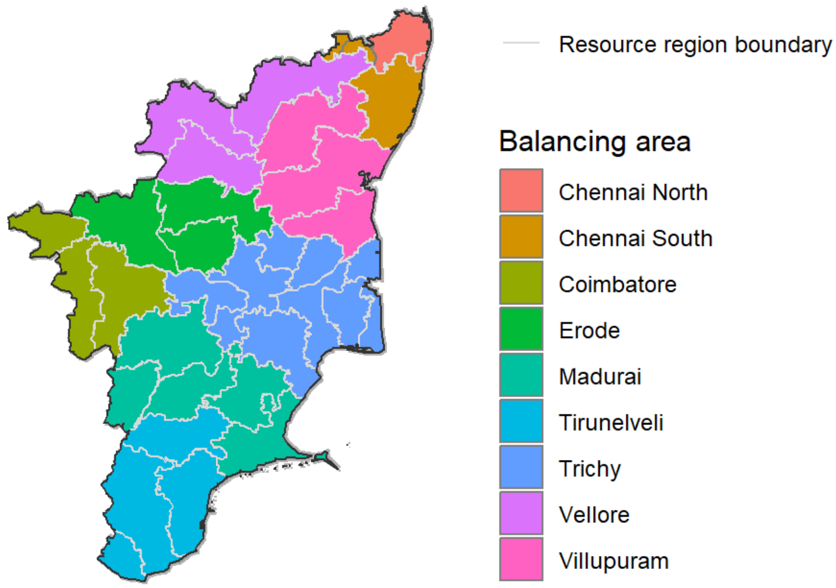

Figure 2. Tamil Nadu model BAs and resource regions

4 Electricity Demand

Tamil Nadu is expecting large changes in both the total amount of electricity demand and the daily patterns of demand over the modeled time period. This section outlines the assumptions for demand growth and the approach to translate hourly demand data into a series of time-slices or representative hours.

4.1 Electricity Demand Forecast

The 2020–2030 demand forecast combines region wise data on actual and forecast demand growth with statewide growth estimates from the 19th Electric Power Survey (CEA 2018a). The Tamil Nadu Generation and Distribution Corporation Limited (TANGEDCO) provided actual and forecast annual energy and peak demand data for each operating region over the period of 2020–2022. After 2023, only statewide forecasts are available. For the period of 2023–2030, we assume demand growth in each BA converges to the statewide average growth rate of 5.7%. Table 2 contains the annual energy and peak demand growth assumptions for each BA.

Table 2. Assumed Growth in Electricity Demand, 2020–2030

BA	Annual Energy (TWh)			Peak Demand (GW)		
	2020	2030	Average Annual Growth (%)	2020	2030	Average Annual Growth (%)
Chennai North	11.4	16.4	3.7	1.7	2.5	4.0
Chennai South	14.3	20.5	3.7	2.1	3.1	4.0
Coimbatore	18.8	31.2	5.2	2.8	4.8	5.6
Erode	15.2	27.1	6.0	2.2	4.1	6.3
Madurai	14.0	18.3	2.7	2.1	2.8	3.1
Tirunelveli	10.0	17.2	5.5	1.5	2.6	5.9
Trichy	14.1	25.2	6.0	2.1	3.8	6.4
Vellore	13.4	25.8	6.8	2.0	3.9	7.1
Villupuram	12.5	20.7	5.2	1.9	3.2	5.5
Tamil Nadu	**123.7**	**202.3**	**5.0**	**18.3**	**30.8**	**5.4**

To capture changes in the load shape, we use the statewide 2020 hourly demand profile from Palchak et al. (2017) as the base year for the load forecast. This statewide load data is disaggregated into region wise hourly profiles based on each region's contribution to total annual energy in 2020 (Table 2). The hourly values are then increased based on anticipated growth in annual energy and peak demand. We designate the top 40 demand hours in each month as "peak" hours and increase the load during these hours based on the forecast peak demand growth. For all other hours, we increase the load until the total annual demand matches the forecast growth in annual demand. Figure 3 shows the change in average load profiles for Tamil Nadu for select months.

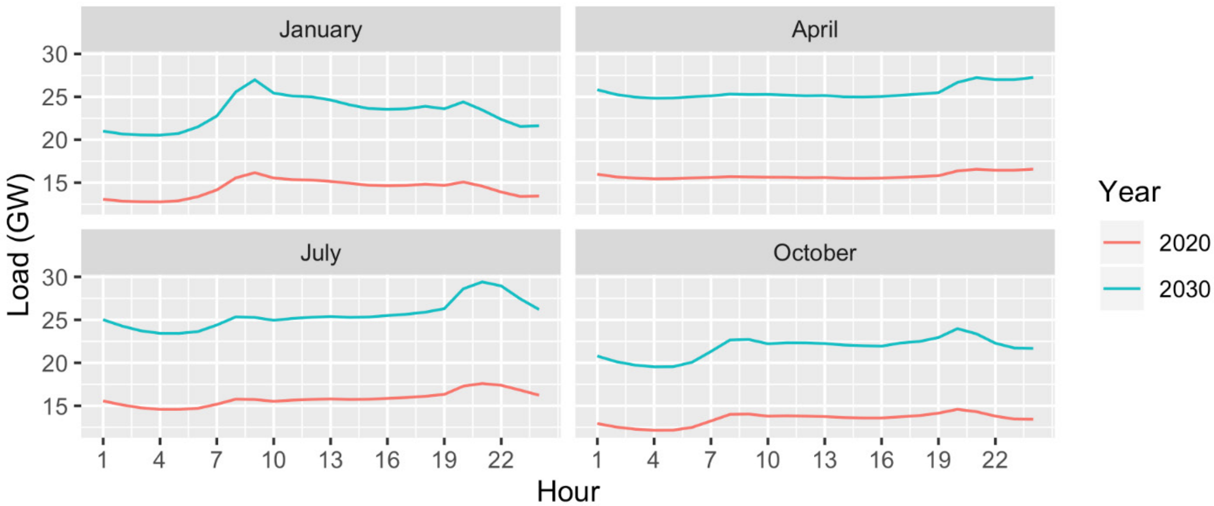

Figure 3. Average daily load profile for select months, 2020 and 2030

The **Responsive Demand scenario** investigates the impact of potential demand response programs that result in time-shifting of load from peak demand hours to other times of day. In this scenario, we assume peak demand is reduced by 10%, and the reduced energy is spread across other nonpeak time-slices. This scenario does not investigate the impact of specific programs or policies or seek to determine the optimal level of demand shifting. These could be areas for future work.

4.2 Time-Slices

Annual demand is represented with 42 time-slices designed to capture changes in seasonal and daily demand patterns, as well as wind and solar availability. The time-slices include six seasons (Pre-Winter, Winter, Spring, Summer, Monsoon, and Autumn) with seven representative times of day per season (Night, Sunrise, Morning, Day Peak, Sunset, Lighting Peak, Peak). Table 3 shows how the demand in each hour is allocated to a particular time-slice. Each time-slice provides a representation of the typical electricity demand that occurs within the respective period (e.g., the Winter Night time-slice represents average electricity demand between 23:00 and 5:00 from mid-January to mid-March).

Table 3. Mapping Hourly Electricity Demand into 42 Time-Slices

<table>
<tr><th></th><th>Winter</th><th>Spring</th><th>Summer</th><th>Monsoon</th><th>Autumn</th><th>Pre-Winter</th></tr>
<tr><th></th><th>16 Jan – 15 March</th><th>16 March – 15 May</th><th>16 May – 15 July</th><th>16 July – 15 Sept</th><th>16 Sept– 15 Nov</th><th>16 Nov – 15 Jan</th></tr>
<tr><td>1</td><td rowspan="5">Night</td><td rowspan="4">Night</td><td rowspan="4">Night</td><td rowspan="4">Night</td><td rowspan="4">Night</td><td rowspan="5">Night</td></tr>
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<tr><td>4</td></tr>
<tr><td>5</td><td rowspan="3">Sunrise</td><td rowspan="3">Sunrise</td><td rowspan="3">Sunrise</td><td rowspan="3">Sunrise</td></tr>
<tr><td>6</td><td rowspan="3">Sunrise</td><td rowspan="3">Sunrise</td></tr>
<tr><td>7</td></tr>
<tr><td>8</td><td rowspan="4">Morning</td><td rowspan="4">Morning</td><td rowspan="4">Morning</td><td rowspan="4">Morning</td></tr>
<tr><td>9</td><td rowspan="3">Morning</td><td rowspan="3">Morning</td></tr>
<tr><td>10</td></tr>
<tr><td>11</td></tr>
<tr><td>12</td><td rowspan="4">Day Peak</td><td rowspan="6">Day Peak</td><td rowspan="6">Day Peak</td><td rowspan="6">Day Peak</td><td rowspan="5">Day Peak</td><td rowspan="4">Day Peak</td></tr>
<tr><td>13</td></tr>
<tr><td>14</td></tr>
<tr><td>15</td></tr>
<tr><td>16</td><td rowspan="3">Sunset</td><td rowspan="3">Sunset</td></tr>
<tr><td>17</td><td rowspan="3">Sunset</td></tr>
<tr><td>18</td><td rowspan="3">Sunset</td><td rowspan="3">Sunset</td><td rowspan="3">Sunset</td></tr>
<tr><td>19</td><td rowspan="4">Lighting Peak</td><td rowspan="4">Lighting Peak</td></tr>
<tr><td>20</td><td rowspan="3">Lighting Peak</td></tr>
<tr><td>21</td><td rowspan="2">Lighting Peak</td><td rowspan="2">Lighting Peak</td><td rowspan="2">Lighting Peak</td></tr>
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<tr><td>24</td></tr>
</table>

Sunrise and sunset periods are determined based on solar generation profiles from Palchak et al. (2017). They represent the first and last 3 hours of the day when solar generation is available, respectively. Peak period time-slices are not depicted in Table 3 because the peak hours vary by region and season. Periods of seasonal peak load for each region are determined based on the highest 40 region-wise demand hours. After every hour of the year is allocated to one of the 42 time-slices, the time-slice load is calculated as the mean load from all hours assigned to that time-slice.

Text Box 1. How Well Do Time-Slices Approximate Load and RE Resources?

The model time-slices are designed to capture the major seasonal and diurnal trends in load and wind and solar resources needed for resource adequacy planning while maintaining a manageable number of decision variables. We validated the time-slices against hourly data to identify potential approximation errors. Figure 4 compares load duration curves for actual hourly and approximate (time-slice) load.

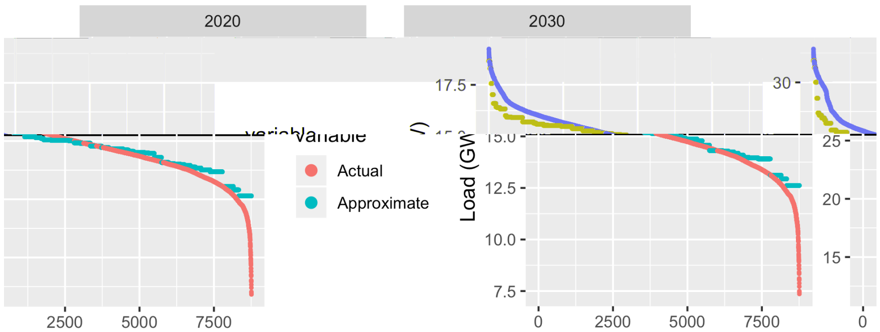

Figure 4. Comparison of actual and approximate load duration curves, 2017 and 2030

The time-slice approximation tends to underestimate periods with very high load and overestimate periods of very low load. System planners concerned about resource adequacy are most concerned about high-load periods. In both 2020 and 2030, the time-slice approximation underestimates peak load by 3%, which is equivalent to 0.6 GW and 1 GW, respectively. This underestimation is the result of averaging the top 40 hours of demand in each season rather than using a single highest demand hour. The normalized root mean square error between the actual and approximate load is 10%.

For RE resources, the time-slice approximation underestimates periods of both very high wind and very high solar availability, which may result in an underestimate of RE curtailment. The normalized root mean square error for wind and solar are 12% and 10%, respectively. For wind, the time-slice approximation tends to underestimate wind resources during the high wind months of June and July (Figure 5). Approximation errors for solar follow a daily pattern where the time-slices overestimate solar resources during the morning and early evening hours and underestimate solar resources during the middle of the day (Figure 5).

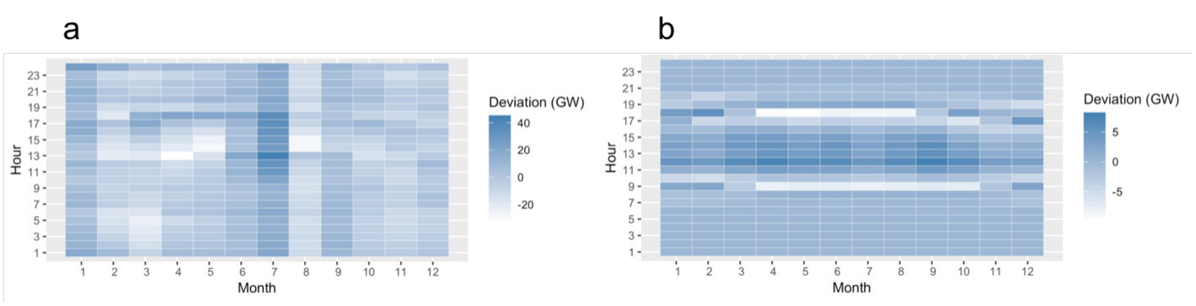

Figure 5. Patterns of approximation errors in potential (a) wind and (b) solar generation

Values <0 denote overestimate; values >0 denote underestimate.

5 Electricity Supply

The generation fleet is represented by several different technology types, each with its own techno-economic parameters. Table 4 summarizes the generation technologies considered in the model.

Table 4. Generation Technology Candidates

Thermal	Renewable	Storage (duration)
Combined-cycle gas turbine (CCGT) Gas	Distributed PV (DUPV)	Batter Energy Storage Systems (BESS) (4-hour) [a]
CCGT liquefied natural gas (LNG)	Hydro pondage	Hydro pumped (12-hour)
Combustion turbine (CT) gas	Hydro run-of-river	
Cogeneration bagasse	Hydro storage (reservoir)	
Diesel	Land-based wind [b]	
Nuclear	Utility PV (UPV)	
Subcritical coal		
Subcritical lignite		
Supercritical coal		
Waste heat recovery (WHR)		

[a] BESSs are considered grid-connected, grid-scale energy storage assets that are independently operated and can be independently sited or co-located with RE or conventional power plants. Potential cost savings from shared equipment in tightly coupled RE and BESS projects are not considered in this study.

[b] Offshore wind is not included as a candidate because of insufficient data about resource and technical potential.

Simplifications are made in the representation of generation units to maintain a tractable optimization problem. Here we aggregate all units of the same technology within a BA, with the exception of wind and solar, which are aggregated by resource region. To capture differences in cost and performance of units of the same technology within a BA or resource region, we cluster units into "performance bins" based on their generation cost and operating efficiency. Information on this clustering approach is presented in Section 5.3.1.

5.1 Existing and Committed Generation Capacity

Input data for exogenously defined capacity include existing capacity, planned capacity additions, and planned retirements sourced from Palchak et al. (2017), CEA (2018b), and consultations with TANGEDCO. Table 5 summarizes the installed capacity assumed to exist in 2020.

Table 5. Summary of Installed Capacity (MW) by Technology and Region for 2020

	Chennai North	Chennai South	Coimbatore	Erode	Madurai	Tirunelveli	Trichy	Vellore	Villupuram	Total
CCGT-Gas	120				239		639			**998**
Diesel	200				106			106		**412**
Hydro-Pondage			310	90	70	132				**602**
Hydro-Pumped			400							**400**
Hydro run-of-river			555		105					**660**
Hydro-Storage			150	370						**520**
Nuclear		940				2,000				**2,940**
Sub-Coal	2,700			600		2,725			1,250	**7,275**
Super-Coal					800				1,320	**2,120**
Wind			3,206		1,396	5,969	52			**10,623**
Total	**3,020**	**940**	**4,621**	**1,060**	**2,716**	**10,826**	**691**	**106**	**2,570**	**26,550**

Table does not include 3.7 GW solar PV capacity due to incomplete data on the locations of existing plants. Capacity with unknown locations is allocated to resource regions in the planning model based on least-cost criteria.

Planned capacity additions include committed projects with known locations and commissioning dates. These projects include 1,500 MW of new CCGT-gas capacity in Chennai North, a 2,500-MW pumped hydro project in Coimbatore, and several new coal additions across multiple regions. Capacity retirements include planned retirements and age-based retirements based on the plant's economic lifetime and commissioning date. More information on the assumed economic lifetimes for each technology are in Section 5.2.1. Figure 6 shows the planned additions and retirements through the year 2030.

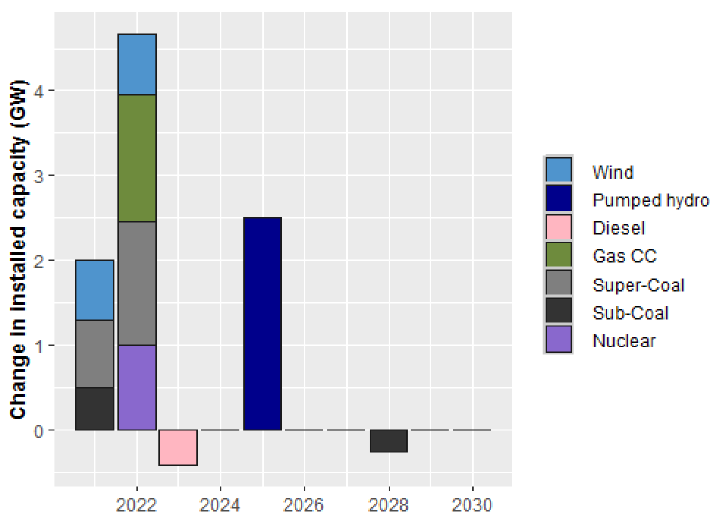

Figure 6. Planned capacity additions and retirements, 2020–2030

5.2 Technology Options for Expansion

Future electricity supply needs can be met by any of the thermal, renewable, or storage-based technologies presented in Table 4. The optimal mix of technologies is based on several factors including the cost of development, operation and maintenance costs, policy targets, and resource availability. The next three subsections present the investment parameters and constraints for capacity investments.

5.2.1 Investment Parameters

Table 6 lists capital cost and plant lifetime assumptions by technology. Unless otherwise stated, all capital costs and plant lifetime data are taken from CEA (2018b). The plant lifetime is the maximum operating age of the plant, after which it must be retired or refurbished.

Table 6. 2020 Capital Cost and Plant Lifetime Assumptions for Generation Technologies

Technology	2020 Capital Cost [a] (₹ crore/MW) [b]	Plant Lifetime (years)
BESS	8.74 [c]	15
CCGT gas	4.6 [d]	55
CCGT LNG	4.6	55
Cogeneration bagasse	5.7	45
CT gas	4.0 [d]	55
Diesel	4.0 [e]	55
DUPV	10.7 [f]	30
Hydro pondage	10.0	100
Hydro pumped	9.9	100
Hydro run-of-river	6.5	100
Hydro storage	9.9	100
Nuclear	10.2	100
Subcritical coal	6.4	25
Subcritical lignite	6.4	25
Supercritical coal	6.4	25
UPV	4.5	30
WHR	5.7 [g]	45
Wind	5.9	24

[a] Capital costs in this report represent the all-in installation cost, including hard costs (i.e., equipment) and balance-of-system costs (i.e., labor, software, permitting, land acquisition, and other fees).

[b] A crore denotes 10 million Indian rupees (INR, ₹).

[c] Based on BNEF (2019)

[d] Based on NREL (2018) assumption that combined cycle units are 17% more expensive that CT units

[e] Based on CEA (2016b) because capital costs for gas plants were unavailable in CEA (2018b)

[f] BNEF (2017) value for commercial rooftop PV

[g] Based on capital cost for cogeneration bagasse

For all technologies, both mature and emerging, there is an exogenous learning rate that results in reductions in capital costs over time as manufacturers and developers gain experience with the technology. We adopt the same learning rates used in NREL's 2018 Annual Technology Baseline "Mid" estimates. Figure 7 shows the anticipated changes in capital cost over the model period for each candidate technology.

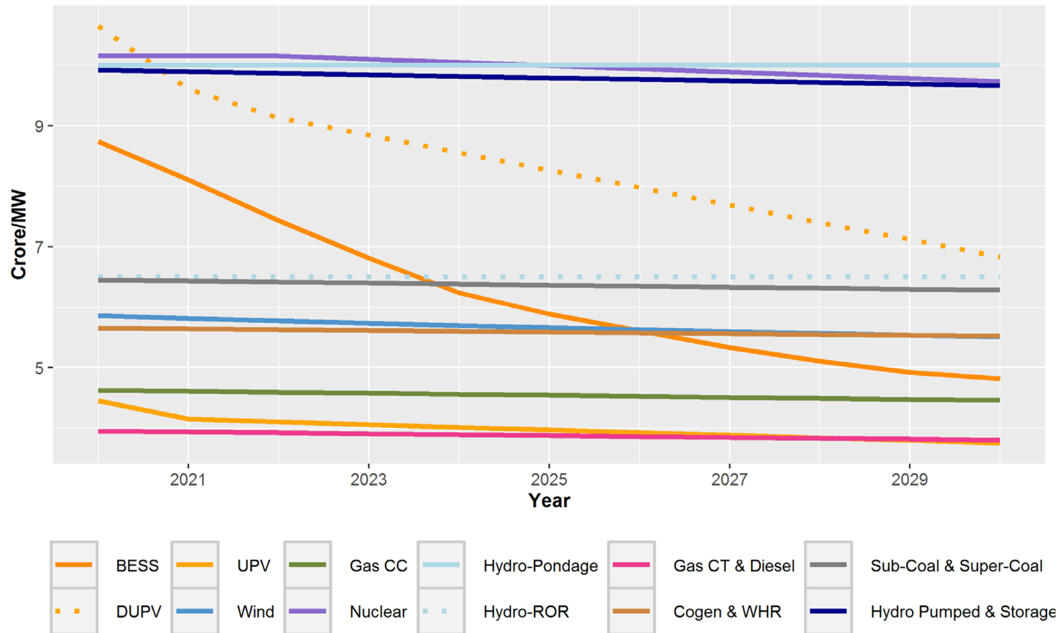

Figure 7. Changes in capital cost over the model period for generation technologies

The **Lower Solar Cost** scenario investigates a different future trajectory for capital costs for solar PV by assuming capital costs decline 50% more rapidly than in the Base scenario such that the 2030 capital cost for solar PV is ₹ 5.1 crore per MW for DUPV and ₹ 2.9 crore per MW for UPV.

5.2.2 Investment Constraints

The investment constraints represent policy, resource, or technical criteria that may influence investment outcomes. We impose five types of investment constraints on generation additions: (1) RE capacity targets, (2) first year for economic capacity additions, (3) absolute growth limits, (4) relative growth limits, and (5) geographic diversity requirements.

The RE capacity targets in Table 7 reflect existing and proposed statewide targets for RE (TEDA 2019).

Table 7. Statewide Wind and Solar Capacity Targets (GW)

Technology	2022	2030 (Base)	2030 (High RE Target)
Solar PV	9	11	18.6
UPV	5.4	6.6	11.2
DUPV	3.6	4.4	7.4
Wind	11	13	20

The first year for endogenous capacity additions is the initial year when new capacity can be built based on economic criteria. Before the first year, only planned additions can be added. For all technologies except wind and solar, we assume projects not already underway will not be complete by 2023. Therefore, these technologies cannot begin economic builds until 2023.

The absolute growth limit represents the state-wise capacity limits over the entire model period on hydro, biomass, and WHR technologies based on their estimated potential (CEA 2018b; CEA 2018c). Table 8 contains the absolute growth limits for each technology type in Tamil Nadu.

Table 8. Absolute Growth Limits on Installed Capacity for Select Technologies (MW)

Technology	Capacity Limit (MW)
Cogeneration bagasse	1070
Hydro pondage	602
Hydro pumped	400
Hydro run-of-river	660
Hydro storage	520
WHR	601

The 2020 installed capacity for all types of hydropower already reaches the estimated potential limit. Additional feasibility studies confirm the feasibility for the planned 2,500-MW pumped hydro plant in Coimbatore.

Finally, we use relative growth and geographic diversity constraints to prevent unrealistic rates of capacity growth in any single year or location. All technologies except BESS are constrained with a 50% year-over-year limit of growth relative to installed capacity in the previous year. Under the geographic diversity constraint, investments in wind and solar must be geographically disperse such that no more than 15% of annual additions are placed in a single resource region. This constraint is based on national wind and solar additions; at the state level, the concentration of wind and solar investments in a single resource region may exceed 15%.

5.2.3 Renewable Resource Supply Curves

We use supply curves for wind and solar to characterize the potential sites available for development and directly evaluates the investments of these generation sources. These supply curves are estimated from detailed weather data, geospatial constraints, and economic assumptions using the process presented in Figure 8.

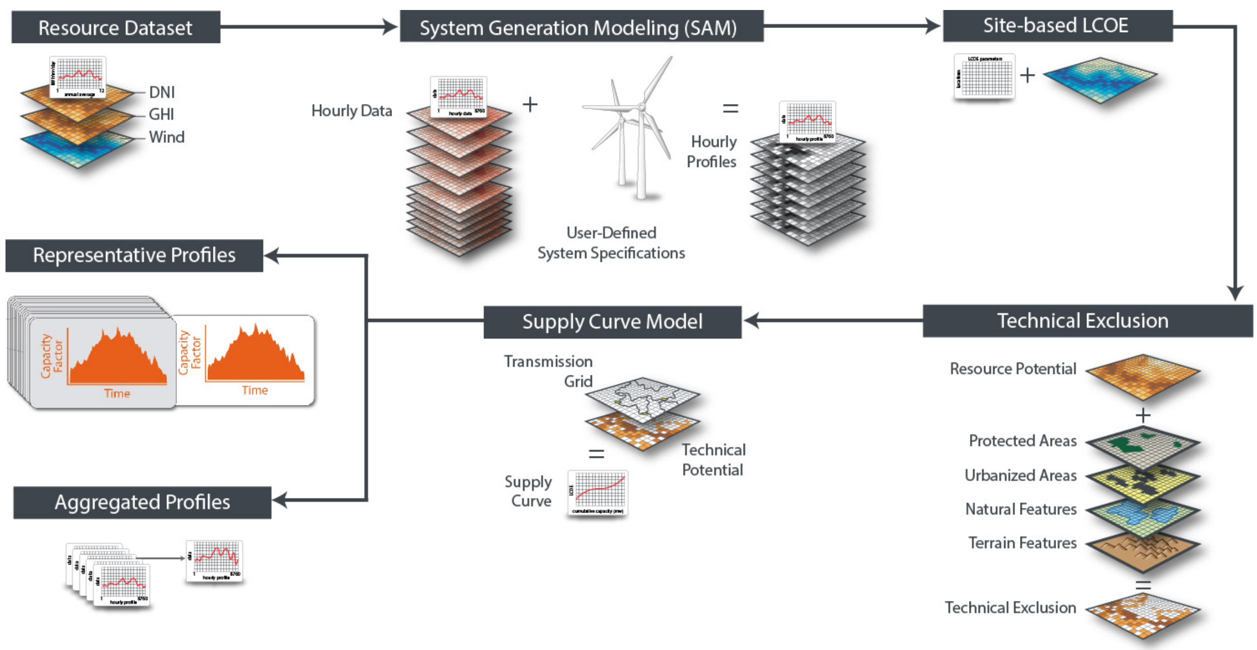

Figure 8. Process to create the RE supply curves

Source: Maclaurin et al. 2019

DNI = direct normal irradiance, GHI = global horizontal irradiance;
Direct normal irradiance and global horizontal irradiance are measures of solar energy potential.

First, we input detailed spatio-temporal weather data and predefined system configurations for candidate technologies to create hourly generation profiles for each location and technology based on a recent weather year[5]. These are combined with financial assumptions about technology capital costs, fixed operating costs, and grid integration costs (i.e., transmission upgrades) to calculate site-based levelized cost of energy. Land exclusion filters based on geospatial data on land characteristics, uses, and cover are applied to eliminate areas unavailable for development. We also include land exclusions based on expert feedback from TANGEDCO. After removing exclusion areas, a final technical potential for each gridded area is combined with geospatial information on the transmission network to create a resource supply curve based on total levelized cost of energy, which includes both site-based and transmission cost considerations. Finally, hourly profiles for each potential site are created to estimate generation, curtailment, and capacity credit for all wind and solar investments.

Solar and wind technologies in each gridded cell are assigned to classes based on the quality of the resource (i.e., irradiance or wind speed) at a specific location. Solar has more resource classes (nine), representing the larger range of resource values in which solar plants can operate. By contrast, wind generation operates in a narrow range of wind speeds and has only three resource classes. Table 9 summarizes the resource classes for wind and solar based on annual average resource quality.

[5] We use the 2014 weather year with detailed temporal and spatial resolution for both wind and solar resources. See Palchak et al. 2017 for details on resource data.

Table 9. Summary of Wind and Solar Resource Classes

Class	Solar (kWh/m^2-day)	Wind (m/s)
1	3.0–3.5	>9
2	3.5–4.0	>8–9
3	4.0–4.5	≤ 8
4	4.5–5.0	—
5	5.0–5.5	—
6	5.5–6.0	—
7	6.0–6.5	—
8	6.5–7.0	—
9	7.0–7.5	—

Based on these classes, Figures 9–11 summarize the wind and solar supply curves, which represents the total cumulative capacity that could be built for Tamil Nadu regions.

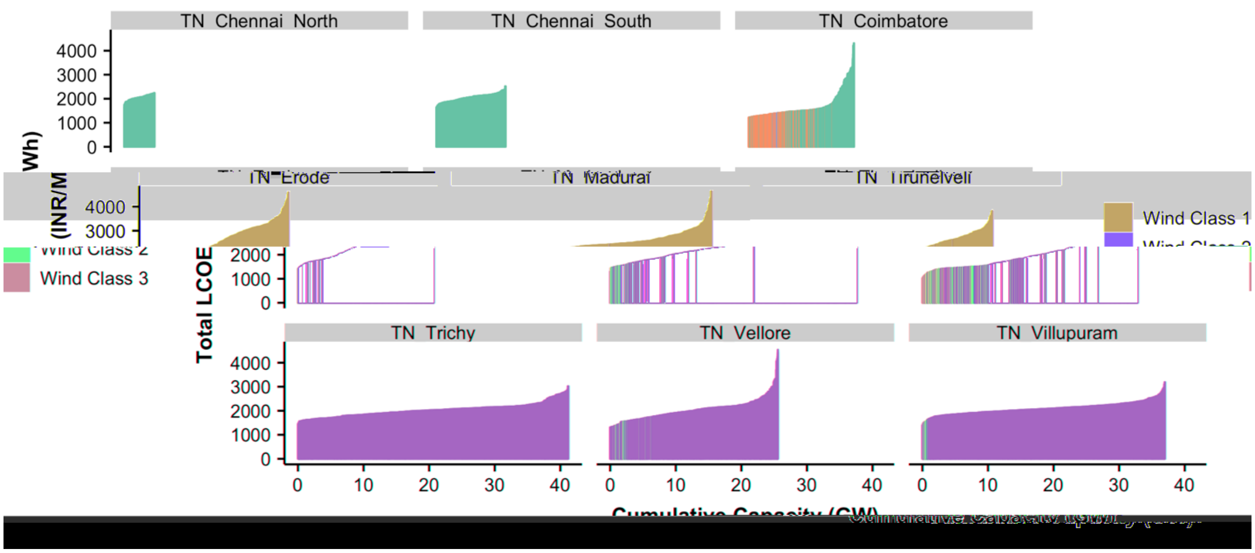

Figure 9. Wind resource supply curve

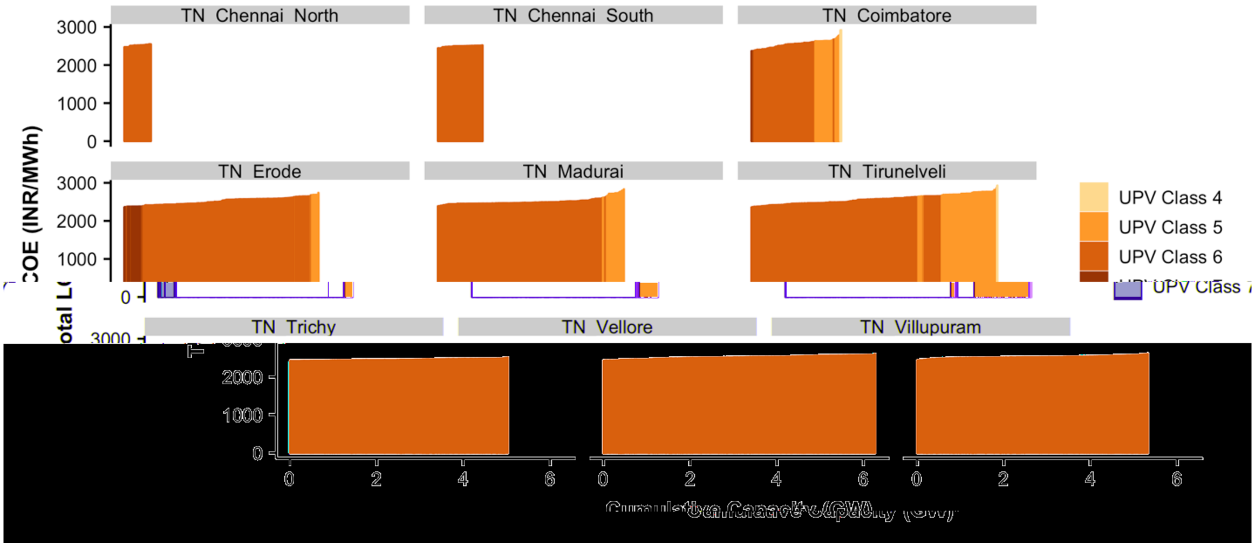

Figure 10. UPV resource supply curve

Not all solar resource classes (i.e., Classes 8 and 9) are available in Tamil Nadu.

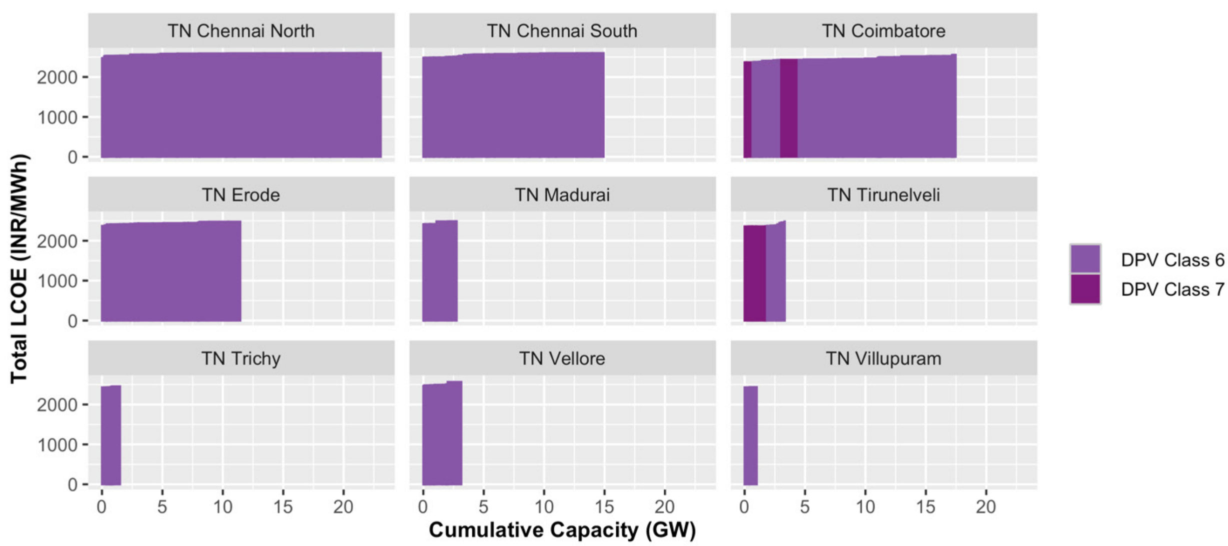

Figure 11. DUPV resource supply curve

Not all solar resource classes (i.e., Classes 8 and 9) are available in Tamil Nadu.

Areas with stronger renewable resources (higher wind speeds or solar irradiance) tend to have lower levelized cost of energy values, meaning these areas are less expensive to develop; however, this is not always the case, as can be seen in Figures 9–11 where, for example, areas with strong wind resources ("Wind Class 2") have higher levelized cost of energy values than areas with lower wind resources ("Wind Class 1"). This can occur if no transmission is available in the vicinity and the assumed cost for grid integration is high. This example demonstrates the value of including detailed geospatial data for both renewable resources and grid infrastructure to improve the estimated cost of developing a particular site.

Using this information, each of Tamil Nadu's 32 resource regions is assigned a maximum developable capacity (MW), interconnection cost (INR/MW), and capacity factor by time-slice and hour for every applicable resource class of wind, UPV, and DUPV.

5.3 System Operations

ReEDS uses a reduced form-dispatch where aggregated generation technology types, rather than individual units, are dispatched to meet requirements for operating reserves and electricity demand in each time-slice. This section presents the operational characteristics and constraints designed to capture the cost and performance characteristics of each technology type. Unless otherwise stated, all operating parameters are taken from Palchak et al. (2017).

5.3.1 Operating Parameters

Within the same region or type of technology, individual units can have different operating costs and performance. In addition, for many technologies the operating costs and plant efficiency are expected to change over time. We use the variable operation and maintenance (VOM) cost to capture differences in unit cost and performance for existing, planned additions, and new generation capacity. Within each BA, we cluster individual units into "performance bins" or group of units with similar costs. We stipulate that each bin for existing units must have at least five units and that the minimum deviation in average variable cost between bins must exceed 200 Indian rupees (INR) per MWh.[6] Table 10 contains the average VOM cost and heat rate for each technology type in Tamil Nadu. We assume DUPV, UPV, wind, and hydropower have no variable cost.

Table 10. Average VOM and Heat Rate Assumptions by Technology

Technology	2020 VOM Cost (INR/kWh)	Annual VOM Cost Decline (INR/kWh)	2020 Heat Rate[a] (GJ/MWh)	Annual Heat Rate Improvements[b] (%)
BESS	7.2	0.34	—	—
CCGT gas	6.4	0.10	7.3	0.2%
CCGT LNG	6.1	—	7.3	0.2%
Cogeneration bagasse	4.9	—	12.3	—
CT gas	8.0	—	11.3	0.6%
Diesel	2.4	—	11.5	—
Nuclear	2.5	—	—	—
Subcritical coal	2.2	—	11.1	—
Subcritical lignite	2.2	—	11.1	—
Supercritical coal	2.5	—	11.2	0.05%
WHR	3.8	—	—	—

[a] Value assumed for all plants commissioned in or before 2020

[b] Based on NREL 2018

[6] We assume an exchange rate of 70.2 Indian Rupee (INR) to 1 U.S. dollar

Other operating parameters are expected to experience less variation between model regions and over time. Table 11 contains the input parameters assumed to remain constant for all BAs and model years.

Table 11. Technology Operating Parameters Assumed Constant Across All BAs and Model Years

Technology	Ramping Limit (MW/min)	Min. Loading Fraction	Planned/Unplanned Outage (%)
BESS	15.3	—	0/0
CCGT gas	3.4	0.50	2.4/8.5
CCGT LNG	5.5	0.50	2.4/8.5
Cogeneration bagasse	0.5	0.50	2.4/8.5
CT gas	1.8	—	4.1/4.3
Diesel	1.8	0.50	4.1/4.3
DUPV	—	—	0/0
Hydro pondage	10.5	—	0/0
Hydro pumped	15.3	0.20	0/0
Hydro run-of-river	5.4	—	0/0
Hydro storage	8.2	—	0/0.7
Nuclear	1.7	1.00	2.3/8.3
Subcritical coal	3.8	0.55	5.1/10
Subcritical lignite	1.5	0.55	5.1/10
Supercritical coal	10.2	0.55	5.1/8
UPV	—	—	0/0
WHR	0.5	—	5/8.5
Wind	—	—	0/0

Text Box 2. Approximation of Operational Aspects of VRE Technologies

As the penetration of VRE and storage technologies increase, a more detailed representation of system operations becomes increasingly important in the planning problem. ReEDS addresses this challenge by simulating time-synchronous hourly operations to estimate curtailment for each capacity expansion solution.

Curtailment is a reduction in generation from what a generator could otherwise produce given available resources. For VRE generators, curtailment can occur when there are high levels of inflexible "must-run" capacity committed or there is insufficient demand for the generation locally. Transmission congestion can also impact curtailment if network constraints prevent the export of excess power. The amount of curtailment may impact the economics of investment in VRE technologies.

The ReEDS curtailment module uses a statistical convolution approach to estimate the amount of VRE curtailment in each region and time-slice based on the expected value of (1) electricity demand, (2) minimum turn down of committed plants, (3) network flows, and (4) VRE generation. The output includes estimates of when and where curtailment is likely to occur for existing and candidate VRE technologies. Both (1) recommitting thermal capacity to change the minimum stable output level of the thermal fleet and (2) investing in energy storage and effectively increasing the available load could reduce curtailment levels. Therefore, the curtailment module also estimates the marginal impact of recommitting thermal capacity or adding new storage capacity on curtailment levels. This information is returned to the optimization problem to adjust the levels of VRE investments, storage investments, and dispatch decisions for the thermal fleet.

5.3.2 Operating Constraints

The operating constraints represent technical and resource-based limits on how technologies may be dispatched. These include: (1) seasonal limits on hydropower generation, (2) limits on gas fuel supplies, (3) minimum loading for CCGT gas, and (4) seasonal minimum loading limits.

Seasonal rainfall patterns directly impact potential generation from hydropower plants throughout the year. We include seasonal capacity factors for each type of hydropower generator to account for variations in water available for hydropower generation. Using Central Electricity Authority's monthly generation data for 18 hydropower plants during 2015–2016 and 2016–2017 (CEA 2016a), we calculate average seasonal capacity factors for each plant in the report. We combine this with the power plant database from Palchak et al. (2017) and other publicly available sources to classify each plant as run-of-river, pondage, storage, or pumped and we calculate the average capacity factor by plant type (Table 12).

Table 12. Seasonal Capacity Factors for Hydropower Technologies

Plant Type	Pre-Winter	Winter	Spring	Summer	Monsoon	Autumn
Pondage	0.22	0.16	0.16	0.14	0.26	0.28
Pumped	0.10	0.13	0.13	0.06	0.08	0.09
Run-of-river	0.14	0.16	0.21	0.17	0.19	0.25
Storage	0.11	0.13	0.19	0.10	0.15	0.19

A shortcoming of this approach to estimating hydropower availability is that historic generation patterns are not solely based on water availability; hydropower generation may depend on other factors such as electricity demand, the availability of other generation resources, and water needs for other uses such as agriculture and flood control. Improving the estimates for hydropower availability is an area for future work.

National fuel supply limits are imposed on gas technologies based on historical domestic and imported gas supplies. In the **Base scenario**, we assume no change in available gas supplies from 2020 (CEA 2019). For the **New Gas scenario**, we assume new import terminals help to ease supply restrictions over time. The maximum available gas supply is reached in the year 2024, after which the gas fuel limit remains constant through 2030 (Table 13). In both scenarios, gas fuel for new plants is assumed to come from imported LNG sources.

Table 13. Fuel Supply Limits on Gas for the Base and New Gas Scenarios

Units are million metric standard cubic meter per day.

Year	Base scenario	New Gas scenario
2020	20	71.6
2021	20	89.0
2022	20	105.9
2023	20	123.5
2024–2030	20	128.47

Gas plant operations in India are limited by long-term fuel supply contracts. A gas supply contract typically takes the form of a "take-or-pay" agreement, wherein daily gas delivery volumes are agreed on several months or years in advance of actual delivery. This type of fuel supply agreement prevents the gas fleet from adjusting unit commitment decisions based on daily, weekly, or seasonal variations in energy demand. To approximate the contractual limitations on the timing of gas fuel supply, the fleet of combined-cycle gas plants in each BA must generate in all times and seasons in a given year or not at all.

The constraint on timing of fuel supply is not imposed on open-cycle gas plants (CT gas). We assume that CT gas plants can enter flexible fuel supply contracts that enable delivery of fuel when it is needed. We also assume that necessary upgrades are made to the gas pipeline infrastructure, including compressor stations and pipeline network expansions, to enable flexible timing in the delivery of gas fuel for peaking plants. As with other technologies, the cost of new infrastructure investments to enable fuel delivery are assumed to be reflected in the plant's delivered fuel cost.

Finally, we impose minimum generation limits to restrict unrealistic plant cycling within each season. For any given season and BA, technologies that are dispatched must generate at or above their minimum loading level described in Table 11. This constraint prevents a situation where, for example, thermal capacity is dispatched during the morning peak, turned down to zero midday, and dispatched again to meet evening peak demand.

6 Transmission

ReEDS uses an aggregated transmission network, capturing the combined carrying capacity of interstate lines between BAs based on Palchak et al. (2017), which represents a close approximation of existing transfer capacities with reliability-based flow limits. A transportation, or pipe flow model, approximates power flows between BAs.[7] Figure 12 shows the available transfer capacities between Tamil Nadu BAs based on existing lines for 2020–2022.

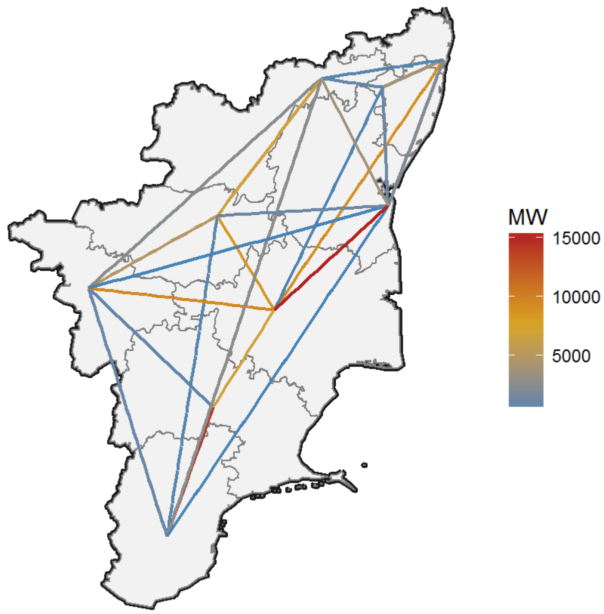

Figure 12. Transfer capacity available between BAs

The transmission database also includes interconnects with neighboring states. Table 14 shows available transfer capacity between Tamil Nadu regions and neighboring states.

[7] A transportation model ignores reactive power and Kirchhoff's current and voltage laws. We assume power flows from one region to the other without impacting the rest of the network.

Table 14. Available Transfer Capacity With Neighboring States

Tamil Nadu BA	BA	Line Type	Transfer Capacity (MW)
Vellore	Andhra Pradesh	AC	1,751
Vellore	Karnataka	AC	4,046
Coimbatore	Kerala	AC	1,165
Madurai	Kerala	AC	131
Tirunelveli	Kerala	AC	3,098
Trichy	Kerala	DC	2,000
Chennai South	Puducherry	AC	517
Villupuram	Puducherry	AC	917
Trichy	Chattisgarh	DC	6,000

6.1.1 Transmission Investments

Transmission expansion is modeled as additional transfer capability (MW) between BAs built at a BA-to-BA-specific per unit cost (INR/MW-km). Using this approach, the total cost of adding transfer capacity between two BAs depends on the capacity being added and the distance between the BAs.

We estimate the capital cost for inter-BA lines based on the investment cost for the highest voltage line on each BA connection. In Tamil Nadu, these voltages are 765 kV and 400 kV. Table 15 contains the capital cost assumptions for each BA in Tamil Nadu.

The final capital costs used in the model are obtained by dividing the per km costs by the average carrying capacity of the interstate lines for that voltage in each BA. The distance between BAs is estimated using the geographic coordinates of the largest population center of each BA.

Table 15. Capital Costs for Select Transmission Voltages

BA	Highest voltage inter-BA line (kV)	Capital Cost (Lakh/km)[a]	Transmission Cost (Lakh/MW-km)
Chennai North	765	413	0.54
Chennai South	400	124	0.67
Coimbatore	765	413	0.54
Erode	765	413	0.54
Madurai	400	124	0.56
Tirunelveli	765	413	0.54
Trichy	765	413	0.61
Vellore	765	413	0.61
Villupuram	765	413	0.49

[a] One Lakh denotes 100,000 rupees.

6.1.2 Substation Supply Curves

The substation supply curves capture the cost of stepping up the voltage within a BA to reach the voltage of inter-BA transmission. The supply curve is an estimate of the costs of distributing power from large, high-voltage, inter-BA lines built by ReEDS to the existing intra-BA network. We assume new renewables can use existing infrastructure to step up the voltage to the high-voltage buses to transmit their generation. If there are not enough buses to distribute/collect the power, the cost of purchasing new infrastructure is added to the total transmission cost.

The substation supply curves are based on the cost of transformers (INR/MW) at different voltage levels and an estimate of how much line capacity (MW) can be tied into a specific bus. The final supply curve consists of a carrying capacity (MW) and marginal cost (INR/MW) for each voltage class by BA. The carrying capacity is calculated as the number of substations in each BA at a specified voltage times the carrying capacity for that voltage. The marginal cost to distribute power in each BA is equal to the cost to step up the voltage from each voltage class to the inter-BA transmission voltage. The transmission supply curves inform decisions about necessary network investments and siting decisions for new generation; they do not replace the need for detailed transmission planning supported by power flow analysis.

7 Reliability

We include two types of reliability constraints: a planning reserve margin and operating reserve requirement. The planning reserve margin requires each of India's operating regions (e.g., Southern Region) maintain adequate installed capacity meet peak demand plus 15% in every season (CEA 2019).[8] The amount of installed capacity considered "firm" or available to contribute to the planning reserve margin requirement depends on the technology type. Conventional generation technologies receive full capacity credit toward meeting the planning reserve margin with no seasonal variation. The firm capacity for dispatchable hydro technologies (i.e., hydro pondage and storage) is based on the installed capacity times the average seasonal capacity factor for that technology. For wind, solar, and storage technologies, firm capacity is estimated based on hourly simulations of generation and demand to determine each technology's contribution to reduce the coincident peak net load in each region and season.

The operating reserve requirement is equal to 5% of national demand in each time-slice. The contribution of different technologies to the operating reserve requirement is limited by the ramping capability for that technology. The assumptions for operating reserve costs and technology-specific contributions (Table 16) are based on Brown et al. (2020).

Table 16. Input Assumptions for Operating Reserve Costs and Capabilities

Technology	Cost of Operating Reserve Provision (INR/MWh)	Contribution of Capacity to Operating Reserve Requirement (%)
CCGT gas	421	30
CCGT LNG	421	30
CT gas	271	30
Diesel	281	20
Hydro pumped	140	100
Hydro storage	140	100
Subcritical coal	702	10
Subcritical lignite	702	10
Supercritical coal	1,053	10

[8] The planning reserve margin is taken as an exogenously assigned requirement. Assessing the appropriate level of reserve requirements is an area for future work and outside the scope of this study.

8 Results

This section presents the results of the capacity expansion plan, which examines the development of the Tamil Nadu power system to 2030 under a Base scenario (Section 8.1) and multiple alternatives (Section 8.2) that explore uncertainty in future component costs, state policy, gas availability, and fuel availability.

8.1 Base Scenario

Anticipated changes in electricity demand and component costs combined with state policy can drive a significant shift in the electricity supply of Tamil Nadu's power system and how this system will be operated. The Base scenario reflects a future in which technology cost and demand growth trajectories follow current trends and projections. This scenario provides insight into what might be a plausible future for Tamil Nadu's electric power system given anticipated trajectories for policy or technology development; the scenario also helps provide a business-as-usual case to measure how sensitive the future is to changes in costs, fuel availability, or changes to other system parameters.

8.1.1 Installed Capacity

In the Base scenario, the total installed capacity over the planning period increases from 31 GW in 2020 to 60 GW in 2030. Figure 13 shows the evolution of Tamil Nadu's installed capacity over the modeling period. Capacity additions and retirements are fixed based on current plans through the year 2022. After that, the model optimizes the capacity mix in each year to achieve a least-cost system compliant with state RE targets.[9]

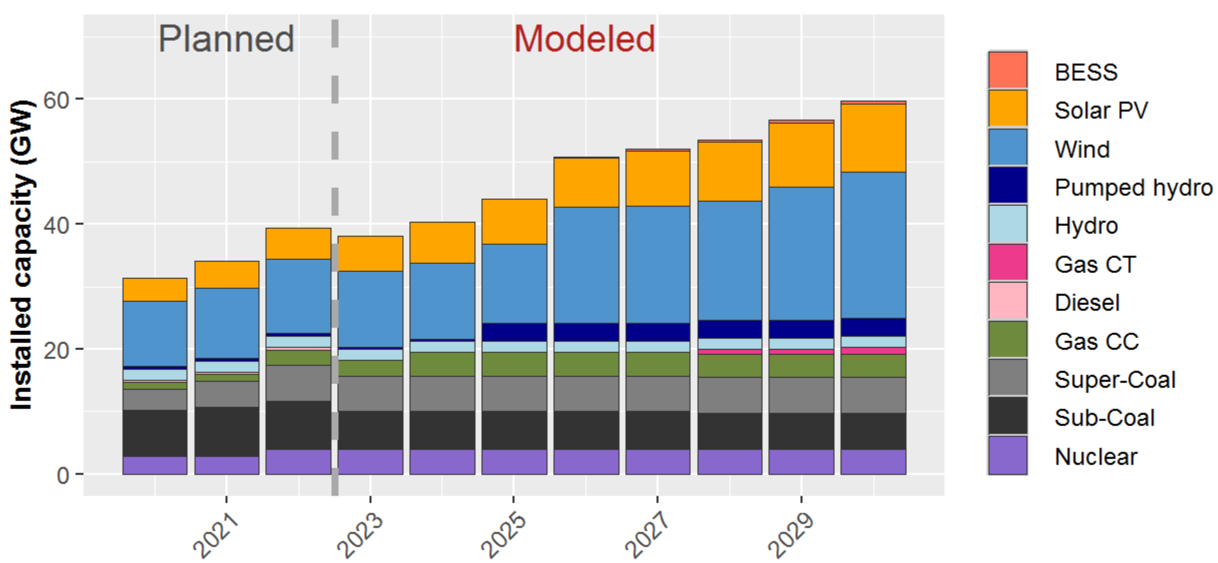

Figure 13. Total installed capacity, 2020–2030 in the Base scenario

The majority of new investments are from wind, solar PV, and gas technologies. Investments in wind are economic beyond the target set by the state. By 2030, Tamil Nadu has over 23 GW of

[9] The planned 2,500 MW pumped hydro plant added in 2025 is the sole exception.

wind capacity compared to the state target of 13 GW. There are no economic investments in coal beyond the capacity already planned. There are 3.9 GW of investments in new gas and gas CC capacity to provide firm capacity to meet the planning reserve margin. Gas technologies are good candidates for providing firm capacity with low utilization rates because they are inexpensive to build relative to other conventional technologies. Investments in gas CT are constrained by the relative growth limit; absent this constraint, gas CT is favorable to gas CC due to its lower capital cost. Investments in BESS begin after the year 2025. Falling technology costs and increased deployment of wind and solar resources, which are complemented by BESS's ability to shift energy from high-RE periods to high-load periods, make BESS investments increasingly economic. Table 17 illustrates how the installed capacity changes over time.

Table 17. Evolution of Installed Capacity by Technology, Base Scenario

Technology	2020		2030	
	GW	% of total	GW	% of total
BESS	—	—	0.4	1
Solar PV	3.7	12	11	18
Wind	10.5	33	23.3	39
Pumped hydro	0.4	1	2.9	5
Hydro	1.8	6	1.8	3
Gas CT	—	—	1.1	2
Diesel	0.4	1	—	—
Gas CC	1	3	3.8	6
Super-Coal	3.4	11	5.7	10
Sub-Coal	7.3	23	5.8	10
Nuclear	2.9	9	3.9	7
Total	**31.4**	**100**	**59.7**	**100**

The distribution of generation capacity across the state varies between BAs based on available resources and the cost of developing those resources. Figure 14 shows the installed capacity of coal, gas, and BESS in 2030.

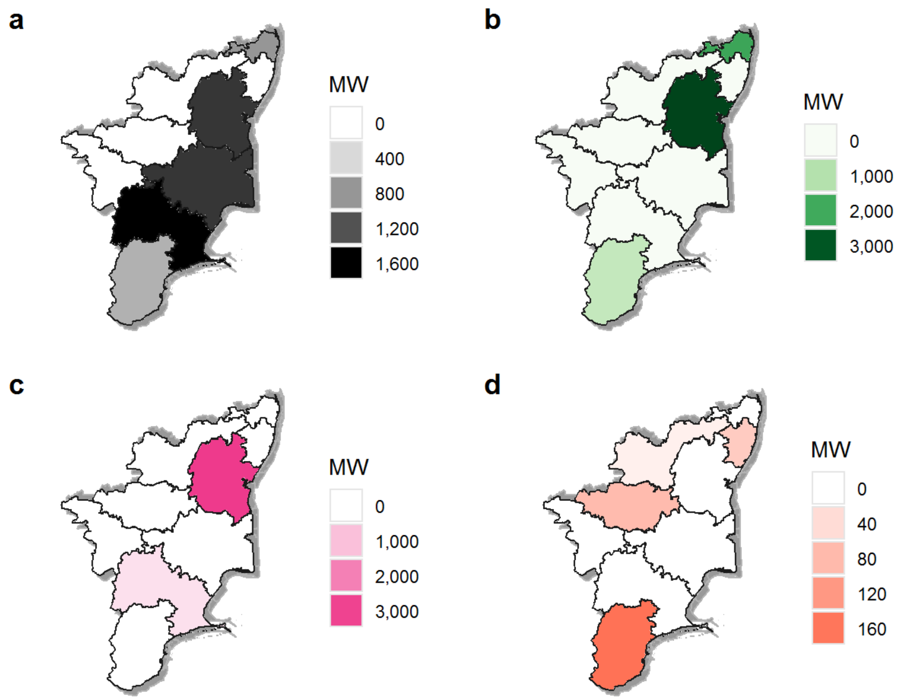

Figure 14. Location of (a) supercritical-coal, (b) gas CC, (c) gas CT, and (d) BESS in 2030, Base scenario

Most of the supercritical coal is located along the eastern half of the state in 2030. Gas capacity is concentrated near Chennai, the state's largest load center, while investments in BESS are highest in the southern region of Tirunelveli where wind capacity is highest.

By 2030, more than 34 GW of wind and solar PV are deployed in the Base scenario accounting for more than 50% of installed capacity. This capacity is concentrated in areas with the best resource and lowest grid connection cost (Figure 15). The Tirunelveli district in the south accounts for over 9.6 GW or 43% of the state's wind capacity. UPV and DUPV are more dispersed throughout the state with the greatest concentration in Nagappattinam and Tiruppur for UPV and DUPV, respectively.

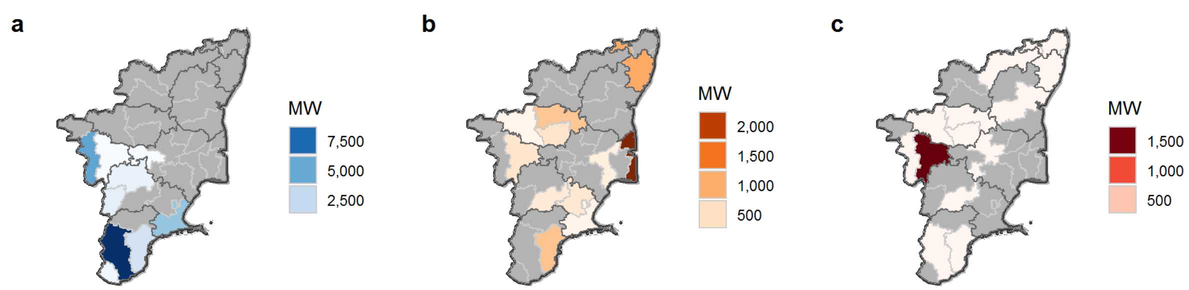

Figure 15. Location of (a) wind, (b) UPV, and (c) DUPV in 2030, Base scenario

Figure 16 shows the mix of installed capacity that contributes to the planning reserve margin in 2020 and 2030. By 2030, Tamil Nadu has adequate firm capacity to meet peak demand (black dot) for half of the year. During other months, deficits are met through imports with neighboring states. During the summer season (mid-May to mid-July), Tamil Nadu has enough firm capacity to meet peak demand plus the 15% reserve margin (red dot). Conventional generators, including nuclear, coal, and gas are the largest sources of firm capacity. Wind, and to a lesser degree, solar PV and BESS, also contribute, but their availability varies considerably by season. During the summer season (mid-May to mid-July), 23 GW of wind capacity contribute 13 GW or 57% toward the planning reserve requirement. For all seasons, we estimate at least 2 GW of wind can be considered "firm" or available during the highest demand hours. The fraction of capacity estimated as firm is lower for solar PV due to the mismatch between hours when demand is highest and when solar PV is generating. During the monsoon season, solar PV contributes 1.2 GW or 11% of its installed capacity to the planning reserve margin. In other seasons, less than 0.01 GW of solar is reliably available during peak hours.

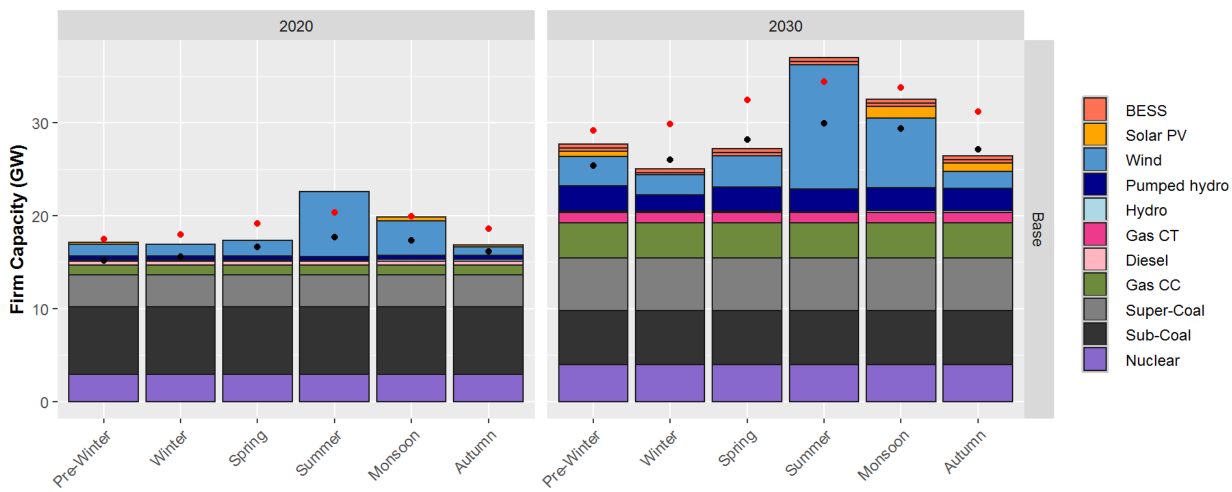

Figure 16. Mix of technologies used to meet the planning reserve margin, Base scenario

Black dots indicate peak demand, and red dots indicate the planning reserve margin requirement.

By 2030, the total firm capacity does not always meet state level requirements because there is capacity built within other Southern Region states used to meet the planning reserve margin in Tamil Nadu.[10] It is notable in Figure 16 that, in a future system with high penetrations of RE, capacity additions are driven by the coincidence of demand and RE generation rather than peak demand alone. In 2030, the system has the highest surplus capacity during the peak demand months in summer because high wind speeds mean more wind generation is available to meet peak demand during these months. The lowest margin of excess capacity is during the moderate demand months in spring when wind generation is lower.

[10] This is similar to the current practice of building centrally owned plants in one state designed to meet power system needs of multiple states.

8.1.2 System Operations

Nuclear, wind, and solar PV generation play an increasing role in meeting electricity demand in the Base scenario. Figure 17 shows the evolution of the generation mix over the planning period.

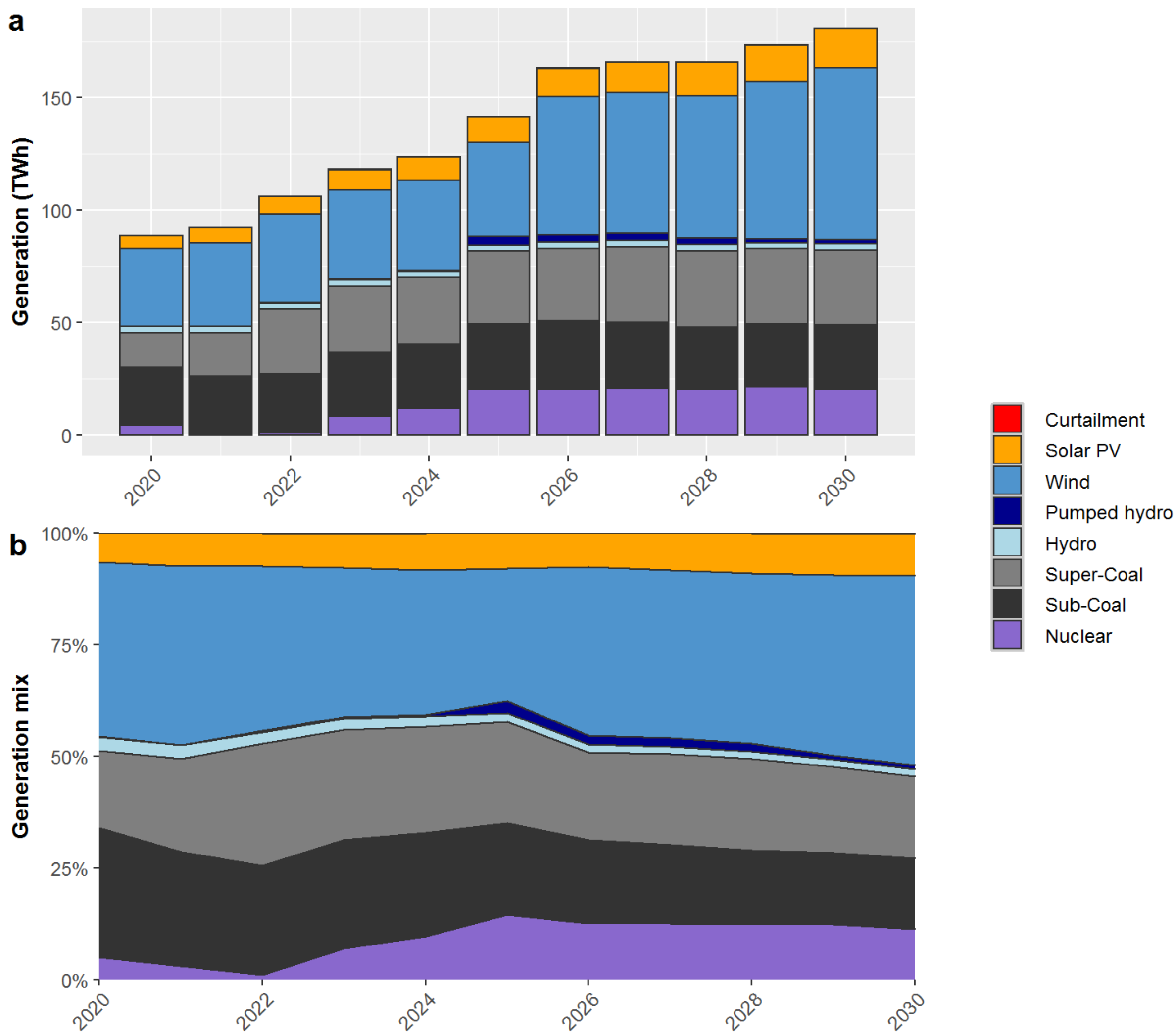

Figure 17 (a) Absolute and (b) relative annual generation mix for 2020–2030, Base scenario

The share of total generation from coal decreases from 46% in 2020 to 35% in 2030, with an increasing share met by supercritical coal while use of subcritical coal plants declines. Planned additions are anticipated to lead to surplus capacity by 2021, leading to a short-term reduction in generation from nuclear technologies. The energy contribution from wind and solar increases from 46% in 2020 to 52% by 2030. In some years, a small amount of VRE (<1%) cannot be absorbed by the system and is curtailed. Table 18 illustrates how the generation mix changes over time.

Table 18. Evolution of Generation Mix (Percentage of Total) by Technology, Base Scenario

Technology	2020	2030
Solar PV	7	10
Wind	39	42
Pumped hydro	–	1
Hydro	3	2
Super-Coal	17	19
Sub-Coal	29	16
Nuclear	5	11

Comparing Table 17 and Table 18, we see that gas CT and gas CC technologies make up around 8% of installed capacity but do not contribute to annual generation. This includes 2.5 GW of existing and planned capacity and 2.4 GW of new capacity built for reliability purposes to meet the planning reserve margin across multiple Southern region states. We do not explicitly model the contingency events in which this margin of available capacity may be required, such as unplanned generation or transmission outages, delayed commissioning of planned projects, droughts, unforeseen increases in electricity demand, or forecast errors in wind and solar generation. During such a contingency, gas capacity may be dispatched to maintain balance of supply and demand in actual operations.

Figure 18 shows the technologies dispatched to meet demand in each time-slice between the 2020 and 2030 model years. For each representative hour, the black dot indicates the electricity demand (GW) and the bar chart shows the mix of generation sources dispatched to meet demand during that period. Periods when the black dot exceeds the bar indicate Tamil Nadu is importing power from generation resources located outside of the state.[11]

[11] We assign generating capacity based on its physical location and do not model commercial contracts for specific generating stations including allocations from central-owned plants. Using this approach, any power sent from a plant located outside of Tamil Nadu would be considered an "import."

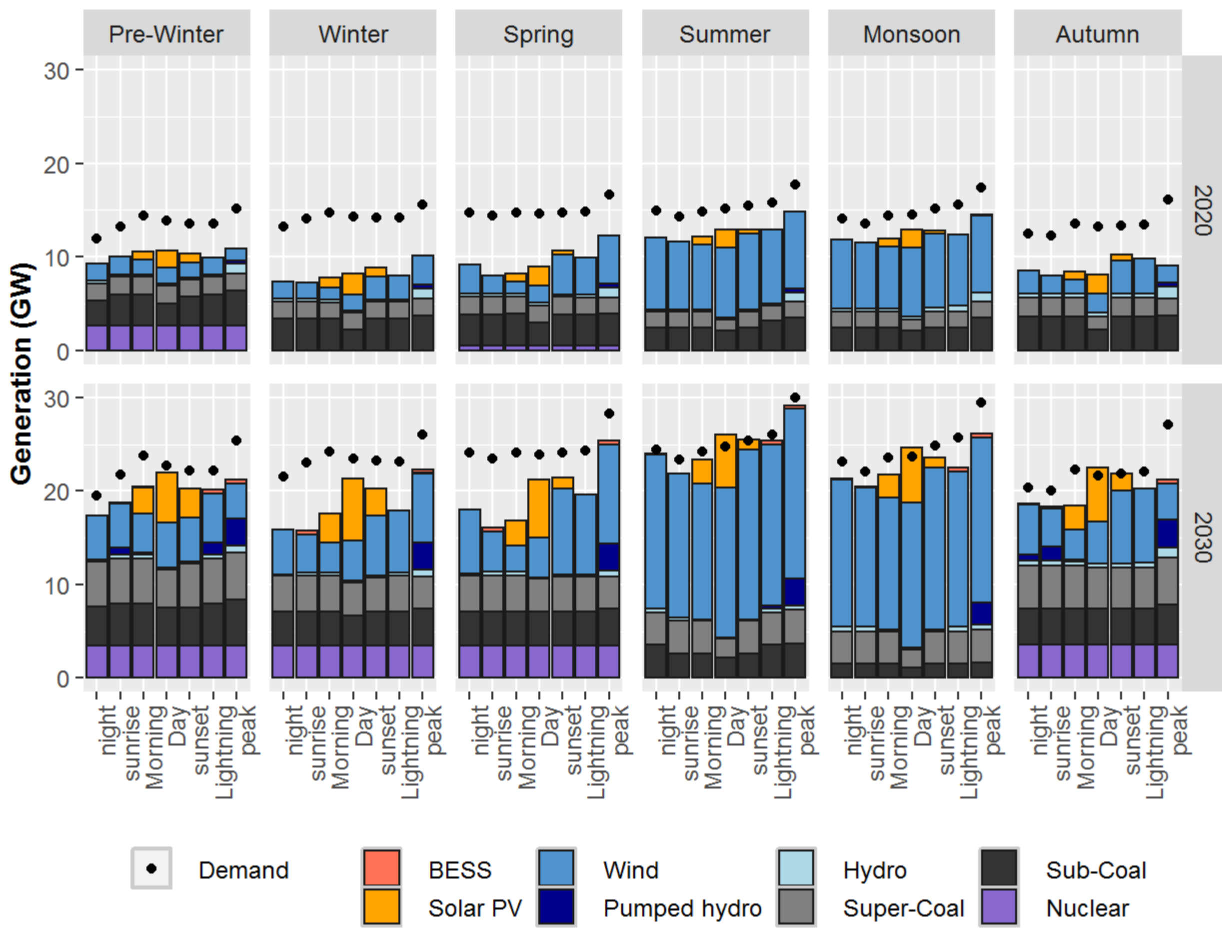

Figure 18. Time-slice generation for 2020 and 2030 model years in the Base scenario

In 2020, conventional thermal technologies provide near-constant output levels, VRE technologies generate when available, dispatchable hydropower is used to meet peak demand, and imports from neighboring states meet the remaining balance of demand. Energy from capacity located outside of the state provides 28% of annual electricity needs in 2020.

By 2030, the daily and seasonal operation of the power system is transformed as wind and solar PV play an increasing role in meeting electricity demand. The share of demand met by capacity outside of the state falls to 11% with the highest level of imports during the sunrise and morning periods of winter and spring. Increased shares of VRE generation require greater flexibility from other grid resources to balance supply and demand. During the summer and monsoon seasons (mid-May through mid-September), over 60% of electricity demand is met by wind. Inflexible nuclear plants are not dispatched at all during these months and coal technologies are backed down to their minimum generation level of 55% installed capacity during the middle of the day when VRE generation is high. In the low-wind seasons of prewinter and winter wind generation is still able to meet more than 20% of electricity demand, but total output falls by two-thirds, requiring increased generation from nuclear and coal resources. While nuclear and coal can respond to seasonal variations in net load, energy storage in the form of pumped hydro and

BESS play a larger role in intraday load following. Figure 19 shows the charging and discharging patterns of energy storage technologies for the year 2030.

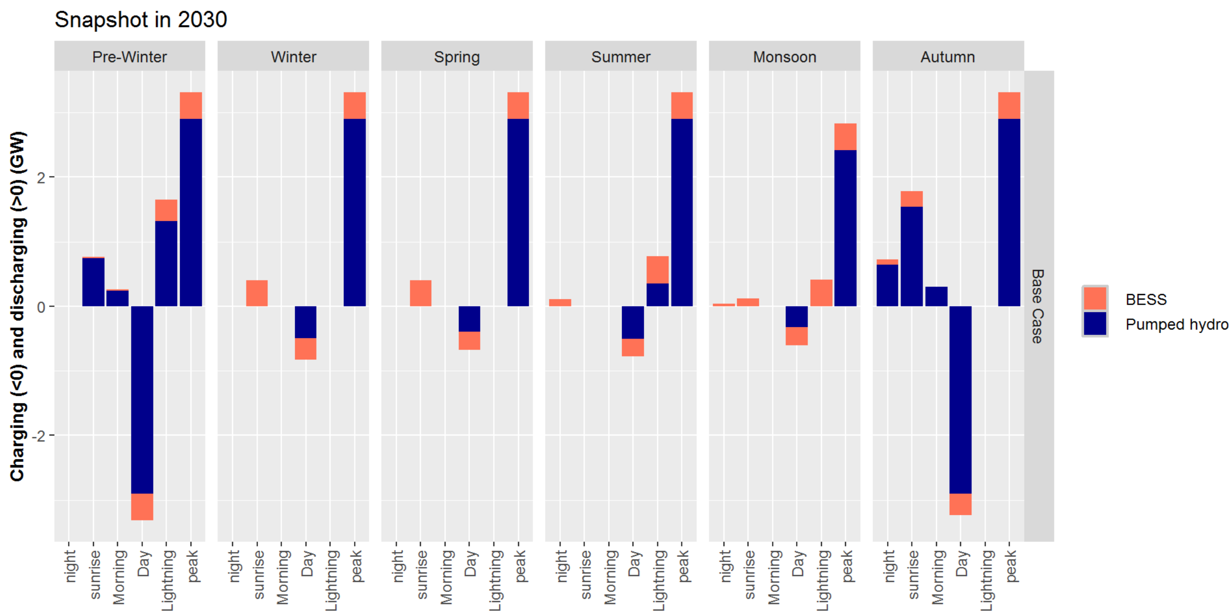

Figure 19. Operation of energy storage technologies in 2030, Base scenario

Energy storage helps maximize the use of solar PV generation by storing energy during the day (i.e., the bars in Figure 18 are higher than the black dots) and discharging during peak demand or evening periods when solar generation is not available. When net demand is close to zero or below zero, energy storage shifts excess energy from thermal plants that are constrained by their minimum generation level, avoiding the need to shut these plants down.

8.1.3 Transmission Investments and Interstate Trade

The model database includes all existing and planned transmission lines through 2022. While there are no additional transmission investments added during the model period, there is a significant change in transmission usage and the patterns of power flows around the state. Figure 20 compares the average line loading for all inter and intrastate transmission corridors in 2020 and 2030.

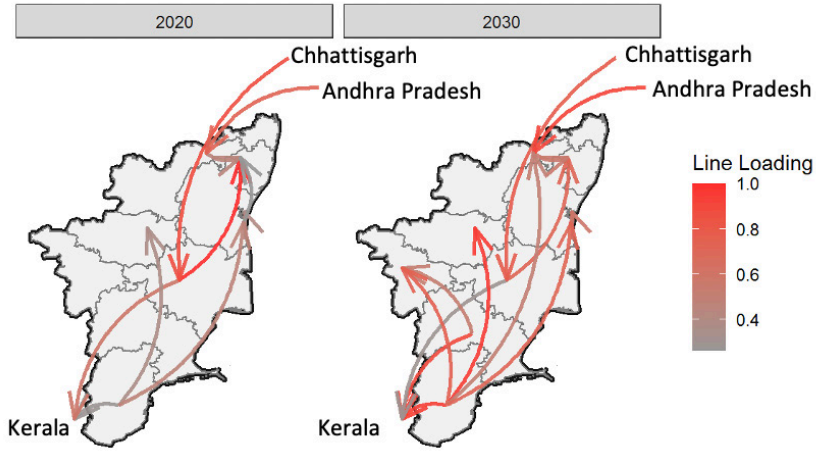

Figure 20. Average line loading in 2020 and 2030 in the Base scenario

Lines with line loading <0.25 not shown.

In 2020, only two transmission corridors have an average loading of greater than 75%. These corridors move power from Chhattisgarh to Trichy and from Trichy to Chennai South. The periods with the highest transmission usage correspond to time-slices with the highest electricity demand in each season. By 2030, there are six transmission corridors with an average loading of greater than 75% and more power is flowing from the south of the state, where wind generation is highest, to meet electricity demand in northern regions or export to Kerala. Tamil Nadu is also importing more power from Andhra Pradesh via the 1,751 MW connection between Andhra Pradesh and the Vellore region.

These results provide insight as to how power flows across the state may change in response to changes in the generation mix and potential areas for future network reinforcements. More detailed power flow studies are required to inform transmission network requirements along with investment decisions.

8.1.4 System Costs

The total present value cost of capital investments and operations over the 11-year model period is ₹ 274,700 crore. This amounts to an average annual expenditure of ₹ 25,000 crore per year. Capital costs for new generation capacity account for 22% or ₹ 61,100 crore. Fixed operation and maintenance costs represent annual per unit of capacity (e.g., per MW) costs incurred to keep a generating station available regardless of the energy produced. These costs account for 37% of the total. Variable costs, including VOM and fuel costs, are the largest contributor to total system costs, accounting for 41% of all costs over the model period. Figure 21 shows the breakdown of total costs by technology and cost type.

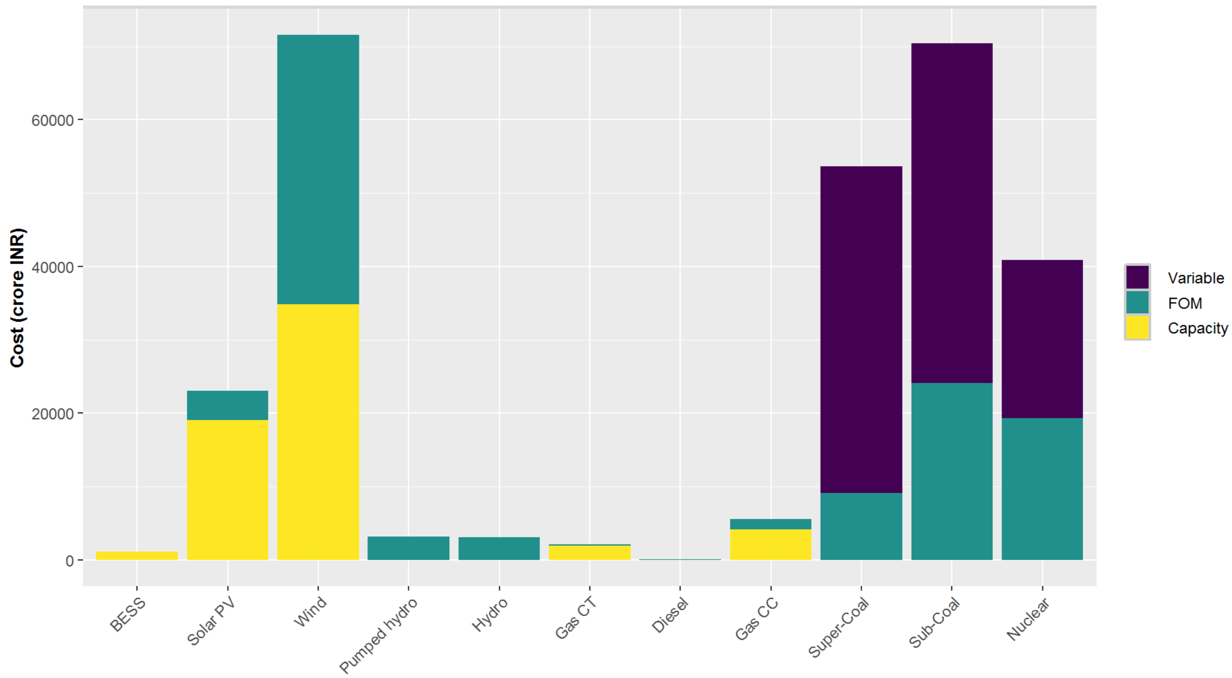

Figure 21. Present value of total costs by technology and cost type

Variable: VOM and fuel costs

FOM: Fixed operation and maintenance costs

Capacity: Capital costs for generation investments

8.2 Scenario Results

As policies and technologies continue to evolve, there is uncertainty about how technology costs, state renewable targets, electricity demand, and fuel availability may evolve over time. To understand how these uncertainties may impact system needs and help inform investment decisions that are robust against a variety of uncertainties, we tested several alternative scenarios described in Table 1. Figure 22 shows the 2030 installed capacity for each scenario.

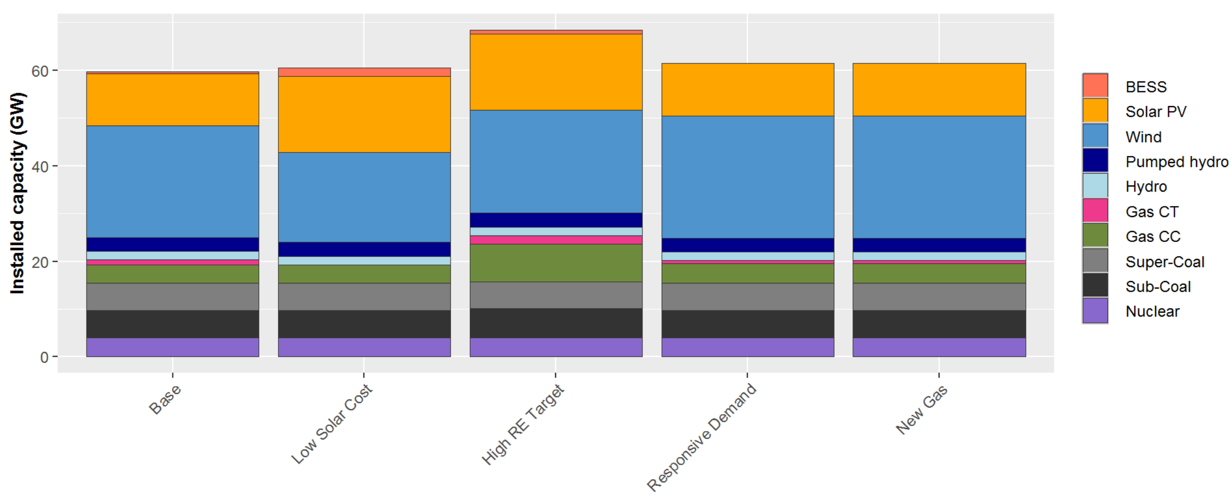

Figure 22. Comparison of 2030 installed capacity for all scenarios

Both the **Low-Cost Solar** and **High RE Target** scenarios result in increased investments in solar PV and BESS compared to the **Base** scenario. In some scenarios, investments in gas CT are delayed or displaced due to increased investments in VRE (e.g., Low Solar Cost, Responsive Demand).

8.2.1 Low Solar Cost

The **Lower Solar Cost** scenario investigates a future in which capital costs for solar PV decline 50% faster than anticipated in the Base scenario. Lowering solar PV costs make solar more competitive with wind as a source of new capacity. Total solar capacity increases from 11 GW in the Base scenario to 16 GW while investments in wind decrease slightly from 23 GW to 22 GW. While solar PV and wind are competing technologies, solar PV and BESS are complementary; decreasing the cost of one tends to increase investments in both because of BESS's ability to store excess solar generation and discharge during peak demand periods. In the Low Solar Cost scenario investments in BESS increase slightly from 0.3 GW to 0.8 GW. Figure 23 compares the operation of energy storage in the Base and Low Solar Cost scenarios. Increased solar PV and BESS capacity increases the amount of energy being stored during the middle of the day and discharged to meet the peak and nighttime demand periods.

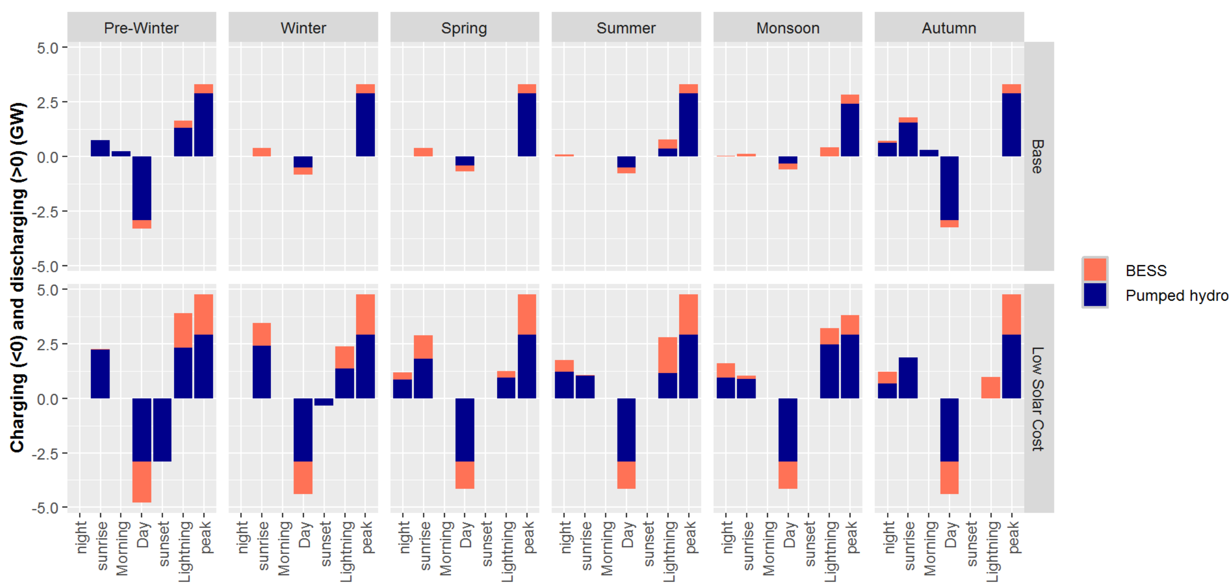

Figure 23. Comparison of storage operations in the Base and Low Solar cost scenarios in 2030

This scenario reveals that if solar costs decline faster than anticipated there could be an increased role for energy storage to match generation from variable RE to electricity demand in the Tamil Nadu power system. Despite the change in Tamil Nadu's capacity and generation mix, other results remained relatively constant compared to the Base scenario. No new transmission investments are added, and the level of imports in 2030 is relatively unchanged.

8.2.2 High RE Target

The **High RE Target** scenario examines a future with more ambitious 2030 policy targets for RE. The new targets are 18.6 GW for solar PV and 20 GW for wind, up from targets of 11 GW and 13 GW. Wind investments continue to be economic beyond this advanced target, reaching 22 GW by 2030. Investments in solar PV are added only up to the 18.6 GW target, indicating this level of solar would not otherwise be built under current cost and demand projections. Increased solar capacity also leads to increased investments in flexible BESS and gas CC resources, able to ramp up or down quickly throughout the day. By 2030, BESS and gas CC capacity reach 0.8 GW and 8 GW, respectively. Figure 24 compares the time-slice generation for the Base and High RE Target scenarios in 2030.

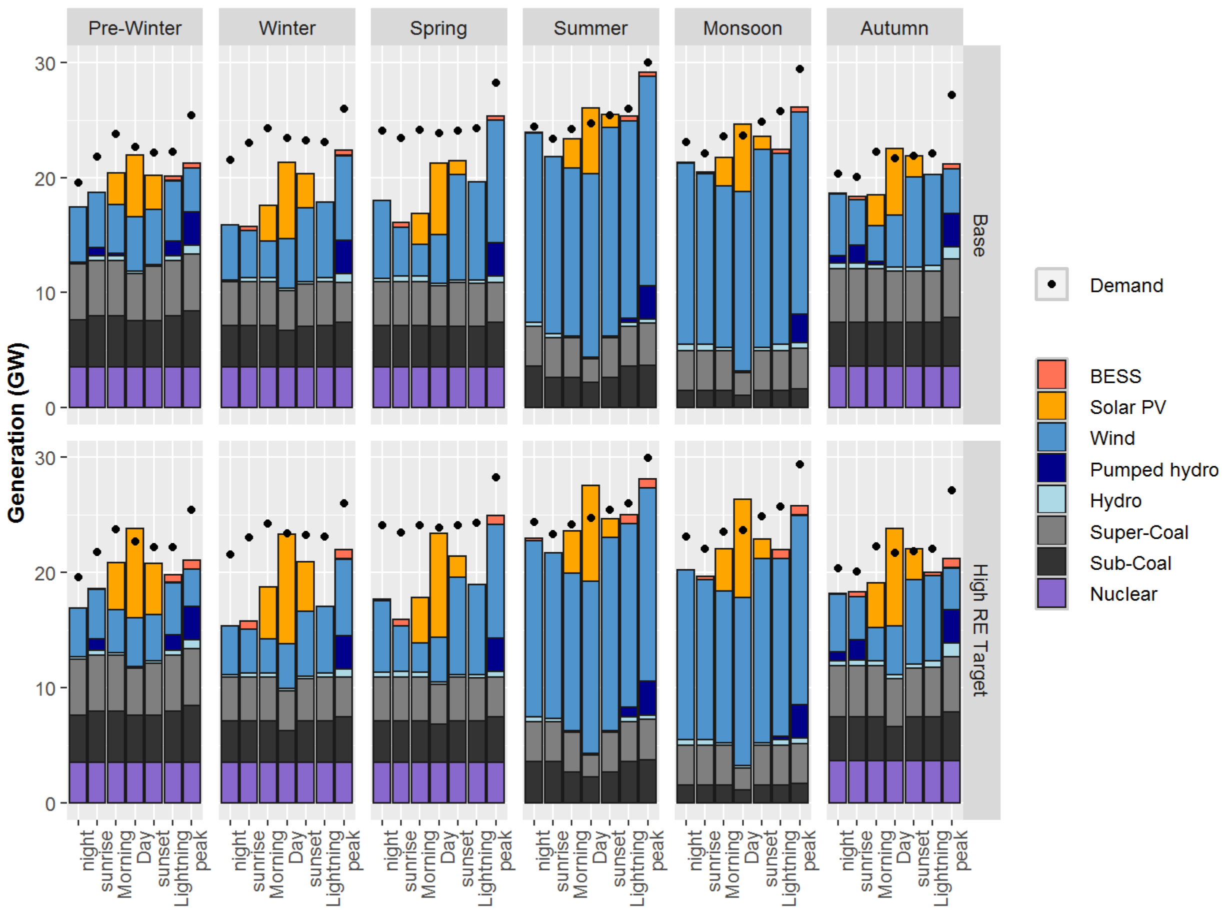

Figure 24. Time-slice generation in the Base and High RE Target scenarios for 2030

The High RE Target scenario does not significantly impact system operations. The combined share of wind and solar in the state's generation mix is largely unchanged at 53%, compared to 52% in the Base scenario. The share of demand met by imports from neighboring states, RE curtailment, and transmission flows are also unchanged compared to the Base scenario.

Increased generation capacity in the High RE Target scenario results in higher costs compared to the Base scenario. Capital costs for new capacity increase by ₹ 26,700 crore, including an additional ₹ 13,300 crore for increased solar PV capacity. Variable costs fall slightly (<1%) but these savings are small compared to the increase in capital costs. Total costs are 11% higher than in the Base scenario.

It is notable that the Low Solar Cost scenario achieves almost the same level of RE investment (16 GW solar PV and 22 GW wind) as the High RE Target scenario. This suggests reducing the cost of solar PV could be an alternative path to increate RE penetration in Tamil Nadu.

8.2.3 Responsive Demand

The **Responsive Demand scenario** investigates the impact of potential demand response programs that result in time-shifting of load from peak demand hours to other times of day. We assume peak demand is reduced by 10% and the reduced energy is spread across other non-peak time-slices such that the total annual energy demand remains unchanged. Figure 25 illustrates how the Responsive Demand scenario impacts Tamil Nadu's hourly load for the five highest load days in 2030.

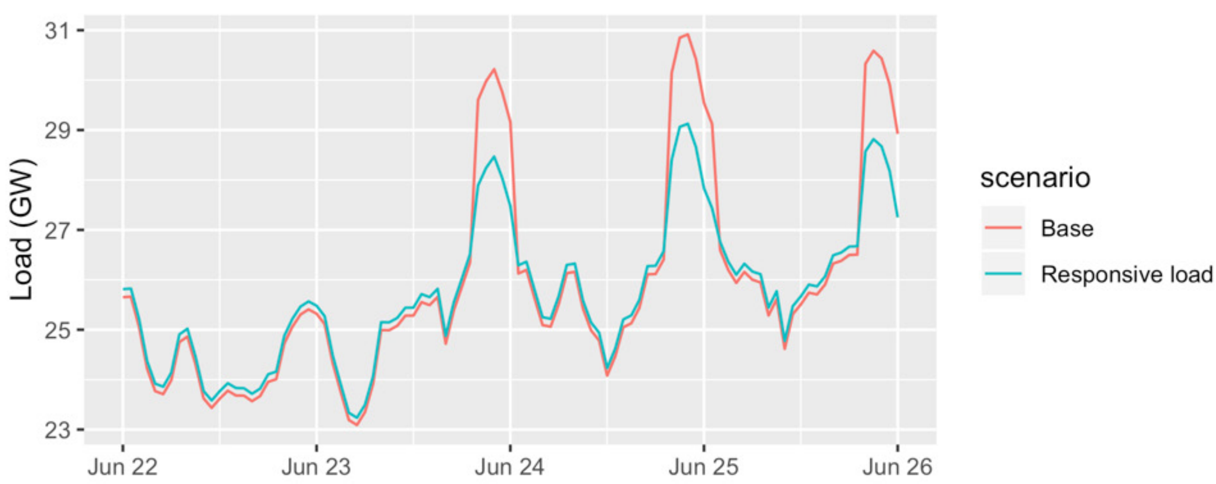

Figure 25. Hourly load profile in the Base and Responsive Demand scenarios for the highest load days in 2030

Shifting electricity demand from peak periods to nonpeak periods "flattens" the demand profile with smaller differences in peak and off-peak demand. This flatter demand profile increases the economic feasibility of wind because, when aggregated to the state level, wind is generally available throughout the day. As a result, investments in wind increase 2.2 GW compared to the Base scenario.

By 2030, Tamil Nadu is expected to have 2.9 GW of pumped hydro capacity in all scenarios. Responsive demand reduces the need for additional energy storage investments to shift generation from low demand periods to high demand periods. For example, over the model period, 988 GWh of RE generation is curtailed in the Base scenario. In the Responsive Demand scenario, total RE curtailment falls by 58% to 415 GWh. Investments in BESS decrease from 300 MW in the Base scenario to 74 MW. This analysis focuses on the ability of BESS to provide energy arbitrage, operating reserves, and contribute to the planning reserve margin. BESS may still be economic for providing other services (e.g., voltage support, frequency regulation, backup power) outside the scope of this analysis.

8.2.4 New Gas

In the **New Gas** scenario, we assume increased import terminals result in more gas available for electricity production in future years. We assume gas prices will remain constant, compared to the Base scenario, as the cost of new infrastructure to enable fuel delivery is assumed to be reflected in the plants' delivered fuel costs. Nationally, additional gas supplies increase use of gas CC technologies delaying investments in gas CT in early model years. Fewer gas CT investments in early years limits investments in this technology in later years through the relative growth limit. The effect of this constraint in Tamil Nadu is investments in gas CC over gas CT. Despite these changes and increased gas supply, we do not see significant changes in Tamil Nadu's generation mix by 2030. The high cost of gas plant operation results in 88% of gas fuel available for the power sector to remain unused in the New Gas scenario. This suggests the future of gas for electricity production in India is less constrained by fuel availability than by cost-competitiveness with other technologies.

9 Conclusion

The supply of electricity in Tamil Nadu is poised to undergo significant changes by 2030. State capacity targets and competitive technology costs drive investments in wind, solar, and BESS, while investments in coal, hydropower, and nuclear capacity are limited to committed projects already underway. Investments in wind and solar could be economic beyond the levels currently anticipated for state targets.

The results from this type of long-term assessment are pertinent for a range of decision makers. Policymakers must establish the policy and regulatory frameworks necessary to enable cost-effective investments and system operations. The results can allow utilities, project developers, and financing institutions to anticipate system changes and mobilize necessary expertise and capital to realize the long-term vision. Finally, the evolution of the power system is of interest to the broader public, who will be impacted by issues related to land use, electricity prices, quality of supply, emissions, and domestic jobs in the energy sector.

A number of insights from this study can help inform planning processes and decisions that may increase Tamil Nadu's capability to efficiently plan the power system in a way that is consistent with national and state goals for RE deployment, reliability, and cost-effectiveness.

- Investments in wind, solar PV, and battery storage are anticipated to be competitive with thermal capacity by 2030. The least-cost mix of generation resources includes 34 GW of wind and solar PV capacity, accounting for 52% of annual generation by 2030.

- Increased deployment of solar PV beyond current ambitions may require further public support. Two mechanisms tested here, decreasing the capital cost for solar PV and increasing state policy targets, resulted in increased investments in solar PV and battery energy storage. Absent those mechanisms, solar is not built beyond the existing target.

- Programs to support time-shifting of load from peak to off-peak hours can further support the integration of RE by reducing total curtailment and the need for investments in flexible resources. An area for future work is to investigate the impact of specific programs or policies or seek to determine the optimal level of demand shifting.

- Investments in battery energy storage are increasingly economic, given that policy and regulatory frameworks are in place to allow these technologies to shift energy from periods of low demand to periods of high demand. We did not evaluate the full range of potential services that battery storage could provide, such as voltage and frequency support and backup power. Enabling policy and regulatory frameworks could increase the viability of battery storage if they are allowed to earn revenue from these services as well.

- Modernized planning to ensure resource adequacy includes consideration of the interactions between RE and demand, rather than peak demand alone. It also requires careful assessment of the contribution of solar, wind, and energy storage technologies to resource adequacy requirements. This study does not evaluate the appropriate level of reserve requirements; this is an area for future work to ensure capacity investments align with anticipated needs.

As Tamil Nadu and the Government of India continue to pursue more ambitious power sector transformation goals, system planners must consider how to shape the trajectory of the state's power system, given the confluence of technology, cost, reliability, and policy factors. The data collection and model design processes undertaken for the study provide a framework for recurring planning studies.

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