TAMIL NADUELECTRICITY REGULATORY COMMISSION

EXPLANATORY MEMORANDUM (EM)

On

Draft Tamil Nadu Electricity Regulatory Commission (Framework for Resource Adequacy) Regulations, 2024

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Abbreviations

AT&C	:	Aggregate Technical & Commercial
CEA	:	Central Electricity Authority
CERC	:	Central Electricity Regulatory Commission
CPD	:	Coincident Peak Demand
DER	:	Distributed Energy Resources
DL	:	Distribution Licensee
EM	:	Explanatory Memorandum
ENS	:	Energy Not Served
EV	:	Electric Vehicle
FoR	:	Forum of Regulators
FY	:	Financial Year
GW	:	Gigawatt
IEGC	:	Indian Electricity Grid Code
kW	:	Kilowatt
LDC	:	Load Duration Curve
LOLP	:	Loss of Load Probability
LT	:	Long-Term
LT-DRAP	:	Long-Term Distribution Resource Adequacy Plan
MoP	:	Ministry of Power
MT	:	Medium-Term
MT-DRAP	:	Medium-Term Distribution Resource Adequacy Plan
MU	:	Million Units
MW	:	Megawatt
MWh	:	Megawatt-Hour
NCPD	:	Non-Coincident Peak Demand
NENS	:	Normalised Energy Not Served
NEP	:	National Electricity Plan
OA	:	Open Access
PLF	:	Plant Load Factor
PRM	:	Planning Reserve Margin
RE	:	Renewable Energy
RPO	:	Renewable Purchase Obligation
SERC	:	State Electricity Regulatory Commission
SLDC	:	State Load Despatch Centre
ST	:	Short-Term
ST-DRAP	:	Short-Term Distribution Resource Adequacy Plan
STU	:	State Transmission Utility
TNPDCL	:	Tamil Nadu Power Distribution Corporation Ltd
TNERC	:	Tamil Nadu Electricity Regulatory Commission

Introduction

Tamil Nadu's peak demand and energy requirement are projected to grow over the next few years. On the supply side, share of renewable energy (RE) in its installed capacity has grown by65% in FY23 (18.4 GW) as compared to FY18 (11.2 GW), and accounting for the 3rdhighest RE installed capacity in India. The RE capacity in Tamil Nadu contributes nearly 24% of the total power generation and it is amongst the leading states in the renewable energy sector in the country.The state could add 25 GW of Wind Power Capacity by 2030 (as per Global Wind Energy Council report). This will further entail a rapid expansion from the current 7.4 GWs of solar and 10.4 GWs of wind.

As it embarks on this transition, the electricity sector faces several challenges, such as the treatment of RE capacity to meet peak load and increased system ramping and balancing needs. Hence, a cost-effective approach to meet forecasted demand at all times with a mechanism of sharing of resource among distribution licensee (DL) and states to maximise utilisation is required for a systematic Resource Adequacy (RA) framework. Having a well-designed RA framework would be important to scale up renewables in the grid while ensuring grid reliability in a cost-effective manner.

RA entails the planning of generation and transmission resources for reliably meeting the projected demand in compliance with specified reliability standards for serving the load with optimum generation mix. This would also facilitate the scaling of RE while considering the need, inter alia, for flexible resources, storage systems for energy shift, and demand response measures for managing the intermittency and variability of renewable energy sources. RA analysis provides the tools to determine whether there are enough resources and, if not, what type of resource is needed to meet reliability needs and contract these capacities. At the same time, any surplus resulting in the analysis would facilitate the trading of the same with other constituents ensuring optimal capacity utilisation.

Existing Institutional Frameworks

In December 2022, the Ministry of Power (MoP) notified the Electricity Amendment Rules stated that the State Electricity Regulatory Commission (SERC)would frame RA Regulations in accordance with Guidelines issued by the Central Government and State Model Regulations by the Forum of Regulators (FoR). It further stated that distribution licensee (DL) would formulate RA plans in accordance with SERC Regulations, while State Load Despatch Centre (SLDC) would carry out state-level assessments. The non-compliance charges would be determined by the SERC.

In May 2023, the Central Electricity Regulatory Commission (CERC) notified the Indian Electricity Grid Code, 2023 (IEGC 2023) which stated that integrated resource planning would consist of demand forecasting, generation resource adequacy planning, and transmission resource adequacy assessment.

Subsequently in June 2023, the Central Electricity Regulatory Authority (CEA) published the Guidelines for Resource Adequacy Planning Framework in India which outlined the reliability standards and methodologies involved in RA planning and assessment.

The FoR has since published its State Model Regulations for Resource Adequacy, in which the following four key aspects of RA framework are highlighted:

1. Demand assessment and forecasting
2. Generation resource planning
3. Procurement planning
4. Monitoring and compliance

The Draft TNERC (Framework for Resource Adequacy) Regulations, 2024 (Draft RA Regulations) should be read along with the present Draft Explanatory Memorandum (EM) as the Commission, after

duly considering the comments/suggestions received from stakeholders, may consider incorporating various requirements laid down under the present EM. The EM is organized in the following Section:

Section 1: Demand Assessment and Forecasting

Section 2: Generation Resource Planning

a) Capacity Crediting
b) Planning Reserve Margin
c) RA Requirement and Allocation

Section 3: Procurement Planning

a) Procurement Resource Mix
b) Procurement Type and Tenure
c) Capacity Trading/Sharing

Section 4: Monitoring and Compliance

1. Demand Assessment and Forecasting

This chapter of the EM elaborates the reasoning and justification for fundamentally shifting the present demand assessment and forecasting to a scientific and mathematically driven one.

Demand assessment and forecasting is the first and most crucial step of any RA planning analysis. It involves forecasting of peak (MWs) and energy (MUs) requirement for multiple horizons (short/medium/long-term) and considers various input parameters such as historical consumption, consumer categories, weather data, econometric data, policies and drivers, etc. Long-term (LT) demand forecasting is typically undertaken to economically plan the new generating capacity and transmission networks over 10-20 years. Medium-term (MT) demand forecasting is undertaken for scheduling of fuel supplies, maintenance programs, financial planning, and tariff formulation for up to 5 years. Short-term (ST) demand forecasting is for planning start-up and shut-down schedules of generating units, reserve planning, and the study of transmission constraints over 1 day up to 1 year.

It is required to adopt a scientific approach at an hourly granularity that helps identify overall resource requirement to meet demand with minimal cost implications in terms of optimal capacity planning without compromising on reliability and at the same time without excess or deficit capacity. It is also critical to consider various demand drivers such as electric vehicles (EVs), distributed energy resources (DERs), changes in weather conditions etc.

Considering Regulation 6 of the Draft RA Regulations, the DL should adopt the following methodology for demand assessment and forecasting under RA:

Figure 1: Demand Assessment and Forecasting Methodology

DL may consider the latest Electric Power Survey (EPS) report or its own updated forecast following the scientific approach as base and customize it with additional inputs, consumption profiles, and various policies and drivers pertaining to its control area.

1. Additional inputs such as consumer data, historical demand data, weather data, demographic and econometric variables, T&D losses, actual electrical energy requirement and availability including curtailment, peak electricity demand, and peak met along with changes in demand profile (e.g.: agricultural shift, time of use, etc.), historical hourly load shape, etc. should be considered.
2. Consumption profiles for each class of consumers, such as domestic, commercial, public lighting, public water works, irrigation, LT industries, HT industries, railway traction, bulk (non-industrial HT consumers), open access, captive power plants, insights from load survey, contribution of consumer category to peak demand, seasonal variation aspects, etc. should be considered.
3. DL while assessing demand should consider DSM measures such as energy efficiency, energy savings and conservation, demand response programs etc.
4. Various policies and drivers such as LED penetration, efficient fan penetration, appliance penetration, increased usage of electrical appliances for cooking, etc., in households, increase

in commercial activities, increase in number of agricultural pumps and solarization, changes in specific energy consumption, consumption pattern from seasonal consumers such as tea plants, Demand side management measures (DSM), Distribution Energy Resources (DERs), e-mobility (EVs) and green energy open access (GEOA), National Hydrogen Mission, reduction of AT&C losses, etc. should be considered.

5. Further, while undertaking demand forecasts, the distribution licensee shall take into consideration the impact and benefits arising out of the demand side management programmes and DSM plans, energy efficiency measures, energy conservation interventions in pursuance of Tamil Nadu Electricity Regulatory Commission (Demand Side Management) Regulations, 2013 and amendments thereof.

Based on the collection of comprehensive inputs, DL should apply scientific and mathematical methodologies with best fit to forecast demand at minimum hourly granularity and for a 1-year and a 5-year period. State Transmission Utility (STU) and SLDC will then compile comprehensive inputs received from all DL and independently create a state-level demand forecast with minimum hourly granularity and for a 1-year and a 5-year period.

2. Generation Resource Planning

This chapter of the EM elaborates the key steps involved in generation resource planning, viz., capacity crediting, planning reserve margin, and RA requirement and allocation, along with explanation of how to compute each step.

Capacity Crediting

The Capacity Credit (CC) of a generating technology represents the amount of power it can reliably provide.[1] The capacity credit is measured either in terms of physical capacity (kW, MW, or GW) or the fraction of its nameplate capacity (%).Capacity crediting (CC) ensures that the generation resources are available for meeting the demand at any point in time even with generation outages and variability in generation. It also helps in displacing the need to build new resources and encourages to use existing resources optimally. The CC of energy resources is particularly important in long-term utility planning. It can be one of the key assumptions affecting resource selection in the capacity expansion models frequently used in integrated resource planning.[2]

In the "Top Net Load Hours" methodology, it is considered that the system is under stress when high demand coincides with low renewable energy generation. 'Net load' is defined as 'total renewable energy generation subtracted from overall demand', which must be met from dispatchable resources like thermal plants, hydro plants, etc. Due to system stress caused by the duck curve, the net load could bea better proxy for system stress for new capacities than peak demand. The capacity credit can be obtained by averaging the contribution of a generator/generator class during top net load hours. Similar to the previous method, the selection of a number of top net load hours varies across geographies.

As part of the Regulation 10 of the Draft RA Regulations, DL/state should adopt the following steps to compute CC factors for various resources in their control area:

1. For each year, the load is arranged in descending order.
2. For each hour, the net load is calculated by subtracting the solar or wind generation corresponding to that load and then arranged in descending order similar to Step 1 (load duration curve i.e. LDC for FY23 is shown in Figure 2 below).
3. The difference between these two load duration curves represents the contribution of solar and wind generation.
4. Installed capacity is summed up corresponding to the top 250 hours.
5. Total solar or wind generation is summed up corresponding to the top 250 hours.
6. Resultant CC is (Total Generation)/(Installed Capacity) for the top 250 hours (calculation for FY23 shown in Table 1 below).

$$\text{CC factor} = \frac{\text{Total Generation for top } x \text{ hours}}{\text{Total Capacity for top } x \text{ hours}}$$

This process should be done for each year and the resultant CC should be calculated as the average of CC values of the recent 5 years. Taking average of 5 recent years ensures that impact of changes in installed capacities, demand profile, and generation profile on CC is duly factored.

The following input data should be used:

[1] Draft Guidelines for Resource Adequacy Planning Framework for India, CEA, September 2022.

[2] Drivers of the Resource Adequacy Contribution of Solar and Storage for Florida Municipal Utilities, LBNL,2019 10 24.

1. Annual peak (MW) and energy (MWh) projections of the next five years.
2. Hourly load profile (MWh) of the recent 5 years.
3. Hourly generation profile of solar, wind, and hydro resources of the recent five years.
4. At least hourly, or else monthly, installed capacities of solar, wind, and hydro resources in-line with generation profile provided in point no. 3.
5. Availability factors for thermal and gas resources.

The CC factors should be such that contributions of inter-state and intra-state RE generators contracted by the distribution licenseeis considered. There need not be a separate methodology for imports or existing/new resources.CC for hydro resources should be computed based on water availability. CC factors for run-of-the-river hydro power projects should be different from those of dam-based/storage-based hydro power projects, with due consideration of the design and operational experience of such projects. CC for thermal resources should be computed based on coal availability and planned outages.

DL and SLDC should compute CC factors for their control areas and use them in their assessment of supply availability.

The following figure shows preliminary and illustrative LDCs of gross load and net load for FY23, as explained in step 2 of the methodology above:

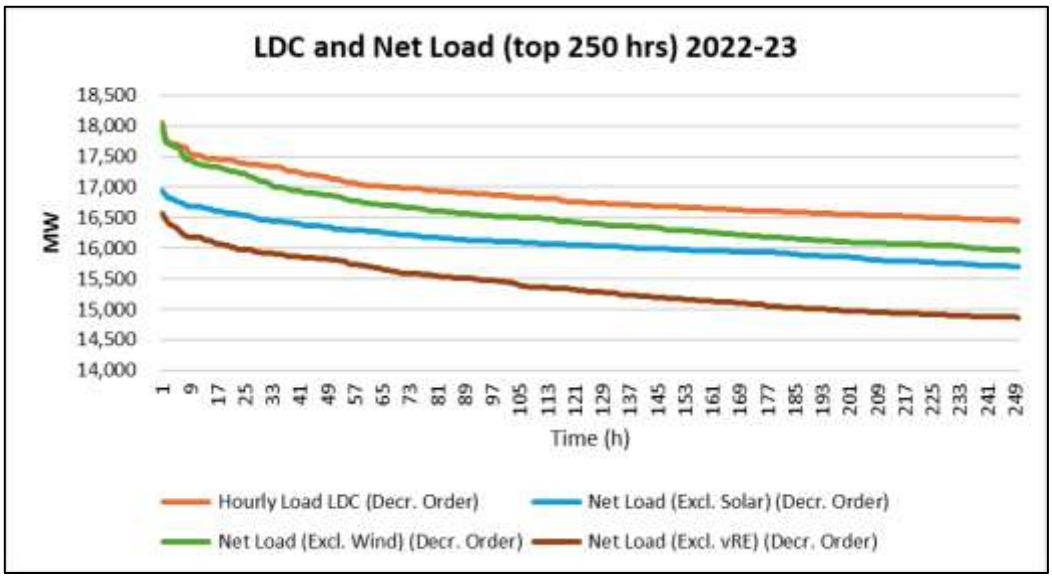

Figure 2: Load Duration Curve of Gross load and Net load for FY23

From the LDC and net LDCs, it can be seen that contribution of solar is higher than that of wind, indicating a higher CC for solar than for wind.

Once LDC and net LDCs are plotted, steps 4 to 6 of the above methodology should be adopted. Accordingly, the summation of installed capacity and generation for top 250 hours followed by calculation of CC factors is shown in table below, both for FY23 as well as average of previous five years.

Table 1: CC calculation for FY23 and 5-year average

	FY23 IC based Gen for top 250 Hrs (MWh) (A)	**FY23 Generation during top 250 Net Load Hours (MWh) (B)**	**FY23 CC (%) C = B/A (C)**	**5-yr Avg. CC**

Solar	17,17,333	1,88,472	10.97%	8.97%
Wind	21,84,753	86,893	3.98%	3.83%
vRE	39,02,085	3,67,472	9.42%	8.00%

Preliminary and illustrative historical CC factors are shown in the Figure below:

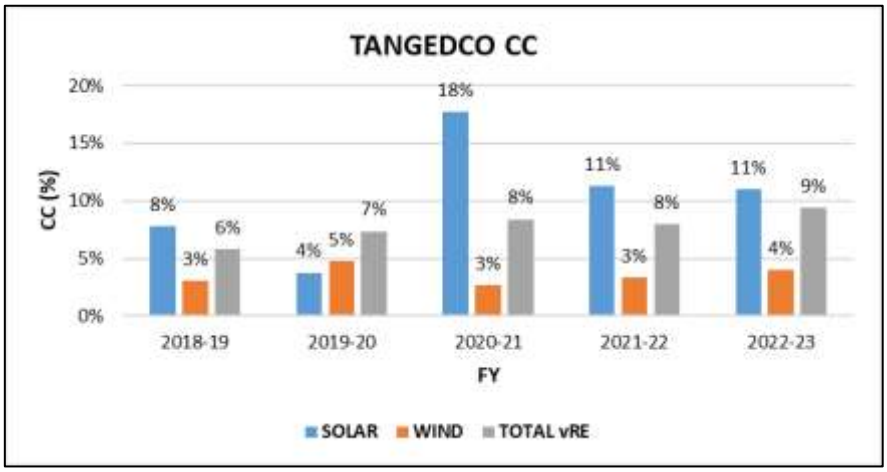

Figure 3: Illustrative CC Factors

Preliminary insights on CC factor:

- Solar CC is mostly higher than wind CC.
- CC factor for wind varies from 3-5% while for solar it varies from 4-18%
- CC factor for wind and solar presents varying trend over 5-year period.
- Composite CC factor for VRE is in the range of 6-9%.

These numbers are computed based on available data and for illustration and discussion purposes. They may change with change in input assumptions.

Planning Reserve Margin

Planning Reserve Margin (PRM) is a certain percentage of the projected capacity resources available in the system over the projected peak load forecast of the system and is used to ensure the resource adequacy of the system. It is the amount of resource capacity required to meet the reliability targets such as loss of load probability (LOLP) and Normalised Energy Not Served (NENS) while making sure peak demand is met all the time. It is a predominant matrix used to ensure adequacy in the power system.

Loss of Load Probability (LOLP) and Energy Not Served (ENS) are key factors that go into the determination of PRM. CEA's Draft Resource Adequacy Guidelines define LOLP as the *"measure of the probability that a system's load will exceed the generation and firm power contracts available to meet that load in a year. E.g., 0.0274% probability of load being lost"*. The Guidelines define ENS as the *"expected amount of load (MWh) that may not be served for each year within the planning period. It is a summation of the expected number of megawatt hours of demand that may not be served for the year because of demand exceeding the available capacity…the metric can be normalized (i.e., divided by total system load) to create a Normalized Energy Not Served (NENS)"*.

As part of Regulation 11 of the Draft RA Regulations, DL and STU/SLDC should either adopt the PRM as notified by CEA or compute their own such that it is at least equal to or greater than the PRM notified by CEA. The PRM should be such that load generation profile is duly factored and LOLP and ENS parameters are met.

RA Requirement and Allocation

Based on assessment and forecasting of demand, application of PRM,and application of CC factors to installed capacity, the incremental capacity needed to meet RA requirement for the DL/state should be identified. This would involve the identification of capacity required to reliably meet demand plus PRM, considering available capacity adjusted for capacity crediting. After computing RA requirement for the state, it should then be allocated further to DL. Here, since the state has only one DL, TANGEDCO will be allocated 100% of the state's RA Requirement. In case of multiple DLs, there are two methods for allocating the state RA requirement down to DLs, one based on percentage share ofDL in state coincident peak demand (CPD) plus PRM, and the other based on average of percentage share of DL in state CPD plus PRM and percentage share of DL in state non-coincident peak demand (NCPD) plus PRM. The second method ensures appropriate and optimal requirement and allocation of resources while also ensuring that the DL is able to meet its own peak plus PRM i.e. NCPD.

As part of the Regulation 12 of the Draft RA Regulations, the following steps should be taken to arrive at RA requirement for state and allocation down to DLs:

1. Discount state installed capacity by CC to arrive at actual available capacity for state.
2. Subtract that from the state demand plus PRM to arrive at resource gap for the state.
3. Allocate this resource gap to DLs based on average of percentage share of DL in state CPD plus PRM and percentage share of DL in state NCPD plus PRM.

Illustrative and preliminary numbers adopting the above methodology are as follows:

Following chart shows the YoY surplus/deficit capacity for Tamil Nadu:

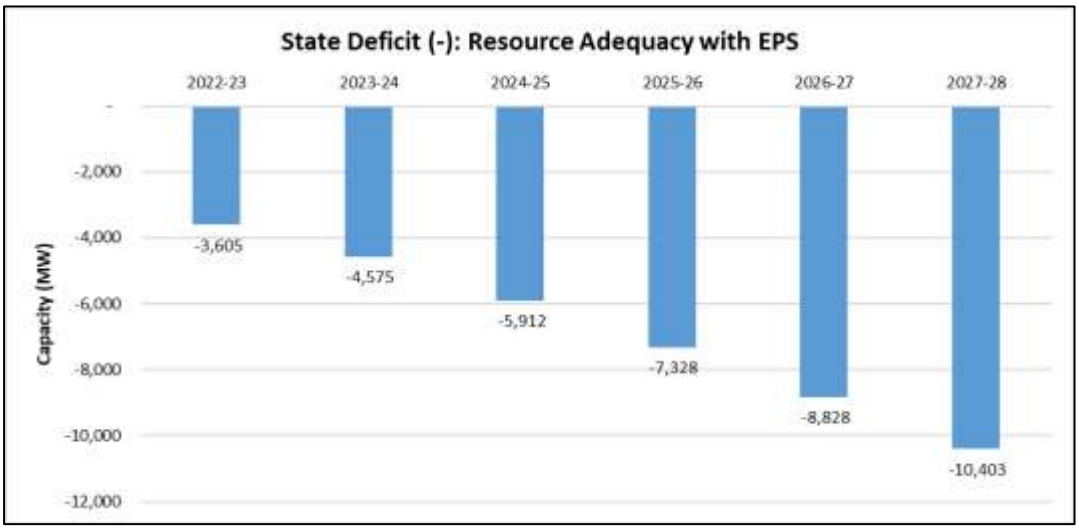

Figure 4 Preliminary Identification of RA Requirement

It can be seen that the state is in deficit starting from FY23 and the quantum of deficit increases over the horizon, reaching up to 10.4 GW of deficit capacity by FY28.

However, these numbers are computed basis of existing installed capacity of FY23. The RA requirement may change/reduce once recent contracted/commissioned capacity is accurately factored.

As the state is in a deficit of 3,605 MW in FY23, the same is allocated to DL (100%) based on its full share in the state peak with PRM. Similarly, TANGEDCO will be allocated the complete state capacity requirement of 10,403 MW in FY28.

3. Procurement Planning

This chapter of the EM elaborates the key steps involved in procurement planning, viz., procurement resource mix, procurement type and tenure, and capacity trading/sharing.

Procurement Resource Mix

Based on computation of RA requirement and its allocation, an optimal generation capacity resource mix should be computed such that it can fulfill the requirements in a least-cost manner while maintaining reliability standards. The resource mix should be such that it enables smooth RE integration and can contribute towards RPO and other targets.

Least-cost optimization is a highly extensive and involved process. Energy modelling involves system representation through input parameters such as demand forecasts and hourly profiles, technical and financial characteristics of all generators in the system, information on retiring and contracted capacity, fuel costs, economic assumptions, transmission links, constraints, etc. Capacity expansion is then carried out for the necessary time horizon which results in economic retirements and additions of power plants for meeting demand requirement. Typically, this is followed by a granular dispatch of the new resource mix to get insights on hourly load-generation balance, performance of certain technologies such as storage, reliability standards, unserved energy, dump energy, and cost of generation as well as total system cost. At the base of this setup is a mathematical model that conducts iterations and uncertainty analysis to arrive at the optimal solution.

The National Electricity Plan, 2023 (NEP)[3] has undertaken generation resource planning by considering technical and financial characteristics of various types of resources such as coal, gas, nuclear, hydro, wind, biomass, solar, BESS, PSH etc. and by using ORDENA and PLEXOS software tools. It describes the following to be key aspects of generation resource planning:

1. Achieving objectives of all Government policies
2. Achieving sustainable development
3. Fulfilling desired operational characteristics of the system such as reliability and flexibility
4. Ensuring most efficient use of resources
5. Factoring fuel availability

Key inputs to the model are as follows:

1. Demand:
    a. Annual peak and energy requirement projections for the next five years

[3] National Electricity Plan, 2023, CEA

b. Hourly profile for the previous five years

2. Generation:

    a. Resource-wise generators with their technical characteristics such as installed capacity, heat rates, ramp rates, capacity utilization factors, maintenance rates, forced outage rates and financial characteristics such as capital costs, variable and fixed costs etc.

    b. Hourly generation profile for solar, wind, and hydro resources for the recent five years.

With reference to Regulation 14 of the Draft RA Regulations, the distribution licensee should undertake such energy modelling exercises to compute the least-cost resource mix to meet their allocated RA requirement.

Procurement Type and Tenure

Based on the optimal resource mix for meeting RA requirement allocation, the timeline of capacity procurement (MT/ST) and capacity quantum across the planning horizon should be determined. DL should plan how much capacity they need to procure/contract in what timeframe (MT/ST) to comply with the resource adequacy requirement. Information regarding the capacity surplus/deficit is required for deciding the amount of capacity the states are supposed to procure either medium term (MT) through a competitive bidding process or short-term capacity trading/sharing.

Considering Regulation 15 of the Draft RARegulations, DL should identify the generation resource mix and also procurement strategy over the planning horizon and seek approval of the Commission.

Capacity Trading/Sharing

There is benefit to RA planning at the state level by means of sharing excess capacity with DLs and other states in deficit. Currently, India's short-term market is purely an energy-only market. In mid- and long-term markets, investment in building capacity is recovered through fixed charges which are recoverable at the normative level of PLF with incentives for higher PLF. The buyer is bound to consume energy from the contracted capacities. However, there is a huge liability for the buyer to pay a high fixed charge over a 25-year PPA period and sometimes consume out-of-merit energy. With an increase in RE penetration, power producers have been finding it difficult to sustain stable operations due to the reduction of PLFs. There is no incentive available for them to set up new capacities and operate the existing ones. Capacity sharing would enable stakeholders to optimize costs and increase the reliability of operations.

Considering Regulation 16 of the Draft RA Regulations, DL should duly factor in the possibility of short-term capacity sharing while preparing the Resource Adequacy plan and optimally utilize the capacity available within the state through arrangements or other mechanisms in compliance with competitive bidding guidelines, and then use the platform for inter-state capacity sharing or trading mechanism if created by the Central Commission or other mechanisms as the case may be and optimize the capacity costs as far as possible.

4. Monitoring and Compliance

This chapter of the EM elaborates the timelines and implementation mechanisms related to monitoring and compliance of the Draft RA Regulations in the state.

Monitoring and compliance is necessary to ensure that RA requirements are met on a continuous basis. The timeline should be compliant with national RA planning as well as state MYT Regulations and procurement.The Commission should duly incentivize/penalize stakeholders based on performance and RA compliance, as the case may be.

Considering Regulation 19 of the Draft RA Regulations, the following timelines should be followed:

1. DL should conduct demand forecasting by 30th April of the applicable year.
2. STU/SLDC should conduct demand forecasting by 31st May of the applicable year.
3. Based on allocation of RA requirement to state from national planning, DL should perform medium-term RA planning (MT-DRAP) and SLDC should perform short-term RA planning (ST-DRAP) by 31st August of the applicable year.
4. STU and TNSLDC shall communicate the state-aggregated capacity shortfall to the Commission by 15th September of each year.
5. Commission should approve RA plans by 30th September of the applicable year.
6. DL should contract capacities by 30th November of the applicable year.
7. DL should submit contracted capacities and compliance verification by 31st December of the applicable year.
8. STU/SLDC should submit state-level RA plans by 31st January of next year.
9. Based on national RA compliance verification, shortfall will be communicated to STU/SLDC for further action by STU/SLDC and DL by 31st March of the next year.

The rate of Non-compliance charges shall be equivalent to 1.1 times the Marginal Capacity Charge (Rs/kW/month) or 1.25 times the Average Capacity Charge (Rs/kW/month) whichever is higher, as approved by the Commission for the power procurement by concerned distribution licensee under its ARR/Tariff Order for the relevant financial year, unless separately specified by the Commission.

Process flow chart in line with national framework is shown below:

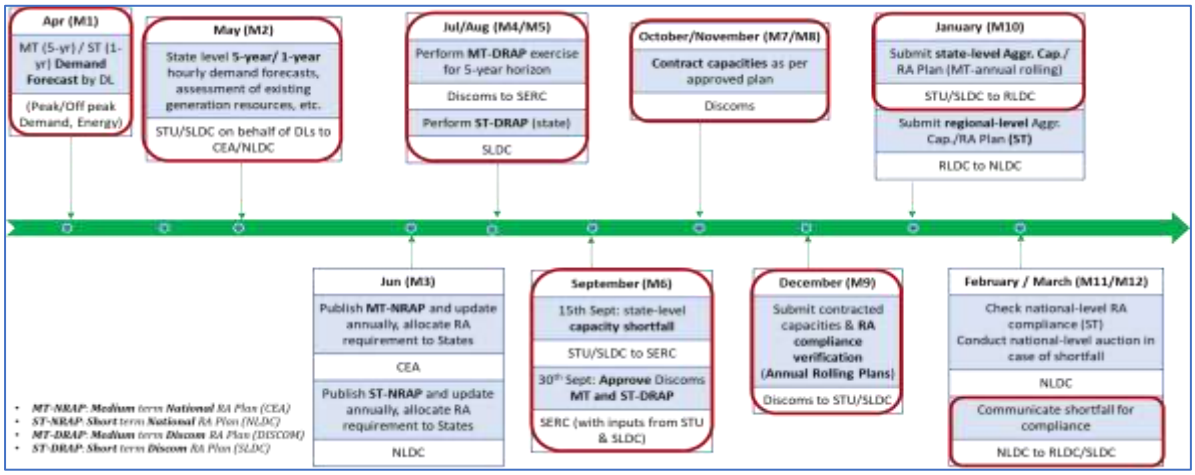

Figure 5 Process Flowchart for RA Planning

(By order of the Commission)

Sd/- dated 13-06-2024

(Secretary)

Tamil Nadu Electricity Regulatory Commission

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Draft Notification No. TNERC/RA/ …… dated 13-06-2024
(Comments/suggestions are invited on or before 05-07-2024)

DRAFT TAMIL NADU ELECTRICITY REGULATORY COMMISSION (FRAMEWORK FOR RESOURCE ADEQUACY) REGULATIONS, 2024

NOTIFICATION

The following draft of the Tamil Nadu Electricity Regulatory Commission (Framework for Resource Adequacy) Regulations, 2024 which is proposed to be issued in exercise of the powers conferred under section 181 of the Electricity Act, 2003 (36 of 2003), read with sections 61, 66, and 86 thereof and all other powers enabling it in this behalf is hereby published for information of all persons likely to be affected thereby, as required under subsection (3) of section 181 of the Electricity Act, 2003.

2. Notice is hereby given that the draft Regulations will be taken into consideration after the expiry of thirty days from the date of publication of this notification in the TNERC website and that any objection or suggestion, which may be received from any person before the expiry of the aforesaid period, will be considered by the Commission.

3. Objection or suggestion, if any, should be addressed in duplicate to the Secretary, Tamil Nadu Electricity Regulatory Commission, 4th floor, SIDCO Corporate Office Building, Thiru-Vi-Ka Industrial Estate, Guindy, Chennai – 600 032.

Chapter 1
Preliminary

1. Short Title, Extent, and Commencement

1.1. These Regulations shall be called the Tamil Nadu Electricity Regulatory Commission (Framework for Resource Adequacy) Regulations, 2024.

1.2. These Regulations shall extend to the whole of Tamil Nadu.

1.3. These Regulations shall come into force from the date of publication in the Tamil Nadu Government Gazette.

2. Objective

2.1. The objective of these Regulations is to enable the implementation of Resource Adequacy framework by outlining a mechanism for planning of generation and transmission resources for reliably meeting the projected

demand in compliance with specified reliability standards for serving the load with an optimum generation mix.

2.2. The Resource Adequacy framework shall cover a mechanism for demand assessment and forecasting, generation resource planning, procurement planning, and monitoring and compliance.

3. Scope and Applicability

3.1. These Regulations shall apply to the generating companies, distribution licensee, State Load Despatch Centre, State Transmission Utility, and other grid connected entities and stakeholders within Tamil Nadu.

4. Definitions

4.1. In these Regulations, unless the context otherwise requires,

a. "**Act**" means the Electricity Act, 2003 (36 of 2003) and subsequent amendments thereof.

b. "**Authority**" means Central Electricity Authority referred to in sub-section (1) of Section 70 of the Act.

c. "**Capacity Credit**" or "**CC**" means a percentage of a resource's nameplate capacity that can be counted towards resource adequacy requirements.

d. "**CEA RA Guidelines**" means Guidelines for Resource Adequacy planning framework for India notified by Central Electricity Authority in pursuance of Rule 16 of Electricity (Amendment) Rules, 2022.

e. "**Commission**" or "**State Commission**" means the Tamil Nadu Electricity Regulatory Commission (TNERC) constituted under the Act.

f. "**Distribution Licensee**" means a licensee authorised to operate and maintain a distribution system for supplying electricity to the consumers in his area of supply and TANGEDCO or its successor entity is the Distribution Licensee in the state of Tamil Nadu.

g. "**Expected Energy Not Served**" or "**EENS**" means the expected amount of load (MWh) that may not be served for each year within the time horizon for Resource Adequacy planning.

h. "**Long-Term**" means duration exceeding five years for development of demand forecasting and generation resource planning.

i. "**Long-Term Power Procurement**" means procurement of power under any arrangement or agreement with a term or duration exceeding five years.

j. "**Long-Term National Resource Adequacy Plan**" or "**LT-NRAP**" means plan for national level assessment of long-term resource adequacy published by Central Electricity Authority as per CEA RA Guidelines.

k. "**Loss of Load Probability**" or "**LOLP**" means probability that a system's load will exceed the generation and firm power contracts available to meet that load in a year.

l. "**Tamil Nadu Transmission Corporation Limited**" or "**TANTRANSCO**" means the state transmission utility or **STU**.

m. "**Tamil Nadu State Load Despatch Centre**" or "**TNSLDC**" means the state load despatch centre.

n. "**Medium term**" means five years for development of demand forecast, generation resource plan, and procurement plan.

o. "**Medium-Term Distribution Resource Adequacy Plan**" or "**MT-DRAP**" means plan for assessment of medium-term resource adequacy by the distribution licensee.
p. "**Net Load**" means the load derived upon exclusion of actual generation (MW) from renewable energy generation resources from gross load prevalent on the Grid during any time-block.
q. "**Normalized Energy Not Served**" or "**NENS**" is normalization of the EENS by dividing it by the total system load.
r. "**Planning Reserve Margin**" or "**PRM**" means a specified percentage of available capacity above peak demand as may be stipulated by Authority or Commission for the purpose of generation resource planning.
s. "**Power Exchange**" means any exchange operating as power exchange for electricity in terms of the regulations issued by the Central Electricity Regulatory Commission.
t. "**Power Purchase Agreement (PPA)**" means the agreement entered into between the Procurer(s) and the Seller pursuant to which the Seller shall supply power to the Procurer(s) as per the terms and conditions specified therein.
u. "**Power Sale Agreement (PSA)**" shall mean the back-to-back agreement entered into between the Buying Entity(s) and the Intermediary Procurer/trader for onward sale of power purchased under any power purchase agreement.
v. "**Resource Adequacy**" or "**RA**" means a mechanism to ensure adequate supply of generation to serve expected demand (including peak, off peak and in all operating conditions) reliably in compliance with specified reliability standards for serving the load with an optimum generation mix with a focus on integration of environmentally benign technologies after taking into account the need, inter alia, for flexible resources, storage systems for energy shift, and demand response measures for managing the intermittency and variability of renewable energy sources.
w. "**Short term**" means duration upto one year for development of demand forecast, generation resource plan, and procurement plan.
x. "**Short-Term Distribution Resource Adequacy Plan**" or "**ST-DRAP**" means plan for assessment of short-term resource adequacy by the distribution licensee.
y. "**Short-Term National Resource Adequacy Plan**" or "**ST-NRAP**" means plan for national level assessment of short-term resource adequacy published by Grid India/National Load Despatch Centre as per CEA RA Guidelines.

4.2. All other words and expressions used in these Regulations, although not specifically defined herein above, but defined in the Act, shall have the meaning assigned to them in the Act. The other words and expressions used herein but not specifically defined in these Regulations or in the Act but defined under any law passed by the Parliament applicable to the electricity industry in the State shall have the meaning assigned to them in such law.

Chapter 2
General

5. Resource Adequacy Framework

5.1. Resource Adequacy framework entails the planning of generation and transmission resources for reliably meeting the projected demand in compliance with specified reliability standards for serving the load with an optimum generation mix.

5.2. Resource Adequacy framework shall cover following important steps:

a) Demand assessment and forecasting
b) Generation resource planning
c) Planning of Transmission network augmentation/strengthening
d) Planning of Distribution network augmentation/strengthening
e) Procurement planning
f) Monitoring and compliance

5.3. The medium and short term for the purpose of these Regulations shall be considered as:

a) Medium term procurement plan for a period up to five years; and
b) Short-term procurement plan for a period up to one year.

5.4. The distribution licensee shall develop and prepare Medium-Term Distribution Resource Adequacy Plan (MT-DRAP) and Short-Term Distribution Resource Adequacy Plan (ST-DRAP) in accordance with the conditions outlined under these Regulations.

5.5. The distribution licensee, State Transmission Utility and State Load Despatch Centre shall provide requisite information and data including demand forecasts for period upto 10 years to various Agencies to enable Central Electricity Authority and Grid India/NLDC to undertake LT-NRAP and ST-NRAP studies, respectively, as per CEA RA Guidelines.

Chapter 3
Demand Assessment and Forecasting

6. Long-term and Medium-term Demand Forecast

6.1. Demand assessment and forecasting is an important step for Resource Adequacy assessment. It shall entail at least hourly or sub-hourly as may be decided by the Commission from time to time, assessment and forecastsof demand within the distribution area of distribution licensee for multiple horizons (short/medium/long-term) using comprehensive input data and policies and drivers and scientific mathematical modelling tools.

6.2. The distribution licensee shall be responsible for the assessment and forecasting of demand (MW) and energy (MWh) within its own control area.

6.3. The distribution licensee shall be responsible for providing the category wise consumption data and assessed consumption data of particular class of consumers such as agricultural, domestic etc. to various agencies such as TNSLDC and/or STU for purpose of state level demand forecasts. The distribution licensee shall submit the category wise consumption information of pervious financial years and any other information as may be required by TNSLDC/STU by 21st April of each year as per format to be prescribed by TNSLDC/STU.

6.4. The distribution licensee shall determine the load forecast for each consumer category for which the Commission has determined separate retail tariff.

6.5. The distribution licensee shall determine the load forecast for a customer category by adopting any of the following and/or combination of following methodologies:

a) compounded average growth rate (CAGR);
b) end use or partial end use;
c) trend analysis;
d) Auto-regressive integrated moving average (ARIMA);
e) AI including machine learning, ANN techniques; and
f) econometric (specifying the parameters used, algorithm, and source of data).

6.6. The distribution licensee may use Electric Power Survey (EPS) projections as base and/or any other methodologies other than the above-mentioned after recording the merits of the method. Further, distribution licensee should use best fit of various methodologies for the purpose of demand/load forecast taking into consideration probabilistic modelling approach for various scenarios (viz. most probable, business as usual, aggressive) as outlined under Regulation 6.14.

6.7. For the purposes of deciding the load forecast for a customer category and the methodology to be used for load forecasting of a customer category, the distribution licensee must conduct statistical analysis and shall select the method for which standard deviation is lowest and R-square is highest.

6.8. The distribution licensee shall utilize state-of-the-art tools, scientific and mathematical methodologies, and comprehensive database such as but not limited to weather data, historical data, demographic and econometric data, consumption profiles, impact of policies and drivers etc. as may be applicable to their control area.

6.9. The distribution licensee shall modify the load obtained on either side, for each customer category, by considering the impact for each of the, but not limited to the following activities. The impact shall be considered by developing trajectories for each of the activities based on the economic parameters, policies, historical data, and projections for the future.

a) energy efficiency measures;
b) energy savings and conservation interventions;
c) demand response programs;
d) demand-side management measures;
e) open access;
f) distributed energy resources;
g) DSM;
h) electric vehicles;
i) tariff signals;
j) changes in specific energy consumption,
k) increase in commercial activities with electrification
l) increase in number of agricultural pump sets and its solarization
m) changes in consumption pattern from seasonal consumers

n) availability of supply; and
o) policy influences such as 24X7 supply to all customers, LED penetration, efficient use of fans/appliances, increased use of appliances for cooking/heating applications, electrification policies, distributive energy resources, storage, and policies, which can impact econometric parameters, impact of national hydrogen mission. For each policy, a separate trajectory should be developed for each customer category.

6.10. The distribution licensee shall take into consideration any other factor not mentioned in Regulation 6.8 after recording the merits of its consideration. Further, while undertaking demand forecasts, the distribution licensee shall take into consideration the impact and benefits arising out of the demand side management programmes and DSM plans, energy efficiency measures, energy conservation interventions in pursuance of Tamil Nadu Electricity Regulatory Commission (Demand Side Management) Regulations, 2013and amendments thereof.

6.11. The medium-term load profile of the customer categories for which load research has been conducted may be refined on the basis of load research analysis. A detailed explanation for refinement conducted must be provided.

6.12. The summation of energy forecast (MWh) for various consumer categories upon suitably adjusting for captive, prosumer, and open access load forecast, if necessary, as obtained as per Regulations 6.4 to 6.10, as the case may be, shall be the load forecast for the licensee.

6.13. The distribution licensee shall calculate the load forecasts (in MWh) by adding a loss trajectory approved by the Commission in the latest tariff order. In the absence of the loss trajectory as approved by the Commission for the planning horizon, an appropriate loss trajectory stipulated by State or National policies shall be considered with a detailed explanation.

6.14. The peak demand (in MW) shall be determined by considering the average load factor, load diversity factor, seasonal variation factors for the last three years and the load forecasts (in MWh) obtained in Regulation 6.12. If any other appropriate load factor is considered for future years, a detailed explanation shall be provided.

6.15. The distribution licensee shall conduct sensitivity and probability analysis to determine the most probable demand forecast. The distribution licensee must also develop long-term and medium-term demand forecasts for possible scenarios, while ensuring that at least three different scenarios (most probable, business as usual, and aggressive scenarios) are developed.

7. Short term (Hourly/Sub-hourly) Demand Forecast and Aggregation at State

7.1. The distribution licensee shall develop a methodology for at least hourly, or sub-hourly, as may be decided by the Commission from time to time, demand forecastsand shall maintain a historical database.

7.2. For the purpose of ascertaining hourly load profile and for assessment of contribution of various customer categories to peak demand, load research analysis shall be conducted and influence of demand response, load shift measures, time of use shall be factored in by distribution licensee with inputs from TNSLDC. A detailed explanation for refinement conducted must be provided.

7.3. The distribution licensee shall utilize state-of-the-art tools, scientific & mathematical methodologies and comprehensive data such as but not limited to weather data, historical data, demographic and econometric data, consumption profiles, policies and drivers etc. as may be applicable to their control area.

7.4. The distribution licensee shall produce at least hourly, or sub-hourly as may be decided by the Commission from time to time, 1-year short-term (ST) and 5-year medium-term (MT) forecasts on a rolling basis and submit to TNSLDC by 30th April of each year for the ensuing year(s).

7.5. STU with inputs from TNSLDC and based on the demand estimates of the distribution licensee of the State, shall estimate, in different time horizons, namely long-term, medium term and short term, the demand for the entire State duly considering the diversity of the State.

7.6. TNSLDC shall aggregate demand forecasts by distribution licensee, consider the load diversity, congruency, seasonal variation aspects and shall submit state-level aggregate demand forecasts (MW and MWh) to the Authority and NLDC and RLDC and Commission by 31st May of each year for the ensuring year(s).

Chapter 4
Generation Resource Planning

8. Generation resource assessment and planning is the second step after demand assessment and forecasting and entails assessment of the existing and contracted resources considering their capacity credit and identification of incremental capacity requirement to meet forecasted demand including planning reserve margin.

9. Key contours and important steps in Generation Resource Planning:

9.1. Generation resource planning shall entail the following steps namely, (a) capacity crediting of generation resources, (b) assessment of planning reserve margin, and (c) ascertaining resource adequacy requirement and allocation for obligated entities within control area (state/distribution licensee).

9.2. The distribution licensee shall map all its contracted existing resources, upcoming resources, and retiring resources to develop the existing resource map in MW for the long term and medium term.

9.3. The mapping shall include critical characteristics and parameters of the generating machines, such as heat rate, auxiliary consumption, ramp-up rate, ramp-down rate, etc., for thermal machines; hydrology and machine characteristics, etc., for hydro machines; and renewable resources, their capacityutilization factors (CUFs), etc. for renewable resource–based power plants to be considered in the resource plan. All the characteristics and parameters with their values for each generating machine considered

shall be provided in the resource plan. Some of the important parameters that would be considered for this resource characteristic assessment shall include but not limited to following:

9.3.1. Name of the plant (with location, district, taluk, geo-coordinates)
9.3.2. Installed Plant Capacity (MW) (existing and planned)
9.3.3. Heat rate of thermal generating stations
9.3.4. Auxiliary consumption (MW)
9.3.5. Maximum and Minimum generation limits (MW)
9.3.6. Ramp up and Ramp down rate (MW/min)
9.3.7. Minimum up and down time
9.3.8. Plant availability factor (%)
9.3.9. Average capacity utilisation factor for past 3 years (%)
9.3.10. Historical outage rates and planned outage rates
9.3.11. Installed Capacity and generation profile of renewable energy generation resources
9.3.12. Under-construction / contracted capacity with likely date of commissioning
9.3.13. Planned Retirement of capacity or Renovation of capacity with timelines
9.3.14. Transmission expansion plans with timelines
9.3.15. Evacuation arrangements with timelines for RE generation resources

9.4. Constraints such as penalties for unmet demand, forced outages, spinning reserve requirements, and system emission limits as defined in State and Central electricity grid codes, planning criteria of CEA and emission norms specified by the Ministry of Environment and Forest shall be identified and enlisted.

9.5. The distribution licensee shall map all its existing resources, upcoming resources, and retiring resources to develop the existing resource map in MW for the Long-term and medium term power procurement planning purposes.

9.6. The distribution licensee shall also include a planning reserve as specified by the Authority or Commission, as the case may be. In the absence of any guidelines from the Commission, the distribution licensee can consider suitable planning reserve with proper justification, which will be subject to approval by the Commission. The value of planning reserve margin considered shall be stipulated in the resource plan along with justifications.

10. Capacity Crediting of Generation Resources

10.1. The distribution licensee shall compute Capacity Credit (CC) factors for their contracted generation resources by applying the net load-based approach as outlined under Regulation 10.2 of this Regulation. The five-year average of the Capacity Credit (CC) factor for each type of the contracted generation resource for the recent five years on a rolling basis shall be considered as Capacity Credit factor for the purpose of generation resource planning.

10.2. The Net Load based approach/methodology for determination of Capacity Credit (CC) factors for generation resources (including wind and solar) shall be adopted as under:

a) For each year, the hourly recorded Gross Load for 8760 hours (or time-block) shall be arranged in descending order.
b) For each hour, the Net Load is calculated by subtracting the actual wind or solar generation corresponding to that load for 8760 hours (or time-block) and then arranged in descending order similar to Step 1.
c) The difference between these two load duration curves represents the contribution of capacity factor of wind generation or solar generation, as the case may be.
d) Installed capacity of wind or solar generation capacity is summed up corresponding to the top 250 load hours.
e) Total generation from wind or solar generation corresponding to these top 250 hours is summed up.
f) Resultant CC factor is (Total Generation for top load 250 hours)/(Installed RE Capacity for top load 250 hours), as per formula below:

$$\text{CC factor} = \frac{\text{Sum of RE Generation for top } x \text{ hours}}{\text{Sum of RE Capacity for top } x \text{ hours}}$$

g) The process for CC factor determination shall be undertaken for each year for duration of past five-years and the resultant CC is the average of CC values of past 5 years.

10.3. For the purpose of inter-state contracted RE generation or intra-state RE resources, contribution of CC factor for the RE or generation resource where such resource is connectedinto grid (viz. inter-state or intra-state, as the case may be) as contracted by the distribution licensee shall be considered. For this purpose, CC factors as specified by Authority or the Commission shall be considered.

10.4. CC factors for hydro generation resources shall be computed based on water availability with different CC factors for run-of-the-river hydro power projects and dam-based/storage-based hydro power projects. CC for thermal resources shall be computed based on coal availability and forced outages.

10.5. The distribution licensee shall share CC factors for their contracted resources along with justification for its computations with TNSLDC.

10.6. TNSLDC shall calculate state-specific CC factors considering the aggregate State Demand and State Net Load and contracted RE generation resources available in the State and shall submit such CC factor information to the Authority and NLDC and RLDC from time to time.

11. Assessment of Planning Reserve Margin (PRM)

11.1. Planning Reserve Margin (PRM) as a percentage of peak load represents the excess generation resource or planning reserve required to be considered for the purpose of generation resource planning.

11.2. Such Planning Reserve Margin (PRM) factor (for example, 10%) shall be based on the reliability indices in terms of Loss of Load Probability (LOLP,

for example, 0.2%) and Normalized Energy Not Served (NENS, for example, 0.05%) as may be specified by the Authority or separately computed by the distribution licensee and STU/SLDC at state level, subject to approval of by Commission, and the same shall be considered by entities in their planning for resource adequacy requirement and generation resource capacity planning.

11.3. The capacity planning by the distribution licensee and State level resource adequacy planning by STU/TNSLDC shall factor in PRM while developing state-level Integrated Resource Plan.

12. Ascertaining Resource Adequacy Requirement and its Allocation for Control Area

12.1. Upon applying CC factors as determined under Regulation 10 of these regulations and determining adjusted capacity for contracted generation resources (existing and planned), the sum of such adjusted contracted generation capacity (existing and planned) over a time axis of at least one hour, or 15 minutes intervals may be decided by the Commission from time to time, but not more than one hour, shall form the resource map of the distribution licensee.

12.2. The distribution licensee shall subtract the resource map developed in Regulation 12.1 from the demand forecast developed in section 6 (ref. Regulation 6.13) to identify the resource gap. The resource gap in terms of RA compliance for the distribution licensee for the long term and medium term shall be developed in the manner as specified in these Regulations.

12.3. The distribution licensee shall conduct sensitivity and probability analysis to determine the most probable resource gap. The distribution licensee shall also develop long-term and medium-term resource gap plans for possible scenarios, while ensuring that at least three different scenarios (most probable, business as usual, and aggressive) are developed.

12.4. Based on most probable scenario, the distribution licensee shall undertake development of Medium-term Distribution Resource Adequacy Plan (MT-DRAP) and Short-term Distribution Resource Adequacy Plan (ST-DRAP) exercise by 31st August of each year to meet RA target requirement.

12.5. Long-term National Resource Adequacy Plan (LT-NRAP) and Short-term National Resource Adequacy Plan (ST-NRAP) reports shall act as guidance for the distribution licensee(s) for undertaking the Resource Adequacy exercises. While planning RA requirement, the distribution licensee shall duly factor in the allocation of RA requirement to the state as may be suggested by the Authority or the NLDC, as the case may be, based on contribution to National Co-incident Peak Demand (CPD) for MT-RA and ST-RA.

12.6. The Central Electricity Authority will publish the Long-term National Resource Adequacy Plan (LT-NRAP) to determine the optimal Planning Reserve Margin (PRM) requirement at the national level for ensuring reliable supply targets. The report will also include the optimal generation mix for the next 10 years thereby ensuring compliance with Resource Adequacy Requirements while meeting national demand at least cost

basis. Further, the report will feature capacity credits for different resource types on a national basis and prescribe the State contribution towards the national peak demand.

12.7. NLDC will publish a one-year look-ahead Short-term National Resource Adequacy Plan (ST-NRAP) report which will include parameters such as demand forecasts, resource availability based on under-construction status of new projects, planned maintenance schedules of existing stations, station-wise historic forced outage rates and decommissioning plans.

12.8. Based on the allocated share in national peak provided in LT-NRAP for the State, STU/TNSLDC shall allocate each distribution licensee's share in the statepeak within 15 days of the publication of LT-NRAP based on average of the percentage share in the state coincident peak demand and percentage share in the state non-coincident peak demand.

12.9. The distribution licensee based on the above allocation shall accordingly plan to contract the capacities to meet their Resource Adequacy Requirement (RAR) while ensuring that their own peak demand plus PRM is met.

12.10. The distribution licensee shall keep minimum 70% Long-term contracts, minimum 20% Medium–term contracts, and the rest to be met through Short-term contracts.

12.11. The contracts mix mentioned under Regulation 12.10 of these Regulations may be periodically reviewed by the Commission.

12.12. Provided that power procurement through Day-Ahead Market (DAM), shall not be considered towards the contribution for meeting RAR.

12.13. RA requirement planning of the state shall be done with reference to national coincident peak and of distribution licensee with reference to average of share in state coincident peak and share in state non-coincident peak, to optimize requirement of incremental capacity addition through annual rolling plan. Mid-term review of state RA requirement planning shall be conducted to check for events of slippages by states, if any.

12.14. While planning RA requirement, the distribution licensee shall duly factor in the allocation of RA requirement to the distribution licenseeas may be suggested by the STU/SLDC, as the case may be, based on average of share in state coincident peak and share in state non-coincident peakfor MT-RA and ST-RA.

12.15. The Commission shall approve MT-DRAP and ST-DRAP of the distribution licensee by 30th September of each year for the ensuring year(s) incl. annual rolling plans, as the case may be, upon taking into consideration various scenarios as well as allocation of Resource Adequacy requirement allocated to the State/distribution licensee based on its contribution to the National/state peak respectively as determined by Authority/NLDC/RLDC and STU/SLDC, as the case may be.

Chapter 5
Power Procurement Planning

13. Procurement planning shall consist of (a) determining the optimal power procurement resource mix, (b) deciding on the modalities of procurement type and tenure, and (c) engaging in the capacity trading or sharing to minimize risk of resource shortfall and to maximize rewards of avoiding stranded capacity or contracted generation.

14. Procurement Resource Mix

14.1. The distribution license in its power procurement strategy shall identify an optimal procurement generation resource mix that shall enable smooth RE integration in its portfolio of power procurement resource options while meeting reliability standards.

14.2. For identification of the optimal generation procurement resource mix, optimization techniques and least-cost modelling shall be employed in order to avoid stranding of assets. The distribution licensee shall engage in adoption of least cost modelling and optimization techniques and demonstrate the same in its overall power procurement planning exercise to be submitted to Commission for approval.

14.3. Procurement by distribution licensee shall be consistent with the identified resource mix and considering overall national electricity plan and policies notified by the Appropriate Government from time to time.

14.4. The power capacity procurement from renewable energy sources for fulfilling the RPO targets shall be carried out as per Tamil Nadu Electricity Regulatory Commission (Renewable Energy Purchase Obligation) Regulations, 2023 and amendments thereof.

14.5. The power procurement from Wind, Solar PV, Wind Solar Hybrid, Round the Clock (RTC) generations shall be carried out as per the guidelines for tariff based competitive bidding process notified by the Ministry of Power.

14.6. The distribution licensee shall contract storage capacity corresponding to the results of MT- DRAP capacity addition requirement for future years from Battery Energy Storage System (BESS) and Pump Storage Projects (PSP) as per the guidelines for tariff based competitive bidding process notified by the Ministry of Power.

14.7. The distribution licensee may contract power through Central Agencies / Intermediaries / Traders / Aggregators / Power Exchanges or through agreements / Banking arrangements with other distribution licensee in compliance with competitive bidding guidelines.

14.8. The distribution licensee may procure power on Short-term and Medium-term basis through DEEP and PUShP portal.

15. Procurement Type and Tenure

15.1. The distribution licensee, while determining the modalities and tenure of procurement of resource mix, shall ensure that at the initial level, available capacity within the states hall be optimized. For further optimization, procurement contract shall be decided first within the state subject to the least cost resource availability considering transmission

constraints & cost of transmission for procurement from outside the state and then across states if necessary.

15.2. The distribution licensee shall identify the generation resource mix and also procurement strategy in medium-term and short-term horizon and seek approval of the Commission.

15.3. The distribution licensee shall demonstrate to the Commission 100% tie-up for the first year and a minimum 90% tie-up for the second year to meet the requirement of their contribution towards meeting state peak. Only resources with long / medium / short-term contracts shall be considered to contribute to the RAR.

15.4. For subsequent three years, the distribution licensee shall also furnish a plan to meet estimated requirement of their contribution to meet state peak for the Commission's approval.

15.5. The MT-DRAP shall be carried out by the distribution licensee on an annual rolling basis considering the contracted capacity as a part of the system and shall optimize for additional capacity required.

15.6. The distribution licensee through MT-DRAP, shall demonstrate to the Commission their plan to meet their Peak demand and energy requirement with a mix of Long-term, Medium-term, and Short-term contracts.

Provided that the distribution licensee shall keep the share of contracts in the range as mentioned under Regulation 12.10 of these Regulations.

15.7. Assessment through Annual Rolling Plan shall ascertain incremental capacity addition requirement through MT/ST upon factoring in existing and planned procurement initiatives of the distribution licensee.

15.8. The distribution licensee shall contract capacities by 30th November of each year and submit the Annual Rolling Plan to STU/TNSLDC by 31st December of each year for ensuring year(s).

15.9. STU and TNSLDC shall submit state-level aggregated plan to RLDC and RLDC shall submit state-level aggregated plan to NLDC by 31st January of each year for the ensuing year(s).

16. Sharing of Capacity

16.1. The distribution licensee shall duly factor in the possibility of short-term capacity sharing while preparing the Resource Adequacy plan and optimally utilize the capacity available within the state through competitive sharing arrangements or other mechanisms, and then use the platform for inter-state capacity sharing or trading mechanism if created by the Central Commission or other mechanisms as the case may be, and optimize the capacity costs as far as possible.

16.2. The distribution licensee shall submit information about contracted capacity to the TNSLDC and the STU for compliance verification.

16.3. The distribution licensee, the STU and the TNSLDC shall seek approval of the Commission to the procurement plan as well as Annual Rolling Plans.

17. Approval of Power Purchase Agreement

17.1. Any new Capacity arrangement/tie-up shall be subject to the prior approval of the Commission in view of necessity, reasonableness of cost of power purchase and promotion of working in an efficient, economical and equitable manner.

17.2. All procurement of Long/Medium/Short-term power from various sources shall be carried out as per the Guidelines/Rules/Regulations/Policies issued by the Central Government/Appropriate Commission from time to time.

17.3. Any new power purchase agreement for Long/Medium-term or amendments to existing Long/Medium-term Power Purchase Agreement (PPA's)/ Power Sale Agreement (PSA) entered into by the distribution licensee shall be subject to the prior approval of the Commission.

17.4. The distribution licensee shall submit the list of all existing Power Purchase Agreements executed with different conventional power plants as well as RE Generators along with the Resource Adequacy plan.

18. Variation in Power Purchase

18.1. The distribution licensee may undertake additional power procurement during the year, over and above the approved resource adequacy procurement plan on account of following exemptions:

18.2. In case, where there has been an unanticipated increase in the demand for electricity or a shortfall or failure in the supply of electricity from any approved source of supply during the year or when the sourcing of power from existing tied-up sources becomes costlier than other available alternative sources, the distribution licensee may enter into additional agreement for procurement of power.

18.3. The distribution licensee may enter into a Short-term arrangement or agreement for procurement of power when faced with emergency conditions that threaten the stability of the grid, or when directed to do so by the SLDC/RLDC to prevent grid failure or during exigency conditions and for banking with other States on Short-term basis without prior approval of the Commission.

Provided that the details of such Short-term procurement shall be submitted to the Commission within 45 days from date of procurement of power.

Chapter 6
Monitoring and Compliance

19. Monitoring and Compliance

19.1. **Monitoring and Reporting**: Based on the MT-DRAP and ST-DRAP, STU and TNSLDC shall communicate the state-aggregated capacity shortfall to the Commission by 15th September of each year for the ensuring year(s) and advise the distribution licensee to commit additional capacities. The Commission shall approve RA plans by 30th September of each year.

19.2. **Treatment for shortfall in RA Compliance**: Distribution licensee shall comply with the RA requirement and in case of non-compliance, appropriate non-compliance charge shall be applicable for the shortfall for RA compliance.

19.3. For shortfall in RA compliance, TNSLDC shall levy and collect non-compliance charge from the concerned Distribution Licensee.

19.4. The rate of Non-compliance charges shall be equivalent to 1.1 times the Marginal Capacity Charge (Rs/kW/month) or 1.25 times the Average Capacity Charge (Rs/kW/month) whichever is higher, as approved by the Commission for the power procurement by concerned distribution licensee

under its ARR/Tariff Order for the relevant financial year, unless separately specified by the Commission.

19.5. The distribution licensee shall not be allowed to recover such non-compliance charge as part of its ARR.

Chapter 7
Roles and Responsibilities and Timelines

20. Data Requirement and Sharing Protocol

20.1. Distribution licensee shall maintain and share with STU/TNSLDC all data related to demand assessment and forecasting such as but not limited to consumer data, historical demand data, weather data, demographic and econometric variables, T&D losses, actual electrical energy requirement and availability including curtailment, peak electricity demand, and peak met along with changes in demand profile (e.g.: agricultural shift, time of use, etc.), historical hourly load shape, etc.

20.2. Distribution licensee shall maintain all statistics and database pertaining to policies and drivers, such as LED penetration, efficient fan penetration, appliance penetration, demand side management and energy efficiency measures, increased usage of electrical appliances for cooking, etc., in households, increase in commercial activities for geographic areas/regions, increase in number of agricultural pumps and solarization within control area, changes in specific energy consumption, consumption pattern from seasonal consumers such as tea plants, DSM and DERs, EVs and OA, National Hydrogen Mission, reduction of AT&C losses, etc. shall also be shared.

20.3. Distribution licensee shall maintain at least past 10 years of statistics in its database pertaining to consumption profiles for each class of consumers, such as domestic, commercial, public lighting, public water works, irrigation, LT industries, HT industries, railway traction, bulk (non-industrial HT consumers), open access, captive power plants, insights from load survey, contribution of consumer category to peak demand, seasonal variation aspects, etc. shall also be shared.

20.4. TNSLDC shall maintain the licensee-specific as well as aggregate for state as whole, the statistics and database pertaining to aggregate demand assessment and forecasting data mentioned above and share state-level assessment with the Authority and the NLDC for national assessment from time to time.

20.5. The distribution licensee shall share information and data pertaining to the existing and contracted capacities with their technical and financial characteristics including hourly generation profiles to with STUand TNSLDC for computation of state-level capacity credit factors and for preparation of state-level assessment.

20.6. TNSLDC and STU shall aggregate generation data and share state-level assessment with the Authority and NLDC for assessment of RA requirement.

20.7. STU shall communicate allocation of national RA requirement to the distribution licensee.

21. Timelines

21.1. Distribution licensee shall submit demand forecasts to TNSLDC by 30th April of each year for the ensuring year(s).

21.2. TNSLDC shall aggregate and submit state-level forecasts to the Authority and the NLDC by 31st May of each year for the ensuring year(s).

21.3. Distribution licensee shall perform MT-DRAP and ST-DRAP exercise by 31st August of each year for the ensuring year(s).

21.4. STU and TNSLDC shall communicate the state-aggregated capacity shortfall to the Commission by 15th September of each year.

21.5. The Commission shall approve RA plans by 30th September of each year.

21.6. STU and TNSLDC shall submit state-level aggregated plan to NLDC by January of each year.

22. Publication of the information on website

22.1. The monthly/weekly/day-ahead/intraday power procurements/sale by the distribution licensee and generator schedule shall be made available on the websites of the distribution licensee and TNSLDC within 45 days of such procurements/sale with ease of access to the current as well as archived data.

22.2. TNSLDC shall also publish the monthly Merit Order Dispatch (MoD) stack along with per unit variable cost of each generating station on its website.

23. Constitution of dedicated cells by Distribution Licensee

23.1. The Distribution Licensee shall establish a planning cell for Resource Adequacy within three months of the Regulation coming into force. The cell shall have the requisite capability and tools for demand forecast, capacity, RE integration etc.

23.2. Another round the clock dedicated cell shall also be constituted by Distribution Licensee for power purchase/sell in real-time, and also undertake intra-day, day-ahead, week ahead power procurement through Power Exchanges or any other means. Distribution Licensee shall frame suitable guidelines for the modus operandi of the dedicated cells in line with the spirit of this Regulation and shall apprise the Commission for the same within 45 days from the date of coming into force of this Regulations.

23.3. The distribution licensee shall make the Resource Adequacy Plan in consultation with State Sector Generating Companies, other Distribution Licensee, Central Sector Generating Companies, Transmission Companies, National / Regional /State Load Dispatch Centres, and Central Electricity Authority. It may also make enquiries with the Trading Companies and States with surplus power to estimate the likely availability and price of power across the country for peak, off-peak and normal periods.

Chapter 8
Miscellaneous

24. Power to Give Directions

24.1. The Commission may from time to time issue such directions and orders as considered appropriate for implementation of these regulations.

25. Deviation from the Norms

25.1. The parametric norms considered for approval of the Resource Adequacy Plan and Power procurement plan thereof, may be determined in deviation from the norms specified in these Regulations:
Provided that the reasons for deviation from the norms specified under these Regulations shall be recorded in writing.

26. Power to Relax

26.1. The Commission may by general or special order, for reasons to be recorded in writing, and after giving an opportunity of hearing to the parties likely to be affected, may relax any of the provisions of these Regulations on its own motion or on an application made before it by an interested person.

27. Issue of Orders and Practice directions

27.1. Subject to the provisions of the Act, the Commission may from time to time issue Orders and Practice Directions with regard to the implementation of these Regulations.

28. Powers to Amend

28.1. The Commission may, at any time, vary, alter, modify or amend any provisions of these Regulations.

29. Power to Remove Difficulties

29.1. If any difficulty arises in giving effect to the provisions of these Regulations, the Commission may, by an order, make such provisions, not inconsistent to the provision of the Act and these Regulations, as may appear to be necessary for removing the difficulty.

(By order of the Commission)
Sd/- dated 13-06-2024
(Secretary)
Tamil Nadu Electricity Regulatory Commission

Annexure-I: Data Requirement Templates

Data template for demand forecasts for state and its distribution licensee as following:

Demand Forecast (Summary Statement for State and DISCOM separately)-Discom wise(Name of Discom:)									
Sr. No.	**Particulars**	**Actual of Previous Years**			**Current Year**	**YoY growth rate/CAGR-as applicable (%)**	**Projections**		
		Yr -1	**Yr-2**	**Yr-n**			**Yr-1**	**Yr-2**	**…Yr-10**
1	**Energy Sale-MUs*(Consumer Category wise as per Retail Supply Tariff Order)***								
	Residential								
	Commercial								
	HT-Industries								
	HT-I Industries, Factories, Information Technology Services								
	HT-IIA Government Educational Institutions/Hospitals, Railway Traction, CMRL, Lift Irrigation societies, etc.								
	HT-IIB Private Educational Institutions & its hostels, segregated Medical colleges								
	HT-III Miscellaneous categories								
	HT-IV Construction activities and other temporary purposes								
	HT-V Public EV Charging Stations								
	LT-Industries								

Demand Forecast (Summary Statement for State and DISCOM separately)-Discom wise(Name of Discom:)									
Sr. No.	**Particulars**	**Actual of Previous Years**			**Current Year**	**YoY growth rate/CAGR-as applicable (%)**	**Projections**		
	LT-IA Domestic, Multi-tenements, Old age homes, Handlooms								
	LT-IB Huts								
	LT-IC Bulk supply with single point metering								
	LT-ID Common facilities in Multi-tenements								
	LT-IIA Public Lighting, Water supply provided by Govt./Local bodies								
	LT-IIB (1)Government Educational Institutions its Hostel, Govt. Hospital, Other hospitals rendering totally free service								
	LT-IIB (2)Private Educational Institutions/Hostel, Segregated Private Medical college								
	LT-IIC Actual places of Public worship								
	LT-IIIA (1)Cottage & Micro Industries								
	LT-IIIA (2)Power Looms								
	LT-IIIB Industries, Information Technology services								
	LT-IV Agriculture and allied activities								
	LT-V Miscellaneous/General purpose								
	LT-VI Construction activities and Temporary purposes								

Demand Forecast (Summary Statement for State and DISCOM separately)-Discom wise(Name of Discom:)									
Sr. No.	**Particulars**	**Actual of Previous Years**			**Current Year**	**YoY growth rate/CAGR-as applicable (%)**	**Projections**		
2	**Total Energy Sale(MU)-(Cumulative of all consumer categories excluding Open Access Sales)**								
3	**Total Energy Sale(MU)-(Cumulative of all consumer categories including Open Access Sales)**								
4	**YoY growth rate for total energy Sales(%) (excluding OA)**								
5	**YoY growth rate for total energy Sales(%) (including OA)**								
6	Distribution losses-in%								
7	Distribution losses-in MU								
8	**Supply/Requirement at DISCOM Boundary(MU)**								
9	Intra-State Transmission losses-in%								
10	Intra-State Transmission losses-in MU								
11	**Supply/Requirement at State Boundary(MU)**								
12									

Demand Forecast (Summary Statement for State and DISCOM separately)-Discom wise(Name of Discom:)									
Sr. No.	**Particulars**	**Actual of Previous Years**			**Current Year**	**YoY growth rate/CAGR-as applicable (%)**	**Projections**		
	Inter-State Transmission losses-in%								
13	Inter-State Transmission losses-in MU								
14	**Ex-Bus Requirement of DISCOM(MU)(excluding OACs, Railways)-RESTRICTED**								
15	Energy Wheeled for Railways/OA Consumers (as applicable)								
16	**Ex-Bus Requirement of DISCOM(MU)(including OA, Railways)-RESTRICTED**								
17	Unsupplied energy due to system constraints (MU)								
18	**Ex-Bus Requirement of DISCOM(MU)(excluding OA, Railways)-Unrestricted**								
19	**Ex-Bus Requirement of DISCOM (MU)(including OA, Railways)-Unrestricted**								
20	**System Load Factor**								

Demand Forecast (Summary Statement for State and DISCOM separately)-Discom wise(Name of Discom:)									
Sr. No.	**Particulars**	**Actual of Previous Years**			**Current Year**	**YoY growth rate/CAGR-as applicable (%)**	**Projections**		
21	**Peak load of DISCOM(MW)(excluding OA, Railways)**								
22	**Peak load of DISCOM(MW)(including OA, Railways)**								

Data template for historical load, RE installed capacity, and RE generation data in hourly resolution as following:

Year	Month	Day	Hour	Load (MW)	Solar IC (MW)	Solar Gen (MW)	Wind IC (MW)	Wind Gen (MW)	Hydro IC (MW)	Hydro Gen (MW)
2018	4	1	1							
..	..	..	..							
2024	3	31	24							

Data template for technical and financial characteristics of each generating station as following:

Sr. No.	Generating Stations	Resource Type	Installed Capacity (MW)	Allocated Capacity (MW)	Commissioning Year	Expected Retirement Year	Fixed Cost (Rs/kW/yr.)	Variable Cost (Rs/kWh)	Heat Rate (at full load)	Ramp Rate (MW/min)	Start Up Cost (Rs.)	Start Up time (h)	Planned maintenance	Forced Outage	PLF (%)	Date of signing of PPA	Date of expiry of PPA
I	**CENTRAL GENERATING STATIONS**																
1																	
II	**STATE GENERATING STATIONS**																
1																	
II	**HYDRO**																
1																	
III	**RENEWABLE**																
1																	
IV	**IPP**																
1																	

Data template for peak demand and energy requirement projections of all Distribution Licensees and SEZs as following:

Source	**TANGEDCO**	
Unit	**MUs**	**Peak MWs**

Source	TANGEDCO	
2018-19		
2019-20		
2020-21		
2021-22		
2022-23		
2023-24		
2024-25		
2025-26		
2026-27		
2027-28		
2028-29		
2029-30		
2030-31		
2031-32		
2032-33		
2033-34		
…		
Year-n+10		

(By order of the Commission)

Sd/- dated 13-06-2024

(Secretary)

Tamil Nadu Electricity Regulatory Commission