MAHARASHTRA ELECTRICITY REGULATORY COMMISSION

EXPLANATORY MEMORANDUM (EM)

On

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

March 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
LOLP	:	Loss of Load Probability
LT	:	Long-Term
LT-DRAP	:	Long-Term Distribution Resource Adequacy Plan
MERC	:	Maharashtra Electricity Regulatory Commission
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
ToR	:	Terms of Reference
WG	:	Working Group

Introduction

Maharashtra is the largest producer and consumer of electricity in India. Its peak demand and energy requirement are both projected to grow over the next few years. On the supply side, share of renewable energy (RE) in its installed capacity has grown from 21% in FY19 to 30% in FY23, and accounting for the 5th highest RE installed capacity in India. Maharashtra's Unconventional Energy Generation Policy aims at implementing 17 GWs of RE projects by FY25, including 13 GWs of solar. This will further entail a rapid expansion from the current 4.9 GWs of solar and 5.1 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 licensees (DLs) 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 licensees (DLs) 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

Accordingly, the Maharashtra Electricity Regulatory Commission (MERC or Commission) formed a Working Group (WG) to conduct a study of RA framework and assist in preparation of Draft

Regulations for deployment of RA framework in the State. the Terms of Reference (ToR) of the WG was as follows:

1. Study of Model FoR Regulations for Resource Adequacy Framework.
2. Review of Indian Electricity Grid Code/SGC for adopting the key provisions related to Resource Adequacy Framework.
3. Discuss the relevant aspects with the stakeholders.
4. Identify implementation issues and need of detailed procedures if any, after due discussion with the concerned stakeholders and suggesting solution/way forward to address such issues.
5. Any other issues arisen during discussion.

The WG held its first meeting on 08 December 2023, during which timelines for development of Draft RA Regulations, key aspects of RA, illustrative computations, and data requirement were discussed. Subsequently, the WG held discussions with relevant stakeholders, coordinated for data collection, an undertook illustrative computations for the purposes of demonstration of key aspects of RA. These computations and key contours of Draft RA Regulations were discussed during the WG's 2nd meeting, held on 18 January 2024.

Based on illustrative computations and key contours developed by the WG, MERC has notified the Draft Maharashtra Electricity Regulatory Commission (Framework for Resource Adequacy) Regulations, 2024 on 07 January 2024.

The Draft MERC (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 Clause 6 of the Draft RA Regulations, DLs should adopt the following methodology for demand assessment and forecasting under RA:

Figure 1: Demand Assessment and Forecasting Methodology

DLs 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. DLs 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 MERC (Demand Side Management Implementation Framework) Regulations, 2010 and amendments thereof.

Based on the collection of comprehensive inputs, DLs 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 DLs 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 be a 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 Clause 10 of the Draft RA Regulations, DLs and 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.
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.

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

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:

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

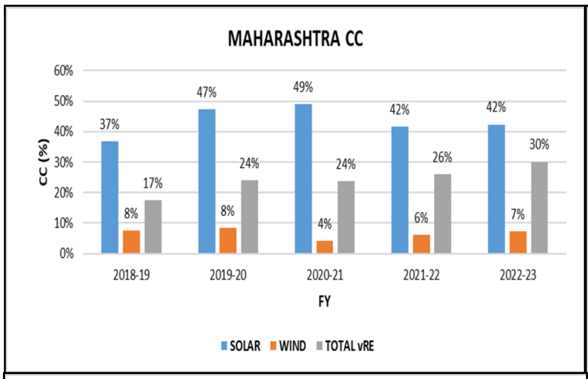
[2] Drivers of the Resource Adequacy Contribution of Solar and Storage for Florida Municipal Utilities, LBNL, 2019 10 24.

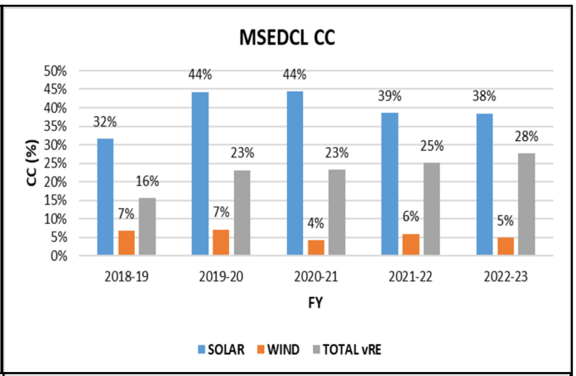
1. Annual peak (MW) and energy (MWh) projections of the next five years.
2. Hourly load profile (MWh) of the recent 5 years.
3. Hourly generation profile of solar, wind, and hydro resources of the recent five years.
4. At least hourly, or else monthly, installed capacities of solar, wind, and hydro resources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

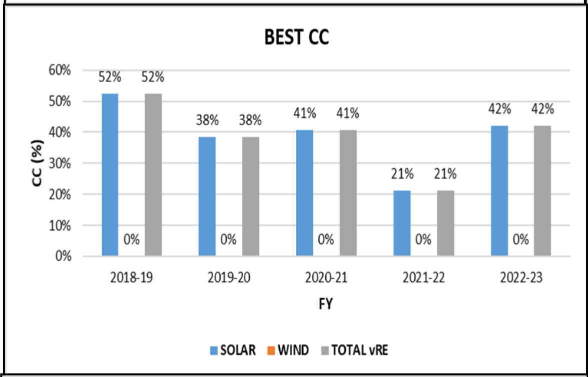
The CC factors should be such that contributions of inter-state and intra-state RE generators contracted by the distribution licensees are considered. There need not be a separate methodology for imports or existing/new resources. CC for hydro resources should be computed based on water availability. 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.

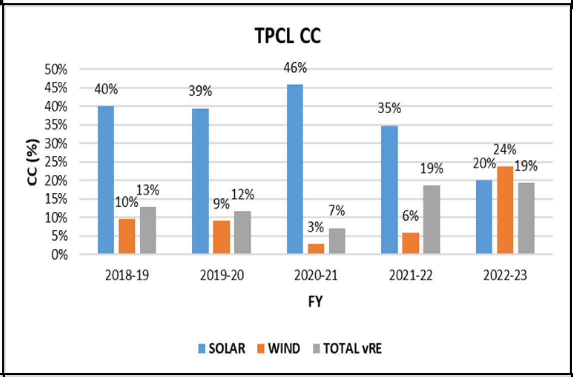
DLs and SLDC should compute CC factors for their control areas and use them in their assessment of supply availability.

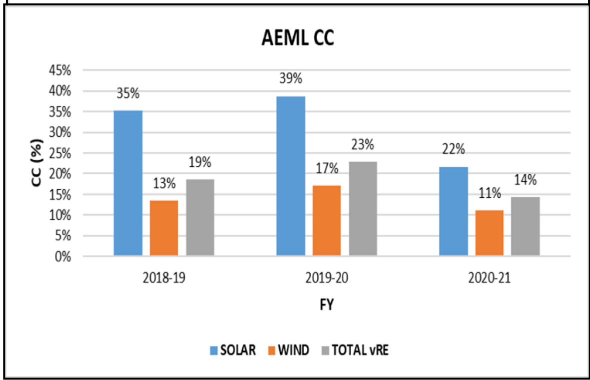
Illustrative and preliminary numbers adopting the above methodology are as follows:











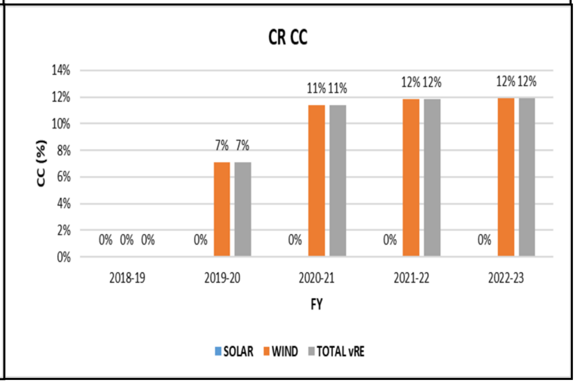


Figure 2: Illustrative CC Factors

Maharashtra:

- Solar CC is higher than wind CC.
- CC factor for wind varies from 4-9% while for solar it varies from 37-49%
- CC factor for wind and solar presents varying trend over 5-year period.
- Composite CC factor for VRE is in the range of 17-32%.

MSEDCL:

- Solar CC is higher than wind CC.
- CC factor for wind varies from 4-7% while for solar it varies from 32-44%
- CC factor for wind and solar presents varying trend over 5-year period.
- Composite CC factor for VRE is in the range of 15-28%.

BEST:

- Solar CC is calculated while wind CC is zero
- CC factor for solar varies from 21-52%
- CC factor for solar presents varying trend over 5-year period.

TPCL:

- Solar CC is higher than wind CC.
- CC factor for wind varies from 3-24% while for solar it varies from 20-46%
- CC factor for wind and solar presents varying trend over 5-year period.
- Composite CC factor for VRE is in the range of 7-19%.

AEML:

- Average of CC of the first 3 years is considered for illustrative purposes; this assumption has been made since for subsequent two years, data on hybrid capacity and generation is available as against independent.
- Solar CC is higher than wind CC except for FY23
- CC factor for wind varies from 7-56% while for solar it varies from 18-39%
- CC factor for wind and solar presents varying trend over 5-year period.
- Composite CC factor for VRE is in the range of 14-44%.

CR:

- CC factor for wind varies from 7-12%
- CC factor for wind presents varying trend over 5-year period.
- Composite CC factor for VRE is in the range of 7-12%.

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 Clause 11 of the Draft RA Regulations, DLs 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 each DL and state as a whole 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 DLs. There are two methods for allocating state RA requirement down to DLs, one based on percentage share of DL 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 Clause 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 Maharashtra:

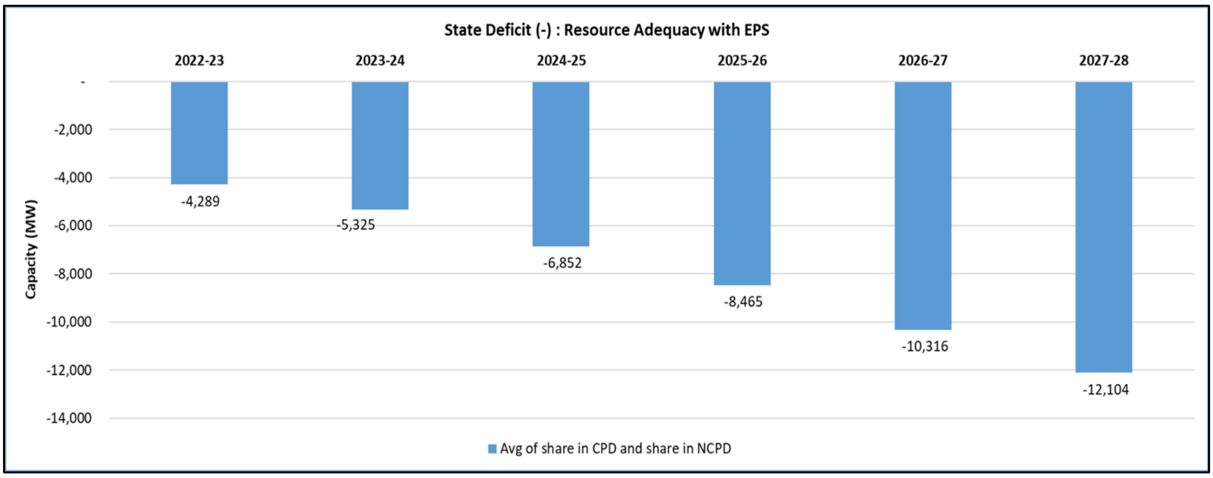


Figure 3: Preliminary Identification of RA Requirement

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 12.1 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 4,289 MW in FY23, the same is allocated to DLs based on their respective shares in the state peak with PRM. This allocation can be seen below:

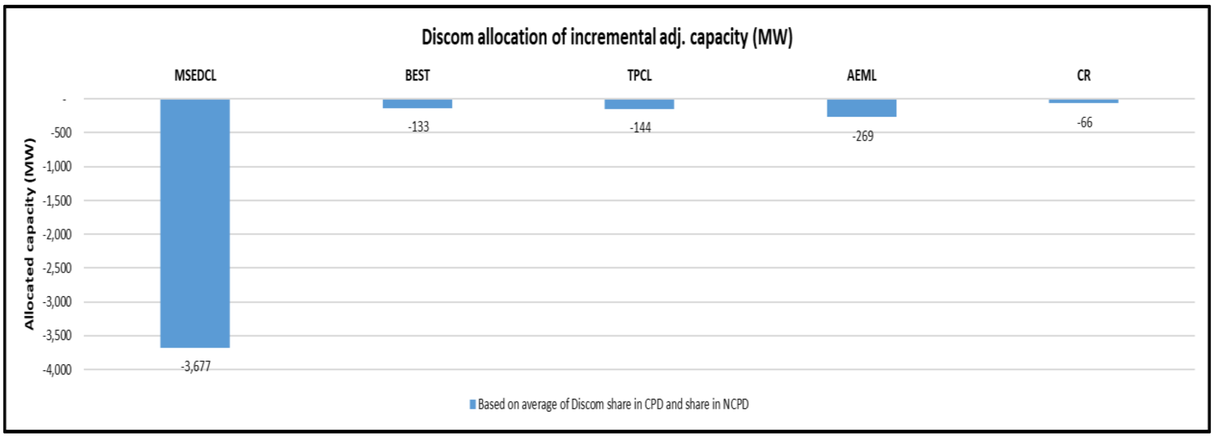


Figure 4: Allocation of RA Requirement to DLs for FY23

As, MSEDCL has the highest share in the state peak demand, highest allocation has been done.

Similarly, the following chart shows the allocation of state capacity requirement of 12,104 MW in FY28:

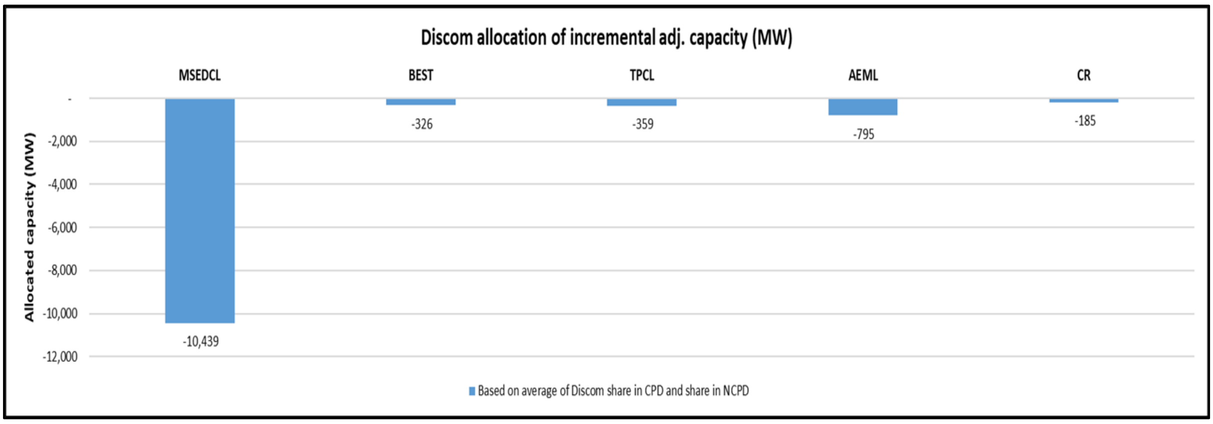


Figure 5: Allocation of RA Requirement to DLs for FY28

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

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
    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.

[3] National Electricity Plan, 2023, CEA

With reference to Clause 14 of the Draft RA Regulations, the distribution licensees 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. DLs 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 Clause 15 of the Draft RA Regulations, DLs 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 Clause 16 of the Draft RA Regulations, DLs 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 Clause 19 of the Draft RA Regulations, the following timelines should be followed:

1. DLs 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, DLs 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 MSLDC 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. DLs should contract capacities by 30th November of the applicable year.
7. DLs 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 DLs 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:

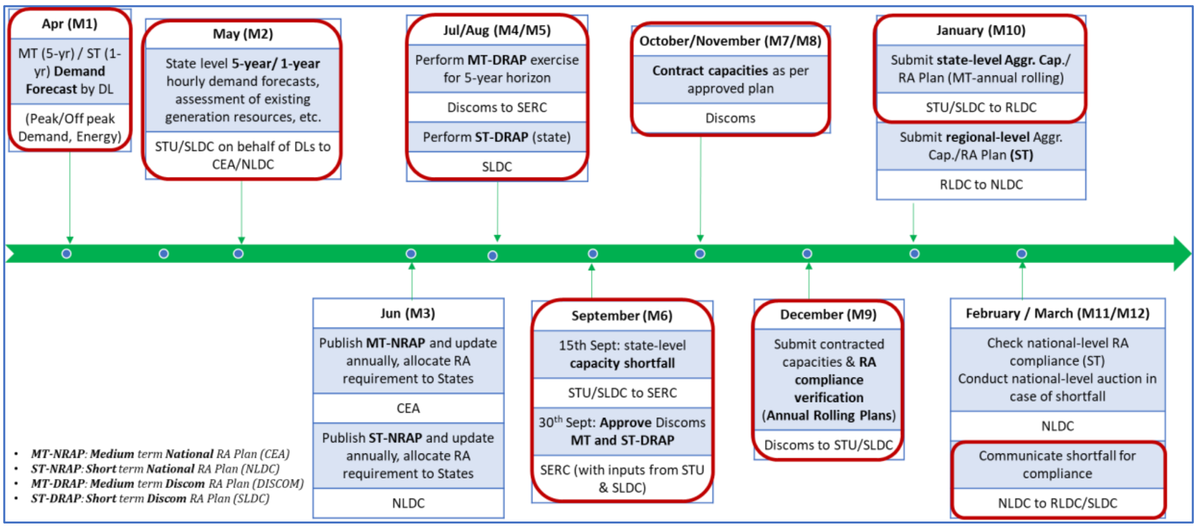


Figure 6: Process Flowchart for RA Planning