Uttar Pradesh Electricity Regulatory Commission

Vidyut Niyamak Bhawan, Vibhuti Khand, Gomti Nagar, Lucknow-226010

No. UPERC/Secy/D (Tariff)/24-742 Dated: 16 Aug, 2024

PUBLIC NOTICE

In the matter of:

Inviting Comments on Draft Uttar Pradesh Electricity Regulatory Commission (Framework for Resource Adequacy) Regulations, 2024

The Commission has framed draft Regulations in the matter of Framework for Resource Adequacy. The draft Regulation and Explanatory Memorandum is put up on the website of the Commission: www.uperc.org for comments of all stakeholders and the public at large. The deadline for submission of comments (in hard and soft copies) is now further extended till 17:00 hours on Sep 11, 2024. A Public Hearing on the matter shall be held on Sep 11, 2024 at 11:30 hours in the office of the Commission.

Secretary

Ph: 0522-2720426, 2720427
Fax: 2720423
E-mail: secretary@uperc.org

UTTAR PRADESH ELECTRICITY REGULATORY COMMISSION

Regulations for Resource Adequacy Framework

(Draft)

No………. Date……….

NOTIFICATION

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 on this behalf, and after previous publication, the Uttar Pradesh Electricity Regulatory Commission hereby makes the following Regulations, namely -

Chapter 1 Preliminary

1. Short Title, Extent, and Commencement

1.1. These Regulations may be called the Uttar Pradesh Electricity Regulatory Commission (Framework for Resource Adequacy) Regulations, 2024.

1.2. These Regulations shall extend to the whole state of Uttar Pradesh.

1.3. These Regulations shall come into force from the date of their notification in the Official 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 licensees, State Load Despatch Centre, State Transmission Utility, and other grid-connected entities and stakeholders within Uttar Pradesh.

4. Definitions

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

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

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

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

4.1.4. "**Commission**" or "**State Commission**" means the Uttar Pradesh Electricity Regulatory Commission (UPERC) constituted under the Act.

4.1.5. "**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.

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

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

4.1.8. "**Medium-Term Distribution Resource Adequacy Plan**" or

"**MT-DRAP**" means plan for assessment of medium-term resource adequacy by the distribution licensee.

4.1.9."**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.

4.1.10. "**Normalized Energy Not Served**" or "**NENS**" is normalization of the EENS by dividing it by the total system load.

4.1.11. "**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.

4.1.12. "**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.

4.1.13. "**Short term**" means one year for development of demand forecast, generation resource plan, and procurement plan.

4.1.14. "**Short-Term Distribution Resource Adequacy Plan**" or "**ST-DRAP**" means plan for assessment of short-term resource adequacy by the distribution licensee.

4.2. The Words or expressions occurring in these Regulations and not defined herein, but defined in the Act or any other Regulations of the Commission, shall bear the same meaning as in the Electricity Act, 2003 or any other Regulations of the Commission, as amended from time to time. Expressions used herein but not specifically defined in these Regulations or in the Electricity Act, 2003 but defined under any law passed by a competent legislature and applicable to the electricity industry in the state shall have the meaning assigned to them in such law. Expressions used herein but not specifically defined in these Regulations or in the Acts or any law passed by a competent legislature shall have the meaning as is generally assigned in the electricity industry.

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 the following important steps:

a) Demand assessment and forecasting

b) Generation resource planning

c) Procurement planning

d) 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 of up to five years; and

b) Short-term procurement plan for a period of 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.

Chapter 3

Demand Assessment and Forecasting

6. Forecasting methodology

6.1. Distribution licensees shall develop and prepare demand assessment and forecasting considering the guidelines for demand forecast issued by the Authority from time to time.

6.2. Demand assessment and forecasting shall entail hourly or sub-hourly assessment and forecasting of demand within the distribution area of the distribution licensee for multiple horizons (short/medium/long-term) using comprehensive input data, policies and drivers and scientific mathematical modelling tools.

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

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

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

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 as mentioned in Regulation-6.5, after recording the merits of the method. Further, distribution licensee should use the 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 of these Regulations.

6.7. For the purposes of selecting methodology to be used for energy forecasting for a consumer category, the distribution licensee shall conduct statistical analysis and select the method for which the 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 may modify the energy forecast obtained, for each consumer category, by considering the impact of 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) demand-side management

b) open access

c) distributed energy resources

d) DSM and demand response measures

e) electric vehicles

f) tariff signals

g) changes in specific energy consumption

h) increase in commercial activities with electrification

i) increase in the number of agricultural pump sets and their solarization

j) changes in consumption pattern from seasonal consumers

k) availability of supply

l) policy influences such as 24X7 supply to all consumers, LED penetration, efficient use of fans/appliances, increased use of appliances for cooling/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 consumer category.

6.10. The distribution licensee may take into consideration any other factor not mentioned in Regulation 6.9 after recording the merits of its consideration.

6.11. The summation of the energy forecast (MWh) for various consumer categories upon adjusting for captive, prosumer, and open access consumers, as obtained as per Regulations 6.5 to Regulation 6.11, as the case may be, shall be the energy forecast for the licensee at consumer category level.

6.12. The distribution licensee shall calculate the energy forecasts (in MWh) by adding distribution losses as per the loss trajectory proposed by the Distribution Licensee, Intra-State Transmission Losses and Inter-State Transmission Losses.

Provided that for the purpose of True-up, APR and ARR, Normative Loss trajectory as specified by the Commission from time to time shall be considered.

6.13. 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 energy forecasts (in MWh) obtained in Regulation 6.13. If any other appropriate load factor is considered for future years, a detailed explanation shall be provided.

6.14. 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.

6.15. The distribution licensee shall maintain a historical database of demand forecasting.

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

6.17. 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. Aggregation of Demand Forecast at State Level

7.1. The distribution licensee shall produce hourly or sub-hourly 1-year short-term (ST) and 5-year medium-term (MT) forecasts on a rolling basis and submit them to SLDC by 30th April of each year for the ensuing year(s).

7.2. SLDC shall aggregate demand forecasts by distribution licensees, considering the load diversity, congruency, seasonal variation aspects and shall submit state-level aggregate Long-Term and Medium-Term demand forecasts (MW and MWh) to the Authority and Short-Term demand forecasts to NLDC and NRLDC by 31st May of each year for the ensuing year(s).

Chapter 4
Generation Resource Planning

8. Distribution licensee shall plan and asses the required generation resources considering their existing and contracted resources, 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 to distribution licensees

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, technical minimum load etc., for thermal machines; hydrology and machine characteristics, etc., for hydro machines; reactor and other characteristics of nuclear resources, and Capacity 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.

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

9.5. 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, the distribution licensee can consider a suitable planning reserve. The value of the planning reserve considered shall be stipulated in the resource plan along with justifications.

10. Capacity Crediting of Generation Resources

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 10.1 of this Regulation. The 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.

10.1. The Net Load based approach/methodology for the determination of Capacity Credit (CC) factors for variable renewable 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 taken.

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.

c) Installed capacity of wind or solar generation capacity is summed up corresponding to the top 250 load hours.

d) Total generation from wind or solar generation corresponding to these top 250 hours is summed up.

e) Resultant CC factor is (Total Generation for top load 250 hours)/(Installed RE Capacity for top load 250 hours), as per the formula below:

$$CC\ Factor = \frac{Sum\ of\ RE\ Generation\ for\ top\ 250\ hours}{Sum\ of\ RE\ Capacity\ for\ top\ 250\ hours}$$

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

10.2. Distribution Licensees may use Expected Load Carrying Capability (ELCC) approach, as outlined in GoI Guidelines, to estimate CC Factors for variable renewable generation resources after recording merits of the same.

10.3. Wherever available and suitable, distribution licensees shall use CC Factor specified by the Authority.

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

10.5. CC for thermal resources shall be computed based on coal availability and forced outages.

10.6. The distribution licensee shall share CC factors for their contracted resources along with justification for its computations with State Load Despatch Centers.

10.7. SLDC 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, NLDC and RLDC from time to time.

11. Assessment of Planning Reserve Margin (PRM)

11.1. Planning Reserve Margin (PRM) factor shall be based on the reliability indices in terms of LOLP and NENS as may be specified by the Authority or separately computed by the distribution licensee and SLDC at the state level, subject to the approval of the Commission, and the same shall be considered by distribution licensees in their planning for resource adequacy requirement and generation resource capacity planning.

11.2. The capacity planning by the distribution licensee and State level resource adequacy planning by SLDC 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 15-minute blocks or longer as 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 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, medium-term and short-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 the most probable scenario, the distribution licensee shall undertake the 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. RA requirement planning shall be done with reference to national coincident peak to optimize the requirement of incremental capacity addition through an annual rolling plan. Long-Term National Resource Adequacy Plan (LT-NRAP) published by the Authority and Short-Term National Resource Adequacy Plan (ST-NRAP) published by NLDC shall act as guidance for distribution licensees for undertaking the Resource Adequacy exercise.

12.6. Based on the allocated share in the national peak provided in LT-NRAP for the State, SLDC shall allocate each distribution licensee's share in the national peak within 15 days of the publication of LT-NRAP.

12.7. Based on the share in national peak provided in LT-NRAP, each distribution licensee shall plan to contract the capacities (peak contribution * (1 + National level PRM)) prescribed by LT-NRAP or higher to be procured to meet their Resource Adequacy Requirement (RAR) at the time of national peak.

12.8. Distribution licensees shall keep the share of Long-Term contracts in the range of 75%-80% of the Resource Adequacy Requirement (RAR) and Medium-Term contracts in the range of 10%-20% of the RAR while the rest is to be met through Short-Term contracts.

Provided that power procurement through exchange shall not be considered towards the contribution for meeting RAR.

12.9. The contract mix mentioned under Regulation 12.8 of these Regulations may be reviewed by the Commission.

12.10. Distribution licensees 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 the national peak. Only resources with Long-Term, Medium-Term and Short-Term contracts shall be considered to contribute to the RAR.

12.11. For the subsequent three years, the distribution licensees shall submit a plan to meet the estimated requirement of their contribution to the national peak for the Commission's approval.

12.12. Distribution licensees shall submit the LT-DRAP plan vetted by CEA along with details for meeting RAR of its contribution to the national peak to the Commission within 15 days from the date of receipt of CEA approval.

12.13. Distribution licensees, through the LT-DRAP, shall also 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, including power exchanges. Distribution licensees shall keep the share of Long-Term contracts in the range of 75%-80% of the Peak demand and Medium-Term contracts in the range of 10%-20% of the Peak demand while the rest is to be met through Short-Term contracts.

12.14. The share of Long-Term contracts of distribution licensees shall not be less than higher of the quantum obtained in Regulation-12.8 and 12.13.

12.15. Distribution licensees shall submit the details of the contracted capacities for the ensuing years for meeting RAR of the national peak to SLDC within 15 days from the date of approval from the Commission.

12.16. SLDC shall aggregate the total contracted capacities at the state level and submit the information to NRLDC.

12.17. SLDC shall prepare a one-year look ahead ST-DRAP on an annual basis for operational planning, at the state level based on the LT-DRAP study results. The SLDC shall review the ST-DRAP on a daily, monthly and quarterly basis, based on the actual availability of generation resources.

12.18. The Commission shall approve MT-DRAP and ST-DRAP of the distribution licensees 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 peak or National RA requirement as determined by Authority or the NLDC or the RLDC , as the case may be

Chapter 5
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 lay emphasis on the 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 to avoid stranding of assets. The distribution licensee shall adopt the least cost modelling and optimization techniques and demonstrate the same in its overall power procurement planning exercise to be submitted to the Commission for approval.

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

15. Procurement Type and Tenure

15.1. The distribution licensees shall identify the generation resource mix and procurement strategy in long-term, medium-term and short-term horizons and seek approval of the Commission.

15.2. Distribution licensee through Annual Rolling Plan shall ascertain incremental capacity addition requirement through Long-Term/Medium Term/Short-Term upon factoring in its own existing and planned procurement initiatives.

15.3. The distribution licensee must ensure that the procurement process for the projected demand is undertaken and completed sufficiently in advance so that the procured capacity becomes available when it is required to serve the projected load. The following table gives the number of years before which procurement process must be completed in advance as compared to the year of projected requirement for various types of generation and types of procurement:

Resource	**Long Term**	**Medium Term**
Coal/Lignite	7	2
Hydro	9	2
Solar	2	1
Wind	3	1
PSP	5	3
Other Storage	2	1
Nuclear	9	3

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 shall utilize the platform for inter-state capacity sharing or trading mechanism created by the Central Commission/ Central Government to optimize the capacity costs as far as possible.

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

16.3. The distribution licensee and the SLDC shall seek approval from the Commission for the procurement plan as well as Annual Rolling Plans.

17. Approval of Power Purchase Agreement

17.1. 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.

17.2. Any new Capacity arrangement/tie-up /power purchase agreement for Long/Medium/Short-term or amendments to existing Long/Medium/Short-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.

17.3. The distribution licensee shall submit the list of all existing Power Purchase Agreements 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 the following reasons:

18.1.1. 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.

18.1.2. 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.

18.2. No prior approval of the Commission shall be required for power purchase under Reg-18.1.

Provided that the details of such Short-term procurement shall be submitted to the Commission within 45 days from the 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, SLDC shall communicate the state-aggregated capacity shortfall to the State Commission by 30th September of each year for the ensuing year(s) and advise the distribution licensees to commit additional capacities.

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

19.3. The Commission may, by a separate order, prescribe non-compliance charges applicable for the shortfall for RA compliance.

Chapter 7

Roles and Responsibilities and Timelines

20. Data Requirement and Sharing Protocol

20.1. Distribution licensees shall maintain and share with SLDC 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 and share with SLDC all statistics and database pertaining to 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 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 (Distributed Energy Resources), EVs and OA, National Hydrogen Mission, reduction of T&D losses, etc.

20.3. Distribution Licensee shall maintain and share with SLDC 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.

20.4. SLDC shall maintain the licensee-specific as well as aggregate for state as a whole, statistics and database pertaining to aggregate demand assessment and forecasting data as mentioned above and share state-level assessment with the Authority and the NLDC for regional/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 with SLDC for computation of state-level capacity credit factors and for preparation of state-level assessment of Resource Adequacy requirement.

20.6. UPPCL may perform the Resource Adequacy exercise on behalf of State-Owned Distribution Licensees but demand assessment shall be done separately for each licensee.

21. Timelines

21.1. Distribution licensees shall submit demand forecasts to SLDC by 30th April of each year for the ensuing year(s).

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

21.3. SLDC shall allocate each Distribution Licensee's share in the national peak within 15 days of publications of LT-NRAP report of each year for the ensuing year(s).

21.4. Distribution Licensee shall submit LT-DRAP plan to CEA by 30th September of each year for the ensuing year(s) for validation.

21.5. Distribution licensee shall submit the LT-DRAP plan duly vetted by CEA along with details for meeting the RAR to the Commission within 15 days from the date of receipt of CEA approval.

21.6. Distribution licensees shall submit MT-DRAP and ST-DRAP along with LT-DRAP to the Commission for approval.

21.7. The Commission shall approve the Resource Adequacy Plan submitted by Distribution licensees within 60 days from the date of submission.

21.8. Distribution licensees shall submit the details of contracted capacities for the ensuing year for meeting RAR to SLDC within 30 days from the date of approval of the Commission.

21.9. SLDC shall submit state-level aggregated plan to NLDC, under intimation to the Commission, within 15 days from the date of receipt by last distribution licensee.

21.10. The contracting for balance capacity shortfall as communicated by NLDC shall be completed by the end of March of each year for the ensuing year(s) by distribution licensees.

21.11. Distribution licensees, after contracting the balance capacity shall submit the information to the Commission by 1st April of each year for the current year(s).

Provided that in case there is a delay in communication by NLDC for balance capacity shortfall, the distribution licensee may seek approval from the Commission for a time extension for contracting the balance capacity by 25th March of each year.

Chapter 8 Miscellaneous

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 licensees and SLDC within 15 days of such procurements/sale with ease of access to the current as well as archived data.

23. Constitution of dedicated cells by Distribution Licensee

23.1. The Distribution Licensees 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 (Software programs such as ORDENA/PLEXOS) for demand forecast, capacity, RE integration etc using other methodologies whether probabilistic or not.

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

Provided that a centralized dedicated cell may be constituted by UPPCL on behalf of all State owned Distribution Licensees.

24. Power to issue Directions

24.1. If any difficulty arises in giving effect to these Regulations, the Commission may on its own motion or on an application filed by any affected party, issue such directions as may be considered necessary in furtherance of the objective and purpose of these Regulations.

25. Power to Relax

25.1. 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 by grant of relaxation, may relax any of the provisions of these Regulations on its own motion or on an application made before it by an interested person.

26. Power to Remove Difficulties

26.1. 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.

(Secretary)

UPERC

UTTAR PRADESH ELECTRICITY REGULATORY COMMISSION

EXPLANATORY MEMORANDUM (EM)

On

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

June 2024

Table of Contents

Abbreviations

AT&C	:	Aggregate Technical & Commercial
CEA	:	Central Electricity Authority
CERC	:	Central Electricity Regulatory
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
MoP	:	Ministry of Power
MT	:	Medium-Term
MT-DRAP	:	Medium-Term Distribution Resource Ade
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
STU	:	State Transmission Utility
ToR	:	Terms of Reference
UPERC	:	Uttar Pradesh Electricity Regulatory
WG	:	Working Group

Introduction

Uttar Pradesh is the most populous state in India. Its peak demand and energy requirement are both projected to grow steadily over the next few years. On the supply side, the share of renewable energy (RE) in its installed capacity is also going to rise rapidly.

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 maximize utilization 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 utilization.

Existing Institutional Frameworks

In December 2022, the Ministry of Power (MoP) notified the Electricity Amendment Rules. Rule-16 of these rules pertains to Resource Adequacy:

16. Resource Adequacy.—(1) A guideline for assessment of resource adequacy during the generation planning stage (one year or beyond) as well as during the operational planning stage (up to one year) shall be issued by the Central Government in consultation with the Authority, within six months from the date of commencement of these rules.

(2) The State Commission shall frame regulations on resource adequacy, in accordance with the guidelines issued by the Central Government and the model Regulations framed by Forum of Regulators, if any, the distribution licensees shall formulate the resource adequacy plan in accordance with these Regulations and seek approval of the Commission.

(3) The State Commission shall review the resource adequacy, for each of the distribution licensees, as per the time line given in resource adequacy guidelines issued by the Central Government.

(4) The State Commission may determine non-compliance charges for failure to comply with the resource adequacy target approved by the Commission.

(5) The National Load Dispatch Centre and the Regional Load Dispatch Centres shall carry out assessments of resource adequacy, for operational planning, at the national and regional levels, respectively, on an annual basis, in accordance with the guidelines issued by the Central Government.

(6) The State Load Despatch Centre shall carry out assessments of resource adequacy, for operational planning, at the state level, in consultation with all the concerned stakeholders on an annual basis,in accordance with the guidelines issued by the Central Government and the directions of the State Commission.

(7) The State Load Despatch Centre shall review the operational resource adequacy on a daily, monthly and quarterly basis.

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

Considering all of above documents, UPERC has notified the Draft Uttar Pradesh Electricity Regulatory Commission (Framework for Resource Adequacy) Regulations, 2024.

The Draft Uttar Pradesh Electricity Regulatory Commission (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, 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. 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, rooftop solar schemes, 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.
4. Further, while undertaking demand forecasts, the distribution licensee shall take into consideration the impact and benefits arising out of the demand side management programs and DSM plans, energy efficiency measures,

energy conservation interventions etc.

Based on the collection of comprehensive inputs, DLs should apply scientific and mathematical methodologies with the best fit to forecast demand at minimum hourly granularity and for a 1-year, 5-year and 10-year period. SLDC will then compile comprehensive inputs received from all DLs and independently create a state-level demand forecast with minimum hourly granularity for a 1-year, 5-year and 10-year period.

Regulation-6.13 of the Draft Regulations proposes that DLs shall add distribution loss as per their own expected loss trajectory to the category-wise demand forecast obtained to obtain their energy requirement. Provided that distribution loss trajectory as approved by the Commission shall be used for True-Up, APR and ARR purposes.

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.

2.1 Capacity Crediting

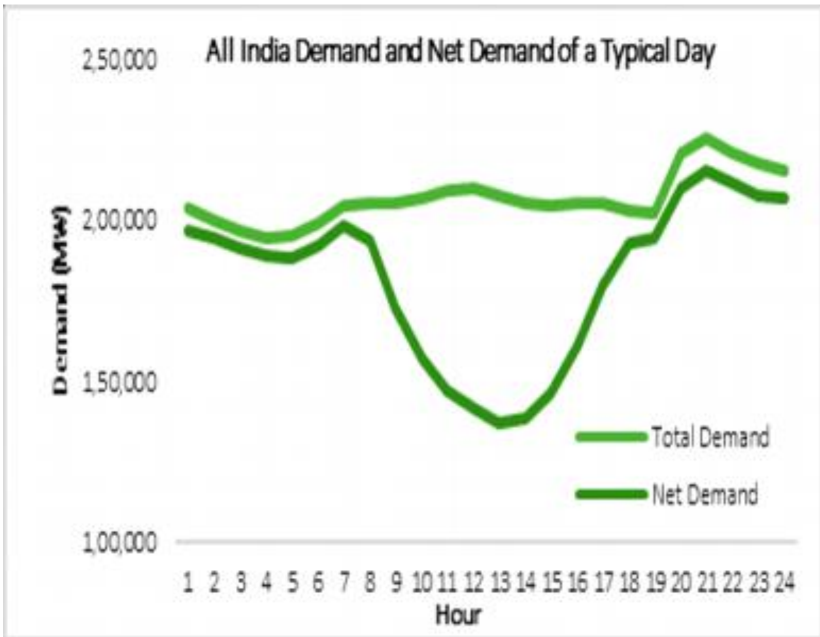
The Capacity Credit (CC) of a generating technology represents the amount of power it can reliably provide. The capacity credit is measured either in terms of physical capacity (kW, MW, or GW) or the fraction of its nameplate capacity (%). Capacity crediting (CC) ensures that the generation resources 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.

Following are the various methodologies to determine capacity credits of Renewable energy adopted internationally:

1. **Capacity credit approximation with Top Demand Hours:** In this case, a basic approximation of capacity credit can be obtained by averaging the historical contribution of a generator / generator class during peak demand hours. The selection of how many peak demand hours to include, however, often varies across geographies.

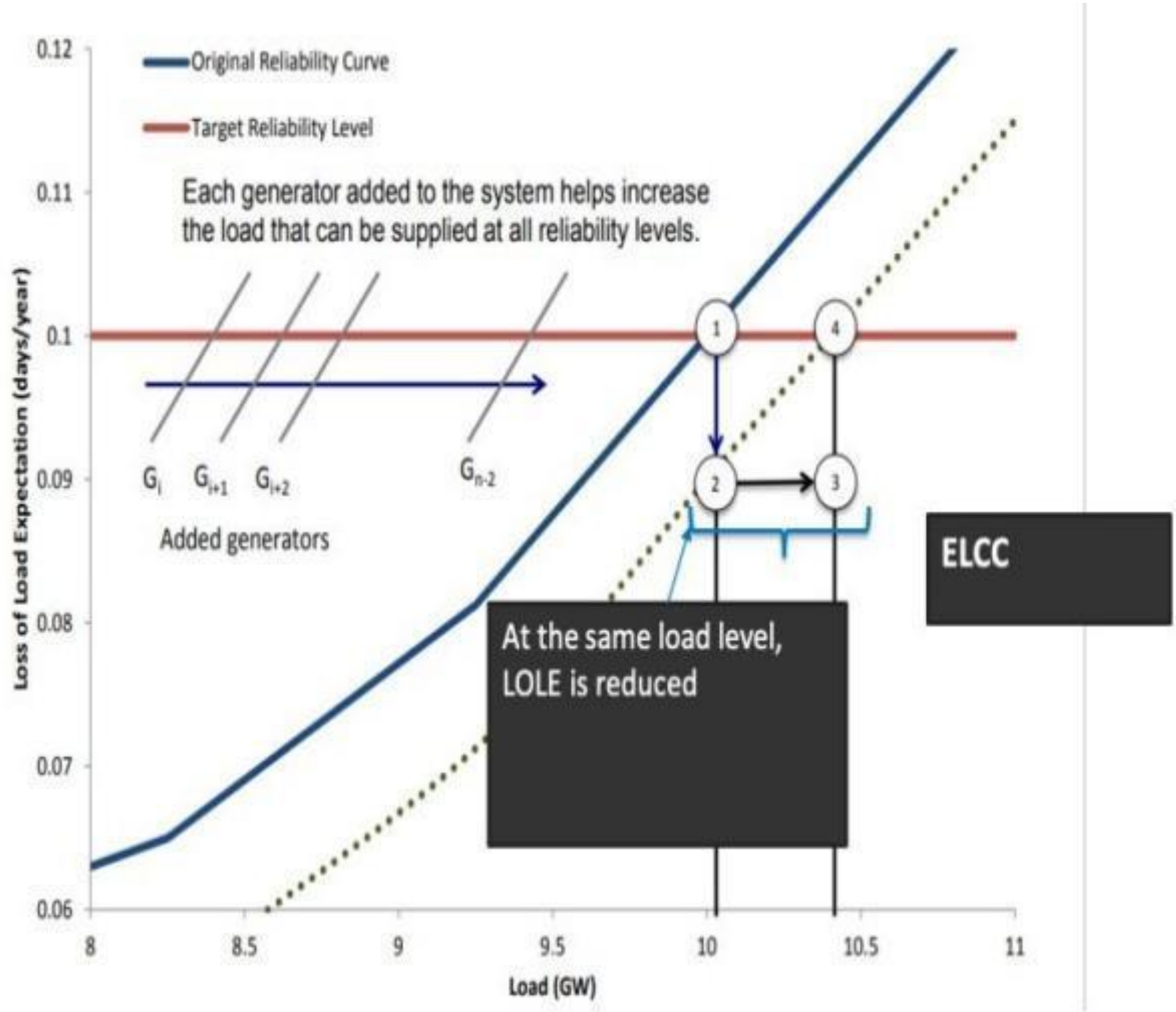
2. **Capacity credit approximation with Top Net Load Hours:** In this case, consideration is given to the fact that periods of system stress occur when high demand coincides with low renewable energy generation. A metric called ‘net load’ is defined as ‘total renewable energy generation subtracted from overall demand’, which must be met from dispatchable resources like

thermal plants, hydro plants, etc. Due to system stress caused by the duck curve, net load is a better proxy for system stress for new capacities than peak demand. In this method, capacity credit can be obtained by averaging the contribution of a generator / generator class during top net load hours.



3. **Expected Load carrying capability:** In this method, a model uses an hourly time- series demand data for a particular period. The model also uses the availability of different generation resources in each hour of the year. Random outages of generators are also applied considering the historical and expected outage conditions. Determine supply matching is used to determine the LOLP of the system.
    a. To calculate capacity credit, the model first removes a generator from the system and calculates the system LOLP. This represents Point 1 in the system reliability curve, as shown in the figure.
    b. The model then adds the generator back to the system and repeats the LOLP calculation. The additional generator increases system-wide firm capacity and resource adequacy, so the curve shifts right to Point

2 (system reliability is higher), and so it can accommodate more load at the previous LOLP (Point 4). The additional load that can be accommodated represents the generator's ELCC.



As part of the Regulation 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 hourly recorded Gross Load for 8760 hours (or time-block) shall be taken.

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.

3. Installed capacity is summed up corresponding to the top 250 hours.

4. Total solar or wind generation is summed up corresponding to the top 250 hours.

5. 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 the impact of changes in installed capacities, demand profile, and generation profile on CC is duly factored.

The following input data should be used:

1. Annual peak (MW) and energy (MWh) projections for 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 the 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 hydropower projects should be different from those of dam-based/storage-based hydropower 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.

The calculation of firm capacity to meet the Resource Adequacy Requirement (RAR) is shown below:

$$
\begin{aligned}
RAR = & \sum_{i=1}^{num\_solar} Solar\_Capacity * Solar\_Capacity\_Credit \\
& + \sum_{i=1}^{num\_wind} Wind\_Capacity * Wind\_Capacity\_Credit \\
& + \sum_{i=1}^{num\_hydro} Hydro\_Capacity * Hydro\_Capacity\_Credit \\
& + \sum_{i=1}^{num\_thermal} Thermal\_Capacity * Thermal\_Capacity\_Credit \\
& + \sum_{i=1}^{num\_nuclear} Nuclear\_Capacity * Nuclear\_Capacity\_Credit \\
& + \sum_{i=1}^{num\_storage} Storage\_Capacity * Storage\_Capacity\_Credit \\
& + \sum_{i=1}^{num\_other} OtherResource\_Capacity * OtherResource\_Capacity\_Credit \\
& + \sum_{i=1}^{num\_other} Import\_limit * capacity\_credit
\end{aligned}
$$

2.2 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. MOP/CEA's 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 per Regulation 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.

2.3 RA Requirement and Allocation

The Central Electricity Authority shall publish Long-term National Resource Adequacy Plan (LT-NRAP) which shall determine the optimal Planning Reserve Margin (PRM) requirement at the All-India level conforming to the reliable supply targets.

a) The report shall publish the national-level PRM as a guide for all the States/UTs to consider while undertaking their RA exercises.

b) The report shall also publish the Optimal Generation mix for the next 10 years required to ensure that the national-level system is RA compliant while meeting the All-India demand at least-cost. This shall guide capacity buildout investments in the country.

c) The report shall also publish the capacity credits for different resource types on a regional basis.
d) The report shall specify the State/UT's contribution towards the national peak.
e) The LT-NRAP shall be updated annually.

Based on the share in national peak provided in LT-NRAP, each distribution licensee shall plan to contract the capacities (peak contribution * (1 + National level PRM)) prescribed by LT-NRAP or higher to be procured to meet their Resource Adequacy Requirement (RAR) at the time of national peak.

The distribution licensees shall demonstrate to the UPERC 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 the national peak. Only resources with long/medium/short-term contracts shall be considered to contribute to the RAR.

For the subsequent three years, the distribution licensees shall furnish a plan to meet the estimated requirement of their contribution to meet the national peak for SERC approval.

Each Distribution licensee shall undertake a Resource Adequacy Plan (RAP) for a 10-year horizon (Long-term Distribution Licensee Resource Adequacy Plan (LT-DRAP)) to meet their own peak and electrical energy requirement. The plan shall be vetted/validated by Central Electricity Authority for leveraging the benefit of national-level optimization for the Distribution licensees.

Distribution licensees, through the LT-DRAP, shall also demonstrate to the UPERC, their plan to meet their Peak demand and energy requirement with a mix of long-term, medium-term and short-term contracts, including power exchanges. The composition of the contracts will depend upon the load curve of each distribution utility.

The share of long-term contracts is suggested to be in the range of 75-80% of the total supply side RAR. The medium–term contracts are suggested to be in the range of 10% - 20% of the total supply side RAR while the rest can be met through short-term contracts.

Power procurement through the power exchanges, such as the Day-Ahead Market segment, shall not be considered to contribute to RAR for DL's share in the national peak demand. But the same shall be allowed to meet DL's own peak demand.

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.

3.1 Procurement Resource Mix

Based on the 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) 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:

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

years

b. Hourly profile for the previous five years

7. 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 licensees should undertake such energy modelling exercises to compute the least-cost resource mix to meet their allocated RA requirement.

3.2 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 Regulation 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.

3.3 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, 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 Regulation 20 of the Draft RA Regulations, the following timelines should be followed:

1. Distribution licensees shall submit demand forecasts to SLDC by 30th April of each year for the ensuing year(s).
2. SLDC shall aggregate and submit state-level demand forecasts to the Authority and the NLDC by 31st May of each year for the ensuing year(s).
3. SLDC shall allocate each Distribution Licensee’s share in the national peak within 15 days of publications of LT-NRAP report of each year for the ensuing year(s).
4. Distribution Licensee shall submit LT-DRAP plan to CEA by 30th September of each year for the ensuing year(s) for validation.
5. Distribution licensee shall submit the LT-DRAP plan duly vetted by CEA along with details for meeting the RAR to the Commission within 15 days from the date of receipt of CEA approval.
6. Distribution licensees shall submit MT-DRAP and ST-DRAP along with LT-DRAP to the Commission for approval.
7. The Commission shall approve the Resource Adequacy Plan submitted by Distribution licensees within 60 days from the date of submission.
8. Distribution licensees shall submit the details of contracted capacities for the ensuing year for meeting RAR to SLDC within 30 days from the date of approval of the Commission.
9. SLDC shall submit state-level aggregated plan to NLDC, under intimation to the Commission, within 15 days from the date of receipt by last distribution licensee.
10. The contracting for balance capacity shortfall as communicated by NLDC shall be completed by the end of March of each year for the ensuing year(s) by distribution licensees.
11. Distribution licensees, after contracting the balance capacity shall submit the information to the Commission by 1st April of each year for the current year(s).