F. No.09/01/2021-RCM
Government of India
Ministry of Power
(RCM Division)
***

Shram Shakti Bhawan, Rafi Marg,
New Delhi, the 28th June, 2023

To

1. ACS/Principal Secretaries/Secretaries (Power/Energy) of all State Governments/UTs.
2. CMD/MDs of State Gencos/ Discoms
3. All Central Power Sector Utilities

Sub: Guidelines for Resource Adequacy Planning Framework for India-reg.

Sir/Madam,

The Ministry of Power has issued Electricity (Amendment) Rules, 2022 on 29th December, 2022.

2. In exercise of the powers conferred under the Rule 16 of Electricity (Amendment) Rules, 2022, the Guidelines for Resource Adequacy Planning Framework for India, framed in consultation with Central Electricity Authority (CEA), are hereby issued. The guidelines are placed at **Annexure**.

3. These guidelines shall be followed by all the institutions and stakeholders, who shall ensure sufficient tie up of capacities to meet resource adequacy requirements on different time horizons.

4. This issues with the approval of **Hon'ble Minister of Power and New & Renewable Energy.**

Yours sincerely,

Encl: As above

Hemant
28/06/23

(Hemant Kumar Pandey)
Chief Engineer (R&R)
Tel. No. 011-23710389

Copy to:

1. Secretary, Ministry of New & Renewable Energy, New Delhi
2. The Chairperson, CEA, New Delhi
3. The Secretary, CERC, Chanderlok Building, Janpath, New Delhi
4. Secretaries of All State Electricity Regulatory Commissions/JERCs

Copy for information to:

1. PS to Hon'ble Minister of Power and NRE
2. APS to Hon'ble Minister of State for Power & Heavy Industries
3. Sr. PPS to Secretary(P)/ PPS to SS&FA/ PPS to AS (EC&ET/Hydro)/ PPS to JS (Thermal/Distribution)/ PPS to JS (Trans)/ PPS to JS (Hydro) / PPS to EA/ PPS to CE (OM)
4. All DS/Directors, Ministry of Power
5. Technical Director, NIC (with the request to publish it on Ministry of Power's website)

ANNEXURE

GUIDELINES

FOR

RESOURCE ADEQUACY PLANNING

FRAMEWORK FOR INDIA

(Framed under the Rule 16 of Electricity (Amendments) Rules, 2022)

JUNE 2023

INDEX

In exercise of the powers conferred under the Rule 16 of Electricity (Amendment) Rules, 2022, the Ministry of Power, Government of India, in consultation with Central Electricity Authority (CEA) hereby issues the guidelines for Resource Adequacy for the Indian electricity sector. These guidelines shall be followed by all institutions and stakeholders, as provided in these guidelines.

SECTION – 1

Introduction

1.1. For the past few years, India has been the fastest growing large economy in the World; and the growth will continue. Currently, it is the fifth largest economy in the World; and it is poised to become the third largest economy by 2030. This will only be possible if there is sufficient electricity to power this growth. It is essential that generation capacity is added at a pace matching the growth in demand- and in fact slightly ahead of the demand; so that the shortage of electricity does not slow down growth. Resource Adequacy planning is designed to ensure this. The guidelines aim to achieve the following key objectives:

1.1.1. Energy for growth: It is necessary to timely add adequate generation capacity to meet the projected demand while maintaining necessary reserves.

1.1.2. It is incumbent upon the DISCOMs to supply 24 X 7 reliable power to its consumers. All DISCOMs are duty bound to tie up sufficient capacity to meet the demand of its consumers. If any DISCOM does not do so, it is failing in its duty. Compliance to the Resource adequacy norms and Guidelines shall ensure that DISCOMs tie up sufficient capacity to meet the demand of the area they are licensed to serve. Rights of Electricity Consumers Rules, 2020 prescribe payment of compensation to consumers for avoidable load shedding.

1.1.3. The capacity which the DISCOMs tie up shall be a judicious mix of long/medium and short term contracts to ensure security of supply to their consumers at least cost. Over reliance on the electricity market is to be avoided.

1.1.4. As a part of its Nationally Determined Contributions (NDCs) to combat climate change, India has pledged that by 2030 it will have 50 percent of its power generation capacity coming from non-fossil sources. Accordingly, all obligated entities must fulfil their Renewable Purchase Obligation (RPO). Compliance with RPO will also include compliance with targets for Roof top solar and other Distributed Renewable Energy segments.

1.2. Resource Adequacy means tying up sufficient capacity to reliably serve expected demand of the consumers in the DISCOMs license area in a cost effective manner. Reliability is measured through the instances/probability of system peak exceeding the contracted capacity that is effectively available at a National/State level. The guidelines aim to establish a Resource Adequacy framework for power procurement by distribution licensees, ensuring a reliable operation of the power system across all timeframes. The Resource Adequacy exercise will assess the required capacity to be contracted on long term, medium term, and short-term basis. A key aspect of resource adequacy planning is to ensure that adequate generation capacities are available, round-the-clock, to reliably serve demand, under various scenarios. This translates into requirement of an adequate reserve to cater to varying levels of demand and supply conditions prevailing in the grid.

1.3. The resource adequacy framework lays down the optimal capacity mix required to meet the projected demand at minimum cost. New generation capacities, energy storage and other flexible resources needed to reliably meet future demand growth at optimal cost to the system will be timely assessed. It must also incorporate likely retirement of existing capacity on account of completion of economic life.

1.4. Procurement actions according to Resource Adequacy framework must be taken up timely by DISCOMs so that generation capacity becomes available well before its requirement to meet projected growth.

1.5. The implementation of these guidelines shall be ensured by the Appropriate Commission.

SECTION – 2

Resource Adequacy Plan to arrive at optimal capacities in the long-term and fulfil Resource Adequacy

2.1 The DISCOM will draw up the demand profile; the demand growth rate; the present contracted capacity and the quantity being procured from the Power Exchanges. The plan shall be drawn up keeping in view the fact that gratuitous load shedding entails penalties as per the present Rules-therefore load shedding is not an option.

2.2 The plan will undertake a least cost generation optimization to meet the demand such that it minimizes the overall system cost - including operations and maintenance costs, costs to procure spinning reserves, fuel costs, start-up, and shut-down costs of generating units. The optimization includes all constraints related to power plant operations like ramp-up / ramp-down limits, start-up/ shut-down limits and their costs, generation limits, energy storage operations, interconnection limits (import/export), renewable addition(RPO) targets, Solar Rooftop/ distributed generation capacities, retirement schedules of existing generation plants, planning reserve margin etc. The Resource Adequacy exercise shall have a planning horizon of 10 years on a rolling basis.

2.3 A consideration to include energy storage and other flexible resources, which is necessary in balancing out the variability and intermittency of RE, should be included for increasing reliability and reducing system costs.

2.4 Resource adequacy shall be determined based on the resource availability and accessibility after taking into account the possibility of sharing of resources from other utilities/ states.

2.5 The Resource Adequacy Plan will lay down the **quantum and type of resources** required in the portfolio of a distribution licensee to meet the demand in an optimal (least cost and secure) manner. The plan shall give the **year-on-year optimal generation** (conventional plus Renewable) and **storage capacities required to meet the system demand** and the **planning reserve margin** securely and at least cost.

2.6 The data requirements and methodology for preparation of Resource Adequacy Plan have been provided as Annexure E.

SECTION – 3

Institutional mechanism for Resource Adequacy and Compliance Monitoring

3.1 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 guidance 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 national peak.

e) The LT-NRAP shall be updated annually.

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

3.3 The hourly demand forecasts used by CEA and NLDC shall be aligned with the projections furnished by individual Distribution Licensees to CEA and NLDC. The STU / SLDC, on behalf of the distribution licensees in the State shall provide to CEA and NLDC by the month of May every year, the details regarding demand forecasts (peak and energy requirement) for the next 10 years, assessment of existing generation resources and such other details as may be required for the LT-NRAP and ST-NRAP.

3.4 The LT-NRAP and ST-NRAP shall be published by the month of July for the period starting from the month of April in the subsequent year.

3.5 The LT-NRAP shall allocate the share in national peak for each state. In States/UTs where there are multiple distribution licensees, the respective STU / SLDC shall allocate each distribution licensee's share in the national peak within 15 days of the publication of LT-NRAP.

3.6 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 SERC/JERC 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 national peak. Only resources with long / medium / short-term contracts shall be considered to contribute to the RAR.

The share of long-term contracts is suggested to be in the range of 75-80%[1] of the total supply side RAR, or as specified by the respective SERC/JERC. 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. However, these ratios of long, medium and short term contracts may be reviewed periodically based on further experience.

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

3.7 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. The LT-DRAP shall be undertaken as per the methodology outlined in Annexure-E of these guidelines.

3.7.1 The distribution licensees shall take inputs if required from the LT-NRAP like PRM, capacity credits, etc., while formulating their LT-DRAP and submit their plans to CEA by the month of September for the period starting from the month of April in the subsequent year.

[1] This value is subject to change from time to time, as guided by CEA

3.7.2 After being vetted by CEA, the plan LT-DRAP along with details for meeting the RAR of national peak for the utility may be submitted to SERC/JERC by the month of November for the period starting from the month of April in the subsequent year for their approval.

3.7.3 Distribution licensees are free to consider higher planning reserve margins, subject to approval from the SERC/JERC.

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

3.8 Distribution licensees, through the LT-DRAP, shall also demonstrate to the SERC/JERC, 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 atleast 75% of the required capacities as per LT-DRAP or as specified by the respective SERC/JERC. The medium–term contracts are suggested to be in range of 10-20% while the rest can be met through short-term contracts. Distribution licensees shall also demonstrate their plans to contract existing capacities and plans to build or contract future capacity for the planning horizon.

3.9 The share of long-term contracts in the entire mix of the contracts of the utility shall be atleast the maximum of the quantum of long term contracts determined for meeting RAR of national peak and quantum obtained from LT-DRAP for fulfilling own energy and peak requirement.

3.10 The Distribution Licensee shall submit the details of the contracted capacities for the ensuing year for meeting RAR of national peak to the respective STU / SLDC after approval of respective SERC/JERC by the month of January. The STUs / SLDCs shall aggregate the total contracted capacities at the state level and submit the information to the respective RLDC. The RLDCs shall aggregate the capacities at the regional level and submit the information to the NLDC by the month of February. NLDC shall aggregate the capacities at the national level and check compliance with ST-NRAP and identify shortfall for the ensuing year, if any. In case of shortfall, NLDC shall either communicate the shortfall to the SERC/JERC for compliance or facilitate a national-level auction for the balance capacity[2] with participation from distribution licensees with capacity shortfall[3]. The

---

[2] $balance\ capacity = (1 + National\ PRM) \times NationalPeak\ - sum\ of\ contracted\ capacities$

contracting for the balance capacity shortfall shall be completed by the month of March prior to the start of the delivery year (1st April). NLDC shall come out with a methodology to carry out national level auction for the procurement of the balance capacity.

3.11 The STUs/SLDC shall prepare one-year look ahead ST-DRAP (Short term Distribution Resource Adequacy Plan), 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 actual availability of generation resources.

3.12 In terms of Section 86(1)(b) of the Electricity Act, 2003, the Appropriate Commission may ensure the compliance of Resource Adequacy Planning by the distribution licensees. The Appropriate Commission may also specify the non-compliance charges."

3.13 The CERC in consultation with the Forum of Regulators (FOR) may come out with model regulations for implementing the resource adequacy process in the States/UTs and the distribution utilities.

3.14 A schematic illustrating the Resource Adequacy implementation timelines is given in **Annexure F**.

---

[3]

$$capacity\ shortfall = (1 + National\ PRM) \times Licensee\ Demand\ during\ National\ Peak\ - sum\ of\ contracted\ capacities\ by\ the\ licensee$$

Section 4

Guidelines for Procurement of Required Resources

4.1 The outcome of the Resource Adequacy Studies would provide the **quantum and type of generation resources** required in the portfolio of a distribution licensee to meet the demand in an optimal (least cost and secure) manner. The future capacity mix may comprise of existing capacities, planned capacities and capacity addition required to meet the increasing demand of the utility considering appropriate gestation period of the generation resource.

4.2 The distribution licensee shall contract the optimal portfolio of resources to meet its future demand and Resource Adequacy Requirement (RAR) obligations, based on the output derived from the LT-NRAP study results. Long / medium / short-term firm contracts of generation resources shall be considered to contribute to the RAR. Power procurement through the power exchanges, such as the Day-Ahead Market segment, shall not be considered to contribute to RAR.

4.3 The distribution licensee shall contract additional resources source-wise if required based on the LT-DRAP to meet its own peak demand.

4.4 The states can either put up their own generation capacities for meeting their future demand or the respective state distribution licensee shall procure the required resources through the tariff based competitive bidding guidelines for procurement of power notified under the provisions of section 63 of the Electricity Act 2003.

4.5 The power capacity procurement from renewable energy sources for fulfilling the RPO targets shall be carried out taking into account the RE potential in that State and fungibility within the RE resources as per the latest RPO order. The power procurement corresponding to wind, solar PV, Wind solar Hybrid, Round the Clock (RTC) power shall be carried out as per the guidelines for tariff based competitive bidding process for procurement of power from respective grid connected wind, solar PV, Wind solar Hybrid, Round the Clock (RTC) power projects.

4.6 The Distribution Licensee can contract storage capacity corresponding to the results of LT-DRAP capacity addition requirement for future years as per the guidelines issued under the provisions of Section 63 of the Electricity Act, 2003 for procurement of energy from BESS through competitive bidding, from grid connected Projects.

4.7 The Distribution Licensee can contract power through Central Agencies / Intermediaries / Traders / Aggregators / Power Exchanges or through bilateral agreements / Banking arrangement with other distribution licensees. The Distribution Licensee can carry out power procurement on short-term and medium term basis through DEEP and PUShP portal.

4.8 The distribution licensee must ensure that 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 Based Capacity	7	2
Hydro	9	2
Solar	2	1
Wind	3	1
PSP	5	3
Other Storage	2	1
Nuclear	9	3

ANNEXURE A

Key design parameters for RA framework

- **Reliability** is key to power systems operations and hence adequacy of supply needs to be maintained at all points in time. There could be unavoidable outages, due to unforeseen circumstances and reasons, but the resource adequacy planning should be such that these outages (loss of load events) are minimized..
- **Loss of Load Probability (LOLP)** is a measure of the probability that a system's load may exceed the generation and firm power contracts available to meet that load in a year

Parameter	Definition
Loss of Load Probability (LOLP)	Measure of the ***probability that a system's load may exceed the generation*** and firm power contracts available to meet that load in a year. E.g., 0.0274 % probability of load being lost.

- Additionally, another metric which could be utilized in conjunction with LOLP is the **Expected Energy Not Served (EENS).**

Parameter	Definition
Expected Energy Not Served (EENS)	Expected amount of energy (MWh) that may not be served for each year within the planning period under study. It is a summation of the expected number of megawatt hours of demand that may not be served for the year. This is an energy-centric metric that considers the magnitude and duration of energy being not served, calculated in MegaWatt hours (MWh). The metric can be normalized (i.e., divided by total system load) to create a Normalized Energy Not Served (NENS) metric.

- "Normalized ENS(NENS)" is the total expected load shed due to supply shortages (MWh) as a percent (%) of the total system energy, and therefore represents an overall percentage of system load that cannot be served.
- Most systems in advanced electricity markets use LOLP / NENS as the RA planning criteria.
- To meet the prescribed standard of LOLP / NENS conditions, sufficient reserve margins need to be maintained in the system for adequately addressing the demand and supply variations. **Planning Reserve Margin (PRM)** is the predominant metric used to ensure adequacy of

generation resources in the system. PRM in a power system is expressed as a certain % of peak load forecast of the system.

- CEA, from time to time, publishes the desired values for reliability indices such as LOLP and NENS required for resource adequacy in India and accordingly estimate the PRM required to be maintained optimally at the national level. The LOLP and NENS values adopted by CEA for the purposes of the National Electricity Plan (NEP) are 0.2% and 0.05%, respectively.

  Similarly, system studies can be undertaken by the utilities to determine the PRM through any scientific method, provided the reliability criteria (LoLP and NENS) are more stringent or as guided by CEA from time to time[4]. The methodology for conducting the Optimal Reserve Margin study is highlighted in **ANNEXURE B.**

[4] In future amendments, once the RA process is established, utilities can conduct their own reliability studies to determine the optimal level of reliability (LoLP and NENS) of supply side portfolio as per the methodology prescribed in ANNEXURE A and ANNEXURE C. In case of any shortfall, NLDC can communicate to RLDCs/SLDCs the shortfall or facilitate a national-level auction for the balance capacity with participation from distribution licensees with capacity shortfall.

ANNEXURE B

Determination of LOLP / NENS, Optimal Planning Reserve Margin (PRM) and Resource adequacy targets

- The optimal level of "target" or "planning" reserve margins should be arrived at through measures such as "Loss of Load Probability (LoLP)" and Normalized Energy Not Served (NENS). Loss of load can happen due to various factors such as:
    - Forced outages/planned maintenance of conventional generation
    - Real time unforeseen excursion in demand/demand forecast errors
    - Generation forecast errors /RE intermittency
- A loss of load occurs when the system load exceeds available in a particular time. Appropriate LOLP / NENS metrics should be considered based on consultation with stakeholders and international best practices.
- The first step in determining the Resource Adequacy targets would be to determine the target generation capacities at a nominal Planning Reserve Margin using a **generation planning** model.
- Once the generation capacities are estimated, it becomes important to estimate the several demand-supply patterns and then determine if the required generation capacity in the system can always meet demand reliably by calculating the loss of load and energy not served. A natural outcome of the above objective is to construct many possible future scenarios based on the uncertainty surrounding the demand for power, intermittency of RE sources, availability of power plants, tie-lines, inter-state and inter-regional transmission constraints etc. These future scenarios shall be constructed based on following indicative parameters viz:
    - Demand variations / forecast errors
    - Hydro conditions (normal, wet, or dry years)
    - Planned and forced outages of power plants and interconnectors
    - RE Generation forecast errors, etc.
    - **Multiple future scenarios** should be created using stochastic models to account for **uncertainty** and analyse any occurrence of lost load. Each such future scenario is

established based on historical data. The key inputs for generating future possible states are as follows:

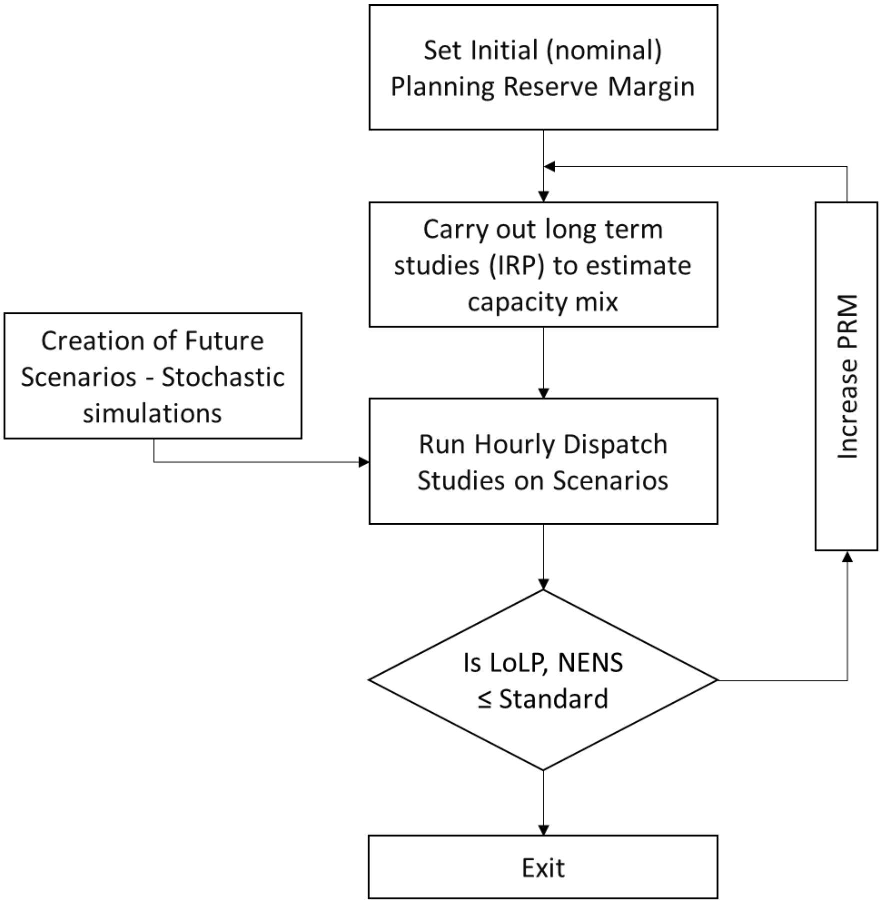
- **Demand volatility:** Uncertainty in demand can be built into the model through two categories, long-term uncertainty driven by underlying factors such as load growth forecasting errors, unanticipated economic growth, etc., and short-term uncertainty which may be defined as the sum of a typical (or mean) monthly load pattern for the day and the historical deviation observed from the mean load.
- **Conventional generator outages:** Planned outages and scheduled maintenance for thermal generators may be scheduled either based on historic patterns or during low demand periods based on a uniform probability distribution. For forced outages, Monte Carlo draws for each unit based on historical outage rates may be simulated.
- **Variable Renewable Generation Intermittency:** To capture the intermittency of solar and wind plants, PV, and wind generation data of past several years can be analysed and multiple scenarios which match the projected CUF levels may be created. Annual CUF projections may also be generated through Monte Carlo Draws based on the annual CUFs observed in the historical profiles.
- **Availability of ATC for short-term import:** In the distribution licensee-level / State-level planning, short-term import is limited to the available transfer capability. However, as there is no visibility about the power generation profile of other States, unpredictability in the availability of tie line power form other utilities and regions must be factored in. To incorporate the above-mentioned unpredictability, availability of each tie line for each hour can be derated by a factor drawn from a probability distribution using Monte Carlo Simulations. Details on the appropriate probability distribution to be considered may be provided by NLDC / CEA from time to time.

- Once the demand-supply projections / scenarios are established and the possible future states are predicted, a demand-supply matching simulation with the estimated capacities should be performed. The objective of such a simulation would be to use the capacities obtained from the Resource Adequacy Plan to meet the demand and assess the duration of the loss of load events and energy not served for each scenario and for the specified planning margin/capacity mix.
- The above process needs to be then iterated by **incrementing** the **planning reserve margin levels** until the **desired levels of LOLP / NENS** is achieved in the system. This iterative

model would enable identification of a target PRM level as per the desired LOLP figures. An illustrative flowchart of the process is shown in Figure 1.

- While arriving at the target LOLP / NENS figures, consideration should be given to system costs. The objective should be to have an optimal level of Reserve margins which would represent the optimal trade-off between system costs and reliability. For this purpose, an evaluation of the marginal cost of reducing load shed is required. The PRM at which the marginal cost of reducing load shed is equal to the Value of Lost Load as defined by the distribution licensee is the economically optimal PRM. The procedure of calculation of marginal cost of reducing load shed is given in Annexure **D**.

Figure 1: Flowchart of the Optimal Reserve Margin Study



ANNEXURE C

Determination of capacity credits for Renewable resources

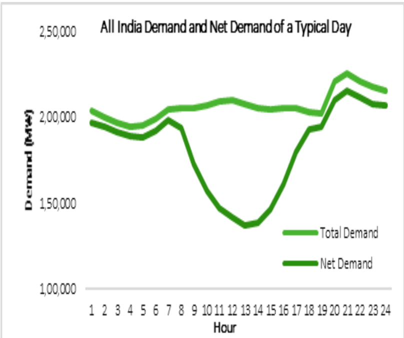
- This step is important for determining how much of energy-limited resources (hydro, wind, solar, storage) may count toward resource adequacy requirements. Generation planning is set to become more complex as larger amounts of weather-based, variable renewable generation are added to the system. This is because resources such as wind and solar PV are intermittent, and their generation may not coincide with periods of peak demand.

- Each generator can provide a "firm capacity," which represents the amount of power the generator can reliably provide. Capacity credit expresses firm capacity as a percentage of the installed nameplate capacity.

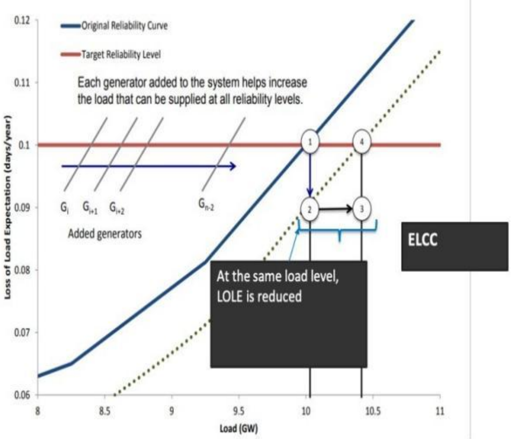
- Following are the various methodologies to determine capacity credits of Renewable energy adopted internationally. These methodologies can also be extended to demand response resources.

  a) **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.

  b) **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.



  c) **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.



- 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 alongside.
- 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.

- The Capacity Factor Approximation with Top Net Load Hours can be considered to determine the capacity credits for new resources and the Top Demand Hours methodology can be considered to determine the capacity credits for existing resources. The ELCC method can be adopted later, once the required capabilities and data are available with the state utilities.
- The utilities may plan their firm capacity as per their contribution in the national peak which implies that the capacity credits of all resource types are to be calculated on the national-level load profile.
- The calculation of firm capacity to meet the Resource Adequacy Requirement (RAR) is shown below:

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

ANNEXURE D

Marginal Cost of Reducing Load Shed

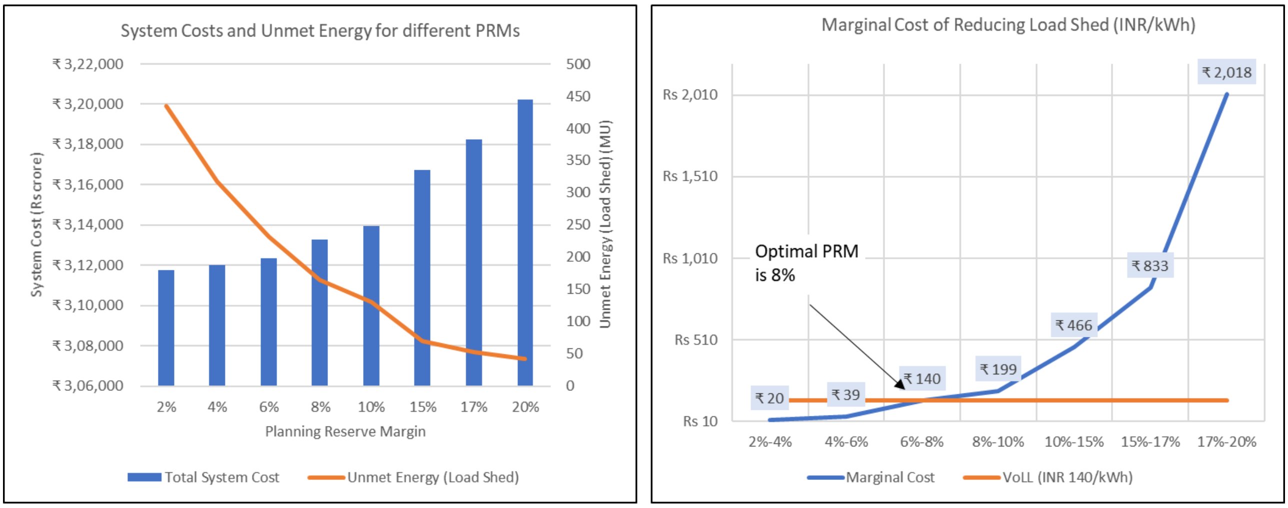
- The marginal cost of reducing load shed is the effective increase in cost for every unit of load shed reduced. It is calculated as the increase in system costs by the reduction in load shed:

$$Marginal\ Cost = \frac{System\ Cost_{PRM_{i+1}} - System\ Cost_{PRM_i}}{ENS_{PRM_i} - ENS_{PRM_{i+1}}}$$

- The economic optimal planning reserve margin is the planning reserve margin at which the marginal cost of reducing load shed is equal to the value of lost load. Utilities can rely on this planning reserve margin in case they decide to plan beyond the minimum PRM as determined by CEA.

Illustration: An illustration of the calculation of marginal costs of reducing load shed is shown in Figure 2. The capacity expansion planning model is run for different PRMs between 2% and 20%. Based on the capacities obtained, the system costs are calculated. Demand-supply matching using these capacities on future scenarios created using stochastic simulations are used to obtain the total load shed (unmet energy). Based on the system costs and unmet energy (graph on the left), the marginal cost of reducing load shed (graph on the right) is calculated using the formula in C1. Assuming a Value of Lost Load (VoLL) of INR 140/kWh, the optimal PRM would be around 8%.

Figure 2: Illustration of Calculation of Marginal Cost of Reducing Load Shed



ANNEXURE E

Methodology of Preparation of Resource Adequacy Plan

- For preparation of Resource Adequacy Plans, data on the following needs to be obtained but not limited to:
  - a) Planning Reserve Margin as prescribed by CEA or as determined by the distribution licensee and approved by the SERC/JERCs.
  - b) Actual demand met by the state / distribution licensee in granular time block resolutions (hourly) for last 5 years
  - c) Estimated load growth during the planning period
  - d) Technical parameters of conventional generation plants viz. Name of plant, location (State/Region), Capacity (MW) (for existing and planned capacities), Auxiliary Consumption (MW), Maximum and Minimum Generation Limits (MW), Ramp Up and Ramp Down Rate (MW/min), Minimum up and down time, Plant Availability Factor (% of time), etc.
  - e) Under-construction capacity/retirement of generation capacity/contracted capacity/bilateral contracts.
  - f) Potential investment options, technologies, gestation periods and lifetime of different assets.
  - g) Capacities and generation profile of renewable generation
  - h) Capital costs, variable costs, O&M costs, reserve offers, start up and shut down Cost of generators, etc.
  - i) Historical forced outage rates and planned maintenance rates of generation capacities
  - j) Tie line details and transmission expansion plans
  - k) Spinning reserve requirements
  - l) Renewable Purchase Obligation (RPO) and Energy Storage Obligation targets, etc.
- The hourly demand profile for the distribution licensee shall be projected over the planning horizon, based on the forecasted values of annual energy requirement and peak demand trajectory. The annual energy requirement and peak demand shall be forecasted using trend

method, time series, econometric methods, or any state-of-the-art methods. The projected hourly demand for the future years shall be used as inputs into the model. It shall be ensured that the generation expansion planning model chosen is capable of simulating on an hourly chronological resolution[5]. This is necessary to capture the behaviour of the system with respect to ramping of conventional generation, profiles of RE generation, behaviour of energy storage, etc.

- After establishment of demand profile for all future years, the model would undertake an optimization exercise to minimize the total system cost to meet the future demand adhering to all power system parameters. Following constraints should be considered while modelling:
  - **Planning Reserve Margin / Resource Adequacy Requirement:** The Resource Adequacy Requirement (RAR) constraint shall ensure that the total Resource Adequacy (Generation capacity) of the distribution licensee fulfils the Planning Reserve Margin as determined by CEA or by the distribution licensee's own studies and approved by the SERC/JERC. The resource adequacy requirement for each distribution licensee is computed as:

$$RAR = contribution^{6}\ to\ forecasted\ national\ peak\ demand\ in\ GW \times (1 + PRM)$$

From the supply side, the RAR is the sum of the "firm capacity" or "capacity credits" of contracted / planned capacities (including renewables, storage, other resources such as demand response) along with derated interconnection limits (imports)[7].

Both, supply side and demand side RAR shall match. The Thermal capacity credit is calculated by reducing the auxiliary consumption and the forced outage rate from the installed capacity. Planned outage rate is generally not considered, as planned maintenance may be carried out during low net-demand periods and thus may not affect reliability.

The capacity credits for generating resources and demand response resources to meet the national peak shall be estimated by CEA[8]. The capacity credits published by CEA for each resource type may differ between existing and new resources and between resources in different regions. For example, a solar based power plant in the southern

---

[5] It is preferred to simulate all 8760 hours on a chronological resolution in a year. However, if computational challenges are faced, the States/UTs can select the representative periods which may be different for each state. The representative periods chosen are reflective of various projected demand and supply profiles for the base year and future years. Initially, hourly simulation is planned based on hourly data availability, however, the time granularity may be increased to sub-hourly provided there is availability of sub-hourly demand and RE generation data.

[6] This is calculated as distribution licensee's demand at the time of national peak demand.

[7] The calculation of firm capacity is provided in Annexure C

[8] The methodologies that can be used to determine capacity credits for generating resources and demand response resources are outlined in **Annexure C.**

region will have a capacity credit which could be different compared to a solar plant in the northern region. Similarly, an upcoming wind-based power plant could have a different capacity credit compared to an already commissioned wind plant in the same region. Utilities shall use these capacity credits while planning to meet their RAR. For example, a distribution licensee having a PPA with an existing solar based power plant located in a southern state would use the capacity credit of existing solar based power plants in the southern region.

Portfolio balance constraints: The portfolio balance constraints shall ensure that the total generation within a control area of region/State/Distribution licensee and the import of power to the control area of region/State/Distribution licensee is equal to the sum of the demand, the exports from the control area of region/State/Distribution licensee, any energy not served and curtailment, for each hour.

RE Generation constraints: For renewable resources, such as solar and wind, the generation is constrained as per the hourly profile of the resource. Historic profiles of renewable sources shall be used to generate the hourly profiles. Additional constraints to ensure that the distribution licensee's overall renewable generation targets are met, shall also be included.

- **Conventional Generation constraints:**
  - ➢ Unlike solar and wind, thermal resources are dispatchable. However, the thermal resources are bound by constraints such maximum and minimum generation limits, ramp rates, spinning reserve offers, plant availability and unit commitment decisions.
  - ➢ The dispatch (energy offer) plus the reserve offer (specified through regulations) for each generator is constrained to be within the maximum and minimum generation limits. Generation between two consecutive time blocks also must be within the ramping capabilities of the resources. Unit commitment decisions, such as start-up/shut-down, minimum up and down times, etc., require binary variables to implement and are to be included. Additionally, generation units may have periods of outages which may need to be captured by using an availability factor.
  - ➢ The capacity for each year needs to be tracked by a constraint which shall ensure that the capacity in a particular year is equal to the capacity last year plus any new capacity investment minus capacity retirement, if any.

- **RPO constraints:** Fulfilment of Renewable purchase obligation should be considered as one of the objectives of Resource Adequacy. Technology options like renewable generation for round the clock energy supply backed with storage (Battery and PSP), standalone renewable capacity along with hydro capacity for balancing renewable generation may be considered while carrying out resource adequacy exercise for distribution licensees.
- **Storage constraints:** Due to the intermittent nature of renewable generation, the need for resources which can store surplus energy and despatch the stored energy during low RE periods becomes vital. Storage charge and discharge at any instant are constrained by the storage level or the state of charge (SoC) of the storage resource, and the maximum charge / discharge limit. The resource can only discharge if there is sufficient energy present due to prior charging of the resource. To implement this, considering the chronological sequence of time is also important. Since storage resources convert electricity to other forms of energy, there are also some efficiency losses (round-trip efficiency) which shall be accounted for. Different technologies may have different discharge periods (energy limits), power outputs (maximum charge / discharge) and levels of efficiency.
- **Operating (Spinning) Reserve constraints:** Operating reserve constraints ensure that sufficient resources are in the system and kept online or on standby each hour to account for load forecast errors, intermittency of renewables or meeting contingencies in the real time. The thumb rule for operating reserve requirement shall be defined based on discussions with the state SLDC and shall be considered as an input parameter to the model.
- **Demand Response:** Potential for demand side management such as shifting of load or demand response can be considered while undertaking the Resource Adequacy Plan(RAP). The constraints such as periods when load shifting can occur, and the maximum quantum of load which can be shifted over a period shall be included.

ANNEXURE F

Resource Adequacy Implementation Timeline

Entity	Description	May'xx	Jun'xx	Jul'xx	Aug'xx	Sep 'xx	Oct'xx	Nov'xx	Dec'xx	Jan'(xx+1)	Feb'(xx+1)	Mar'(xx+1)	
STU/SLDC	STU/SLDC, on behalf of distrubution licensees shall provide to CEA and NLDC the details regarding demand forecasts for the next 5 years, assessment of exisiting generation resources and other details required for LT-NRAP and ST-NRAP												Delivery Period(Apr'(xx+1) - Mar'(xx+2))
CEA	To publish LT-NRAP containing National PRM, Reliabillity Metrics, Coincident peak, capacity credits and Optimal Generation mix for 10 years horizon.												
NLDC	To publish ST-NRAP.												
Discoms	LT-DRAP exercise for long term horizon(10 years) which is RA compliant as per coincident peak to be submitted to CEA												
CEA	Vetting of discom's contracting plan for coincident peak contribution and to meet their own energy and peak												
SERC	SERC to approve of discom's contracting plan for coincident peak contribution and to meet their own energy and peak												
Discoms	To contract capacities as per approved plans.												
	Submit contract capacities to STU/SLDC												
STU/SLDC	STU/SLDC to submit state-level aggregated capacities to RLDC												
RLDC	RLDC submit regional-level aggregated capacities to national level												
POSOCO/NLDC	POSOCO/NLDS to check RA compliance at national level												
	Any Shortfall shall be communicated to the SERC for comliance or is balanced through a national level auction mechanism												

******