CEA Draft discussion paper on "Methodology for Capacity Credit of Generation Resources & Coincident Peak Requirement of Utilities under Resource Adequacy Framework"

Highlights: According to the guidelines established by the Ministry of Power for the Resource Adequacy planning framework in June 2023, the Central Electricity Authority (CEA) is responsible for publishing capacity credits for various generating resources and outlining each State/UT's contribution to the national peak.

Objective: CEA has produced a draft discussion paper that explores different methodologies for evaluating the capacity credit of solar, wind, and other renewable energy sources. The paper explored various methodologies for estimating the capacity credit of different resources, including **the top 10% demand hours, solar vs. non-solar, and critical day's methods.** Capacity credit estimation is essential for determining the capacity requirements tied up from various resources by state and distribution utilities to meet their coincident peak demand obligations.

Furthermore, it provides utilities with guidance on how to assess their coincident peak needs during the National Peak. The paper suggests that the **solar vs. non-solar methodology** may be a better approach for estimating coincident peaks, especially considering factors such as agricultural load shifting and the focus on adding solar capacity. This method could be more relevant than the traditional **top 5% demand hour** methodology.

The document can be accessed here.

CER Opinion

1. **Methods for Coincidental Peak Calculation:** This discussion papers illustrates (*Refer section 3.0 "Coincident Peak"*) alternate methods to calculate the coincidental peaks. Average of top 5% peak demand presents a risk of under estimation of the expected peak. We can note from the load duration curve of all India electricity demand that top 5% of the time blocks (represent peak demand that has a significant range (Figure 1).

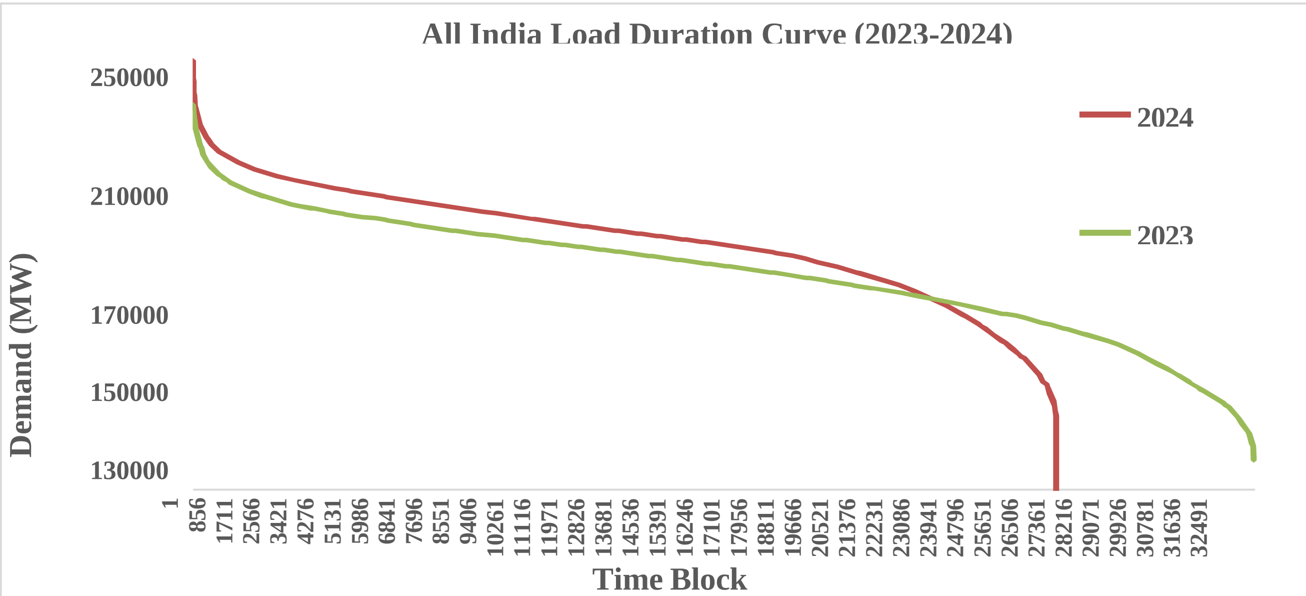

Figure 1: All India Load Duration Curve (2023-24)
Note: 2024 data up to 18th Dec 2024
So: Energy Analytics Lab (EAL), IIT Kanpur

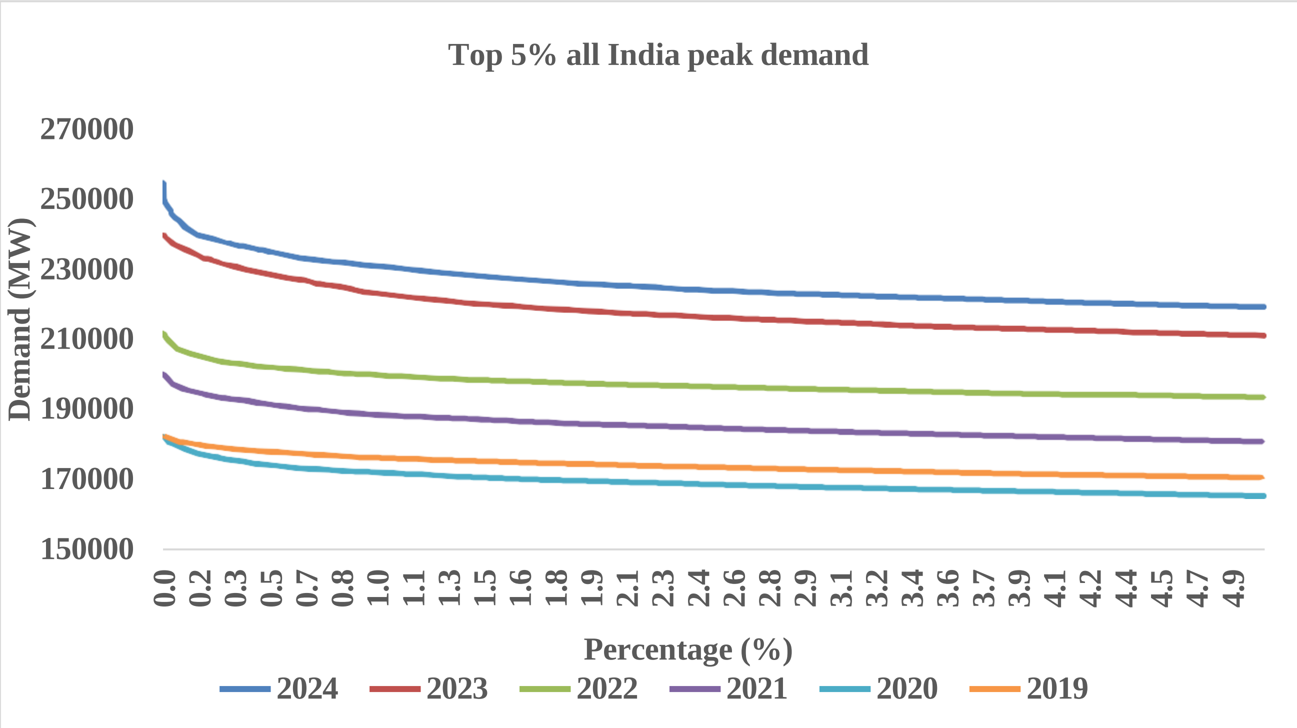

Figure 2: Top 5% all India demand data
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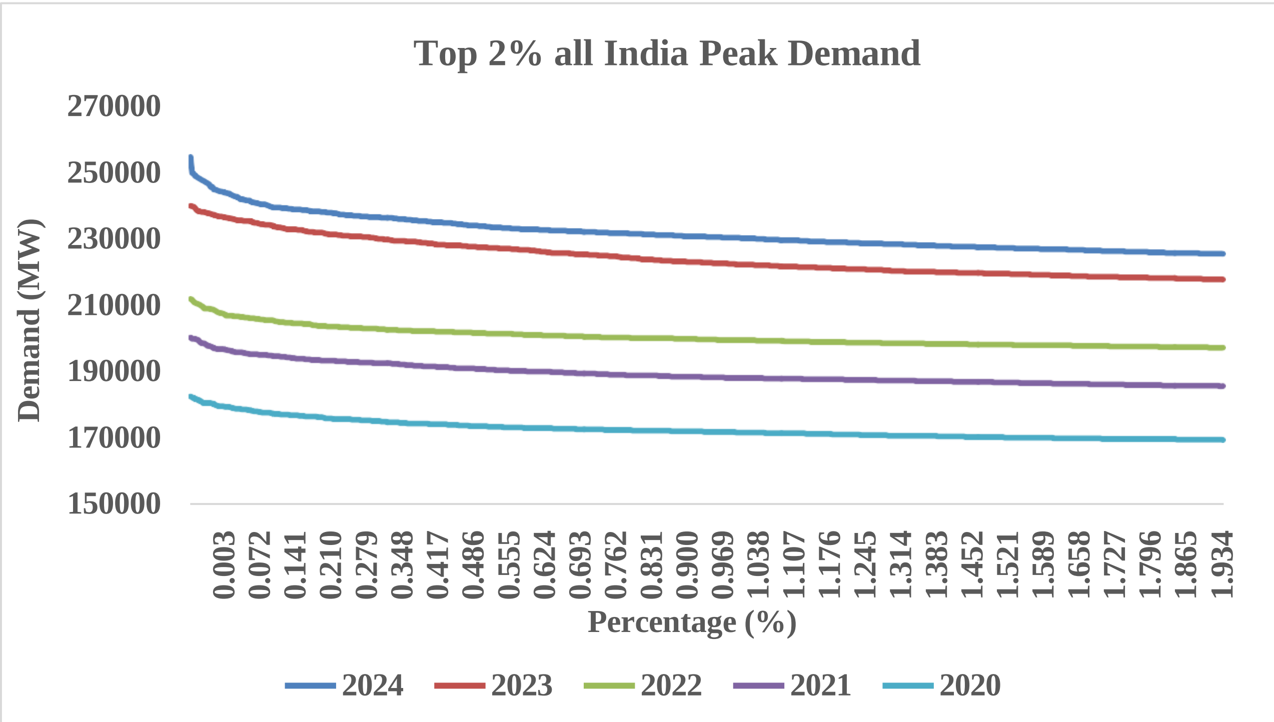

Figure 3: Top 2% all India Load Duration Curve (2020-2024)
So: Energy Analytics Lab (EAL), IIT Kanpur

For example, for part of the 2024 data, this ranges from 219 to 254 GW, with an average of 236.5 GW. Use of the average of top 5% of the demand leaves with an underestimation of about 17.5 GW (14.4 GW in 2023) to the highest peak demand observed. Similar difference across the top 2% hours comes to 14.5 GW (11 GW in 2023). Similar differences are observed across the maximum and the median demand as well. Thus, average as well as median of top 5% or even 2% of the peak demand hours would not adequately represent the peak demand faced in a year.

2. **Choice of Percentiles for Peak Demand Hours:** Planning for the peak national demand with PRM required identification of those high demand hours wherein various states are contributing in different proportions. In Table 1 below, we present analysis of different percentile values of demand and their difference from the observed peak demand across years. It can be observed that selection of 95th percentile of the top 5% of demand hours also does not reflect the actual peak demand observed in the respective years. In fact, the difference has been rising over the years, in general. This highlights the growing peakiness of demand over the years. For the year 2024, the difference between the 110th and the 95th percentile is estimated to be 16.27 GW. The observed peak demand was about 6.8% higher than the 95th percentile rising from 3.36% during the previous year.

Table 1: Percentile (P) Calculation for top 5% Demand (2019-2024)[1]

Top 5% Demand (MW)	2024	2023	2022	2021	2020	2019
80th Percentile (P)	234497	223937.8	200110	188346	172321.3	176125.8
90th Percentile (P)	236829.5	229077.1	202439.6	191296.5	174517.8	177885.6
95th Percentile (P)	238473.5	232029.8	204445.7	193428.7	176422.9	179238.4
100th Percentile (P)	254746	239826	211229	200264.4	178505.9	182640.3
100th (P) – 95th (P)	16272.5	7796.2	6783.3	6835.7	2083	3401.9
100th (P) – 90th (P)	17916.5	10748.9	8789.4	8967.9	3988.1	4754.7
100th (P) – 80th (P)	20249	15888.2	11119	11918.4	6184.6	6514.5

3. Solar Rooftop Installations, and Demand across Solar and Non Solar Hours: As per the defined solar and non-solar hours, load duration curve across the two are significantly differentiated (Figures 4 & 5). Such demand profile may have significant impact on peak demand assessment for some of the states. Uncertainty associated with peak demand during solar hours is expected to grow with increasing penetration of behind the meter solar PV installations, especially post implementation of the PM Surya Ghar Yojna. We suggest two ways to address this – (i) identify solar generation profile from solar rooftop installations, or, (ii) incorporate uncertainty in demand profile during solar hours.

This also highlights the need for greater visibility of generation from solar rooftop installations, data archival and analytics thereof[2]. Smaller installations may be covered on a sampling basis with increasing sampling proportion for larger installations.

[1] The data presented here may not match exactly with that presented in the CEA's discussion paper.

[2] Singh, Anoop (2024), "MNRE (Guidelines for Implementation of PM-Surya Ghar: Muft Bijli Yojana for Component to "CFA to Residential Sector"), 2024 [Draft]", *Regulatory Insights*, Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur, Volume 7, Issue 1, ISSN: 2583-2182 (O). https://cer.iitk.ac.in/periodicals/regulatory_insights/Volume07_Issue01.pdf

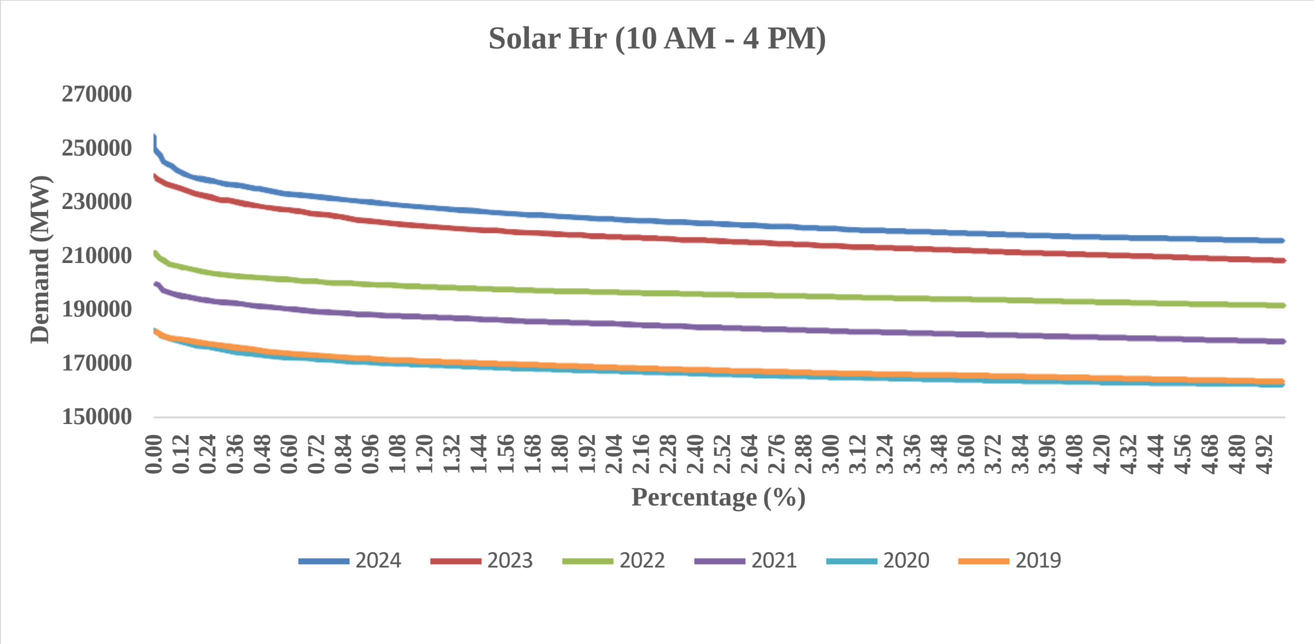

Figure 4: Load Duration Curve (Top 5% of Solar Hours)

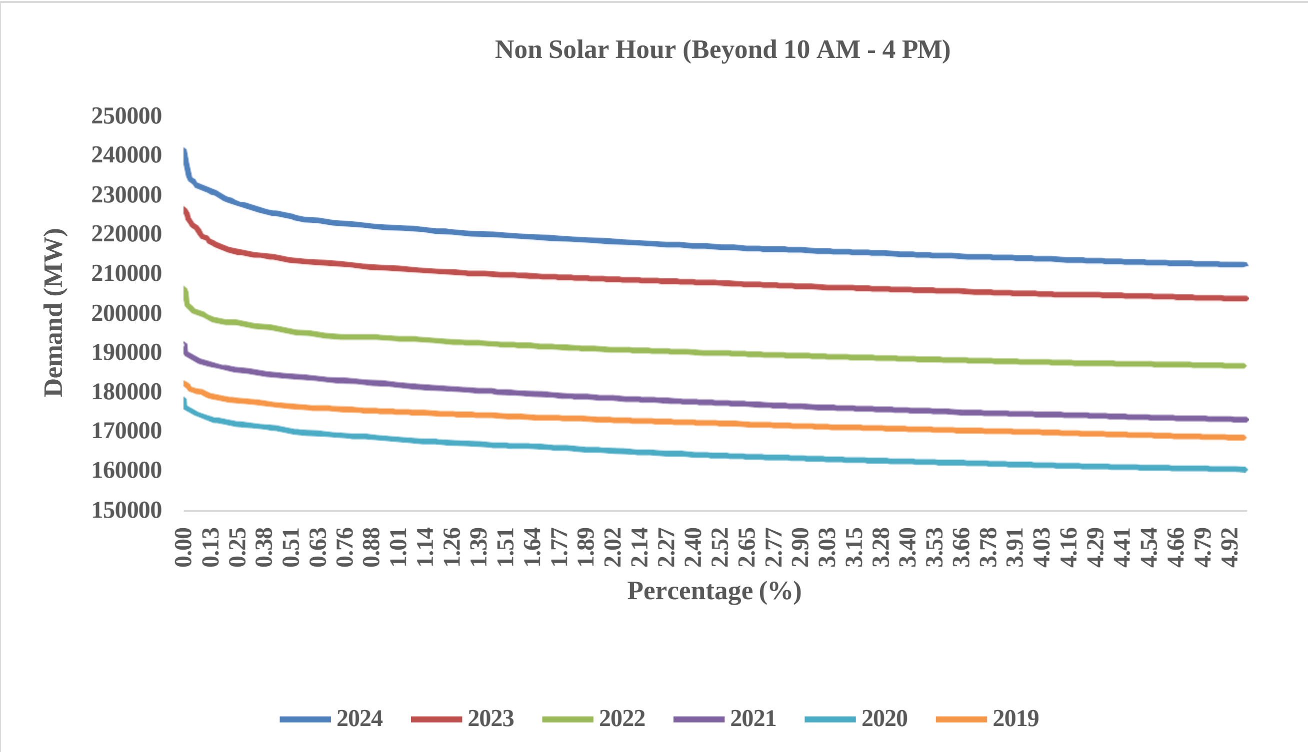

Figure 5: Load Duration Curve (Top 5% of Non-solar Hours)

4. Demand Vs Energy Uncertainty: The guidelines for resource adequacy mandate its planning on hourly basis. Hourly demand can be arrived at either by averaging 15-minute demand data or by using maximum demand observed across the four blocks of an hour. The later method is used by CEA in its methodological approach. Either of the approach leads to uncertainty in undertaking a resource adequacy study. Averaging of demand does not reflect the actual demand observed during the hour.

Use of highest of demand across four blocks of the day would lead to overestimation of demand in energy terms. An attempt to adjust the demand profile to match with the forecasted energy forecast would need downward adjustment of the peak demand. **This dichotomy of uncertainty can be addressed by use of 15-minute block data. In our earlier opinion[3], 15-minute block basis was suggested for undertaking a resource adequacy study.**

5. Regulatory Framework for Power Procurement and Provision under RA Framework: The methodological approach to RA outlines that the discoms should ensure adequacy of resources to meet its contribution to the national peak, during solar as well as non-solar hours. As per RA framework, a discom with a forecasted peak demand during solar hours would also be required to ensure resource adequacy (including PRM) for the coincidental contribution of a discom's demand to the national peak, which may be forecasted to be observed during off-peak hours. This would entail additional cost for the discom. The regulatory framework for power procurement provides for procurement of power to meet discom's requirement. **Would such additional cost be burdened to consumers of such a discoms, and would it be approved by the respective SERC?**

At the same time, the other discoms, whose peak demand coincides with the national peak would also be required to ensure adequacy of resources to meet their own peak demand, and thus would procure power for the same. This will have approval of the respective SERCs. **The overall cost of ensuring resource adequacy may be higher.**

6. National Vs Discom level Planning Reserve Margin (PRM): The approach to estimate national PRM, as per proposed methodologies in the RA Guidelines, needs to ensure that the uncertainties associated with both demand as well as supply side are taken into account. A separate discussion paper may be floated for wider consultation.

Post calculation of Planning Reserve Margin (PRM) at the National level, state level PRM should be estimated considering the non-coincidental nature of the peak demand across discoms (Figure 6). **A uniform PRM of 5% across discoms, in this example, could result in higher PRM at the national level. Aiming to achieve the same would thus result in high cost incidence for the discoms and, hence, the end consumers.**

The non-coincidental nature of peak demand across discoms highlights that to achieve a targeted national PRM, say 5%, the PRM over the forecasted peak demand for the respective discoms need not be as high as 5%.

[3] Singh, Anoop (2023), "CEA (Guidelines for Resource Adequacy Planning Framework for India), 2023", *Power Chronicle*, Energy Analytics Lab (EAL), Indian Institute of Technology Kanpur, Volume 6, Issue 1, ISSN: 2583-2409 (O). https://eal.iitk.ac.in/assets/docs/power_chronicle_vol_6_issue_1.pdf

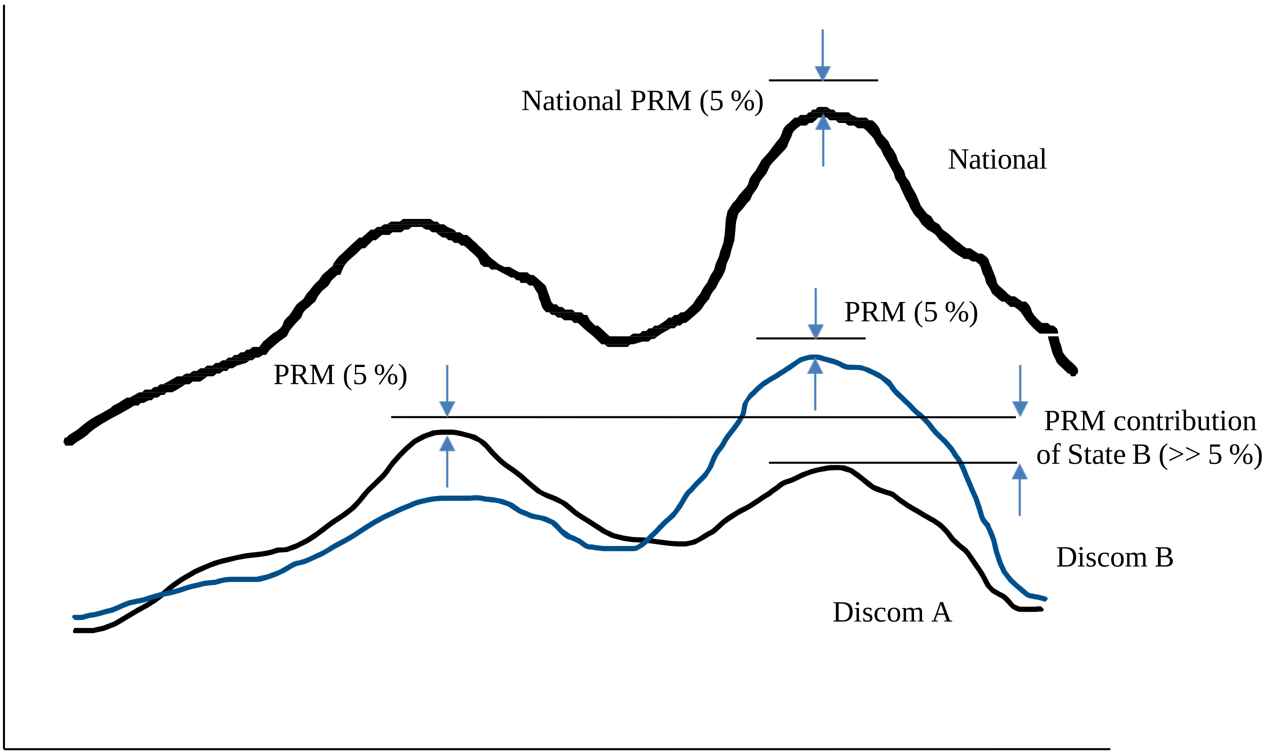

Figure 6: National Vs discom level PRM

With growing procurement of (cheaper) solar power, a number of discoms consider active demand management whereby supply to agricultural consumers is restricted to solar hours, thus lowering its impact on the demand profile. Impact of such active demand management should be built into the future resource adequacy requirement. Similarly, impact of lower tariff during solar hours would also shift some of the household demand to these hours.

Nevertheless, differentiation across solar and non-solar hours should be taken into account while ensuring resource adequacy. For example, a PRM of 5% tied up by State A through solar based resources would not contribute to the PRM during national peak. However, baseload resources during the non-solar hours may be sufficient to ensure 5% PRM contribution to national peak. Further analysis should be undertaken to understand the impact of such an approach.

7. Coincidental Peak of the State or Discom: The methodology to determine the coincident peak demand with top 5% Demand Hour Methodology includes the following steps. (*Refer clause 3.0)*

i. *Collect the demand profile of each state for the last 2-3 years.*
ii. *Based on the demand profile, project the future demand for the next 2 years using the projected peak demand and energy requirement of each state. Combine the individual state profiles to create a national demand profile.*
iii. *Prepare load duration curve (LDC) for the above demand profile.*
iv. *Filter the top 5% of National Peak demand hours.*
v. The average value of the State Demand during the top 5% demand hours is the Coincident Peak Demand of the state for that year to be met by the respective states. (emphasis added)

The proposed methodology refers to demand of the 'State', which may include multiple discoms including those from public as well as private sector. The requirement for resource adequacy lies with respective discoms and hence that should be the unit of analysis and calculations thereof. 'State' may thus be replaced with 'discom'.

8. **Coincidental Peak Demand During Solar and Non-solar hours:** The methodology followed for the calculation of Coincident Peak Demand during Solar and Non- Solar hours, outlines the last step as "Check the summation of Coincident demand for different measures (Maximum, percentiles, average) of all the states/UT with the national Peak demand (Solar and Non-Solar) for that year. **The measure that is <u>closest</u> to the National Peak Demand** should be considered for the determination of the Coincident peak." (emphasis added)

The approach thus suggests to identify 'coincidental' peak of a state (discom) based on the choice amongst the alternate measures i.e. maximum, 90 percentiles or average of the observed demand, amongst the top 5% of the all India peak demand hours, which gives a 'coincidental' demand that sums up closest to the observed national peak in the historical data. This approach artificially picks up 'non-coincidental' demand across the states (within, say, 90 percentiles of top 5% demand hours) so that this adds up to the observed national peak. This approach thus, in fact, uses a sum of such 'non-coincidental' peaks. This sum may even sometimes be higher than the national coincidental peak. An error thus gets introduced due to 'non-coincidental' nature of demand across states. Each state would thus have to use 'non-coincidental' peak demand across solar and non-solar hours to work on its resource adequacy plan. This is not in line with the basic philosophy outlining 'coincidental' natural of demand.

The state (discom)-specific peak demand that would be closest (in fact exactly equal) to the observed coincidental national peak would be the actual coincidental peak observed across states/discoms as per the original data itself. Thus, an alternate approach would be to use top 0.2-0.5% of the top demand hours. This would preserve 'coincidental' nature of state/discom-wise contribution to the national peak demand. A high percentile of data would be chosen in such a manner that the any residual gap, due to departure of the sum of coincidental peak across states from that observed for the national peak, is within the planning reserve margin (PRM)[4].

9. **Capacity Credit for Demand Response:** Calculation of Resource Adequacy Requirement (RAR) should explicitly provide for expected contribution of the Demand Response (DR) measures (Figure 7). **Such contribution of DR should be demonstrated through presence of appropriate quantum of capacity signed up with estimation of actual feasible deployment of DR. The SERCs/JERCs should issue regulations guiding design of appropriate DR program by the distribution licensees/aggregators.** Depending on economic signals, the projected DR would still have some uncertainty associated, and should be

[4] (Sum of coincidental peak across states/discoms – Coincidental national peak) *100 / Coincidental national peak <= PRM

accounted for. Given the associated uncertainty, capacity credit for DR may be prescribed in the range of 0.6 – 0.7.

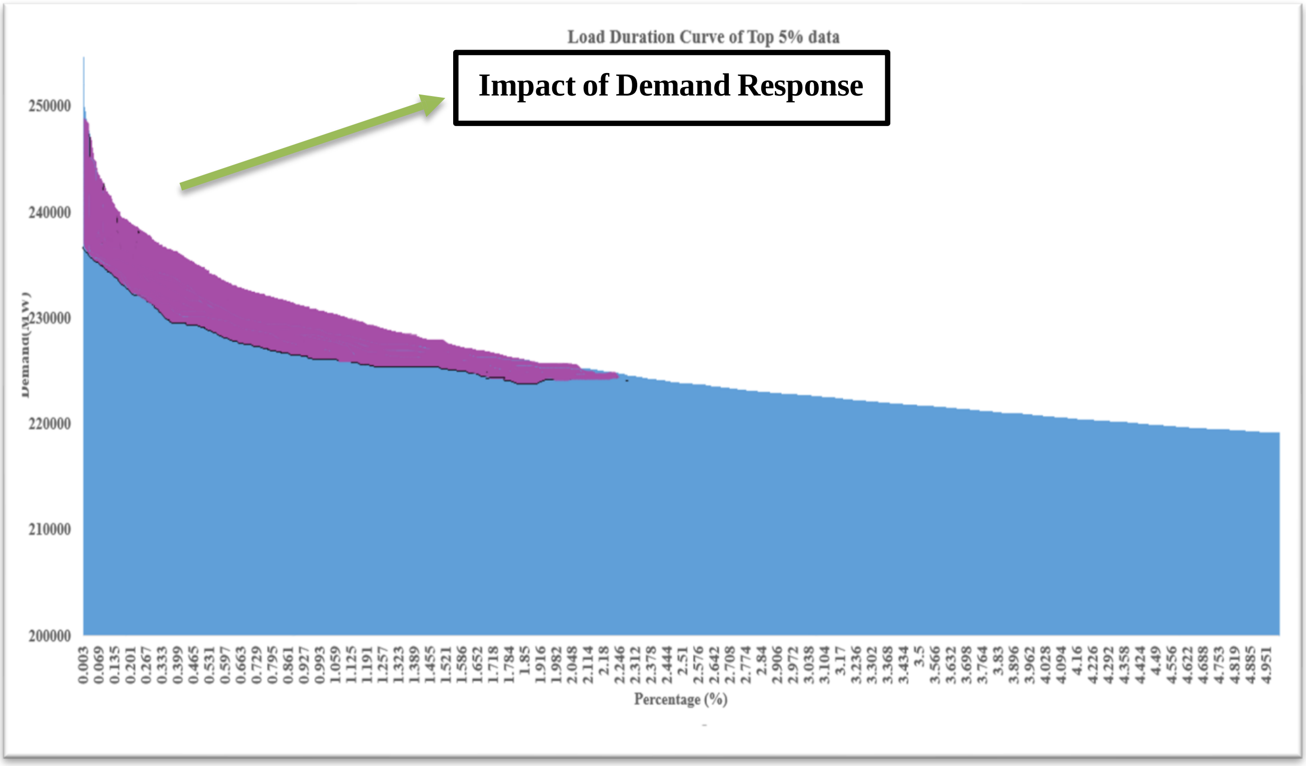

Figure 7: Impact of Demand Response - Load Duration Curve (LDC) of Top 5% Demand Hours

10. Role of Banking and Its Capacity Credit: Distribution licensees, with complimentary of demand profile, resort to banking of power across seasons (Figure 8) as well as hours of the day. **Demonstrated enforceable banking agreements, aimed at meeting the state/discom level peak, for the upcoming year may be considered as a resource available for meeting the RAR.** The philosophy of 'sharing' such capacity is underlined in the non-coincidental nature of the national and the state/discom level peak. A capacity credit of 0.6-0.7 may be considered for such banking arrangements if injection of such power does not coincide with the peak demand hours (solar/non-solar) of the injecting discom, and drawal of power coinciding with the peak demand hours (solar/non-solar) of the drawee discom.

To ensure that the banking arrangements are dependable and enforceable, **model banking guidelines for banking** across discoms may be introduced though consultations at the Forum of Regulators (FoR). These guidelines should ensure minimum 50% of the banked energy deliverable during identified hours across the shared seasons, with incentives (in kind, in energy terms) for delivering more than 50% benchmark during the period identified by the drawee entity. **Based on certainty associated with the banking arrangements to meet the RAR of a discom, adequate capacity credit 0.7-0.8 may be proposed for the same.**

Another innovation would be to introduce **market-based banking arrangements**, which may be cleared through the power exchanges. This would not only ensure enforceability but also bring greater efficiency and competitiveness in banking transactions.

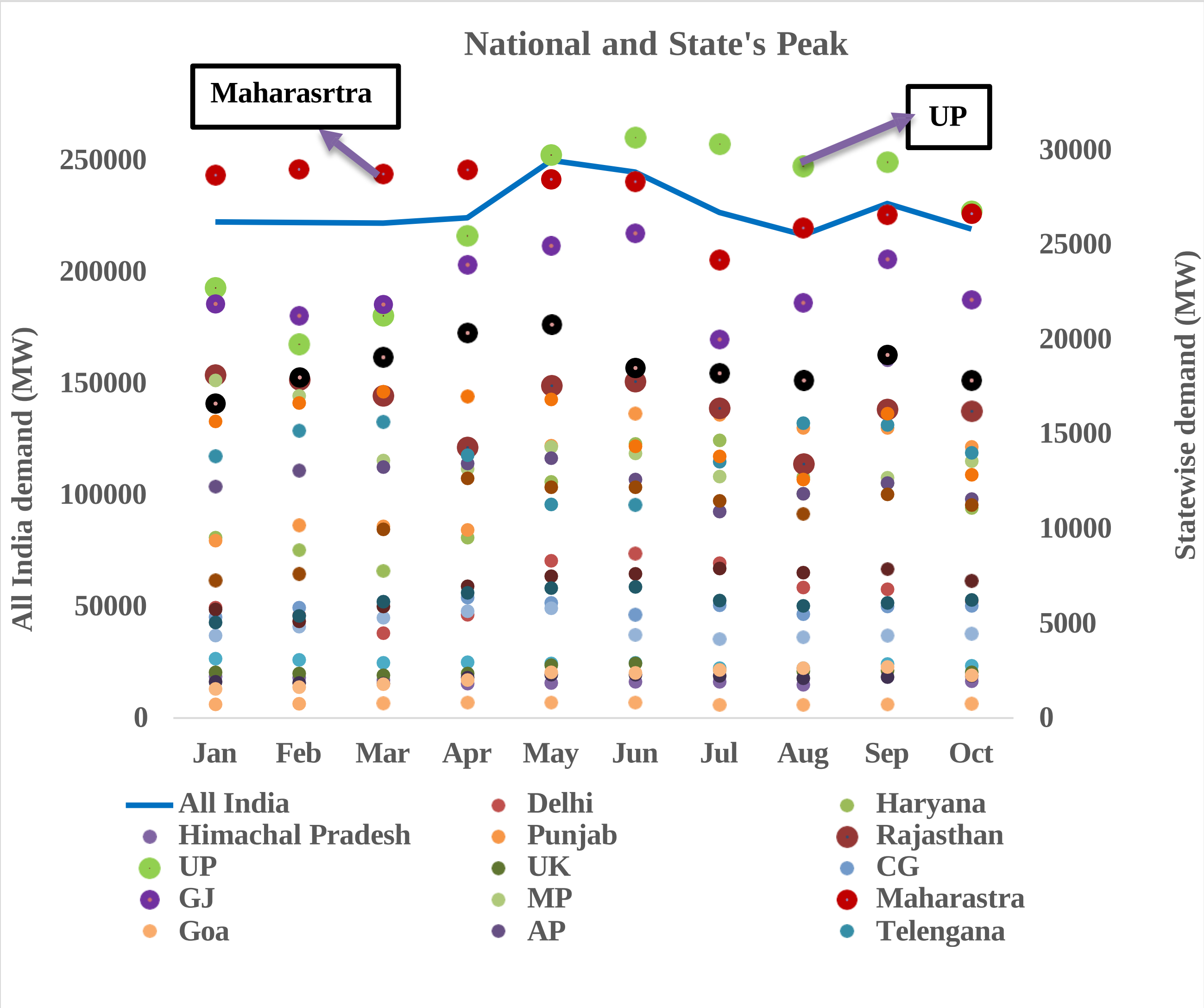

Figure 8: State-wise and All India Peak
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11. Planning for Optimal Power Procurement Vs Planning for RAR: Resource Adequacy framework emphasizes on power procurement tie-ups for meeting state/discoms contribution to the national peak. It does not prescribe optimality of such decision. Discoms should plan for optimal power procurement taking into account techno-economic characteristics as well as availability of various capacities across time-blocks of the day to meet the RAR. The capacity factor and the LCOE of a technology may not be monotonically related. An optimisation model can examine this in a broader context while still adhering to RAR mandate.

12. Capacity Credit (CC) Calculation for the Thermal and Hydro Generators:

"The capacity credit for conventional sources based on the historical generation figures has been estimated in Table 1.

Generation Sources	*Capacity credit (p.u.)*
Coal	*0.7-0.8*
Nuclear	*0.6-0.7*
Gas	*0.7-0.8*
Hydro#	*RoR–0.25-0.3* *With Storage- 0.6-0.7*
Biomass#	*0.3*
PSP@	*0.9-1*
BESS@	*0.5-1*

"

Coal-based thermal power plants continue to provide baseload resources contributing significantly to baseload requirement. Availability of such generating capacity, once adjusted for auxiliary consumption is expected to be available fully during high demand season. Any planned maintenance is, therefore, scheduled during low demand season. Under strained supply conditions, such planned maintenance is sometimes leading to higher probability of forced outages. **With better maintenance scheduling, capacity credit for coal-based generating plant merits to be set at a higher value. CEA may propose a framework for harmonized and optimal maintenance scheduling for generating assets across the country.**

Furthermore, regulated tariff framework for the inter- as well as intra-state generating plants provides for full recovery of capacity charges only is such plants achieve a minimum availability of 85%. Except old plants, where some exceptions are also granted, most of the plants tend to ensure 85% availability on an average across the year. Therefore, **a minimum capacity credit of 0.8-0.85% be considered for coal-based generation plants/contracts.** Further analysis of availability across thermal power plants may be undertaken by the respective discoms/states to set appropriate value of capacity credit for the same.

Capacity credit for gas-based generating plants has significant economic connotations. Based on availability of gas/liquid fuel, this capacity is deployable and may merits higher capacity credit than suggested in the discussion paper. In the case of hydro power, there is significant variation across the years. **For states with peak season coinciding with monsoon season, availability of both RoR as well as those with storage capacity may be set dynamically based on historical performance.** Nevertheless, uncertainty with hydro resources would remain.

13. Variable Capacity Credit across Seasons and across Discoms/States: The vintage of the tied-up generating assets, maintenance schedule and fuel tie-up would influence the capacity credit for the respective capacity. **Thus capacity credits, especially for coal-based capacity, should be differentiated across the plants, and updated from time to time. The CEA may bring forward a framework for assigning such capacity credit for the ensuing planning year.** This would not only ensure that discoms/states have flexibility in approach to set capacity credit based on **Variable capacity credits may be adopted across the seasons, especially those in the context of hydro generation capacity.** Similar approach should be adopted to account for seasonality associated with solar as well as wind resources. A study may be undertaken to develop such a framework with objective criteria for the each of the key factors influencing availability of the capacity.

14. **Capacity Credit for Solar and Non-solar hours:** Differentiated capacity credit needs to be defined for some of the technologies across the solar and the non-solar hours. Storage based hydro resources are particularly deployed during the non-solar peak hours and thus should be earmarked higher capacity credit for such hours. This can be derived on the basis of historical despatch experience across the respective discoms.

15. **Capacity Credit for ESS:** Energy Storage Systems may have capability to supply stored energy during morning/evening peak (or any other time required) based on its capacity to undertake a 1 or 2 cycle operation in a day. Discoms should adopt appropriate capacity credit based on the contractual arrangement for such ESS.

16. **Capacity Credit for Biomass Based Generation:** Biomass availability is seasonal in nature. However, regulated tariff framework across the country provides for up to 4 months of fuel inventory across the year. This should provide for greater availability for such capacity. Based on historical experience, capacity credit may be revised and differentiated across seasons.

17. **Poor Data Visibility:** Subsequent to the issue of latest IEGC 2023, the sector is witnessing a drought for data availability in public domain. For example, scheduling and despatch related data available through WBES is no longer accessible in the public domain. Such data has been and would support numerous independent studies and would further develop research ecosystem. **Urgent steps are required to ensure that such data is made accessible, with some latency, if required.**

18. **RAR for Distribution Licensees: As per Clause 4.1, "*Capacity Credit in Resource Adequacy Framework "The Resource Adequacy Requirement (RAR) constraint ensures that the total Resource Adequacy (Generation capacity) of the distribution licensee fulfills the Planning Reserve Margin as determined by CEA or by the distribution licensee's studies and approved by the SERC/JERC.***
This can be summarized as below.

For LT-NRAP

RAR requirement for ALL INDIA
Total Firm Capacity available = National Peak Demand (ALL INDIA) *(1+ National PRM) Eq (1)

This translates to distribution licenses as
RAR requirement of Distribution licensee

Total Firm Capacity tied up by that Distribution licensee = Contribution to Coincident National Peak*(1+National PRM) Eq (2)*"*

As mentioned above the RAR for the distribution licensee places precedence on the discoms contribution to the national peak, whereas its own peak demand may warrant different strategy for the

RAR for the specific distribution licensee. Furthermore, as also highlighted above, due to non-coincidental nature of peak demand across discoms, discom-wise differentiated PRM (which may be lower than national PRM) would still be able to assure the targeted national level PRM.

The regulatory framework for power procurement across states, thus far, provides for approval of power purchase by a distribution licensee to meet its own (peak) requirement. Tariff policy 2016, should be amended to provide a framework wherein each discom 'contributes' to meet the national peak demand, which may be higher the power procurement, to meet its own peak demand. The issue of additional cost burden, and a mechanism to share the same, would also need to be addressed. In contrast, a discom level power procurement plan. Development of capacity market for 'add on' capacity procurement can help address these issues including 'socialisation' of cost towards procurement of 'incremental' resources to meet the national peak plus the targeted PRM.

19. Capacity Credit of Firm Despatchable RE (FDRE): A number of discoms have entered into long- term contract for FDRE resources. The capacity credit for such a hybrid technology basket with storage is higher and be considered so. Since resource adequacy is with respect to the contracts. Rather than the underlying capacity, firm despatchable capacity from FDRE resources may be assigned a capacity credit of 0.6-0.7. Further analysis, based on the respective contract, may be undertaken to ascertain this across discoms.

20. Economic Viability and Cost Optimisation: *Refer Section 2.1 Mathematical Modelling for Resource Adequacy:* ***"****There is a strong emphasis on using models to optimize the economic viability of energy investments. Models assess the levelized cost of electricity (LCOE) across different technologies, considering capital costs, fuel prices, operating expenses, and financing options to identify the most cost-effective mix of generation resources."*

The Energy Analytics Lab (EAL) at IIT Kanpur has engaged in long-term demand forecasting, and power procurement planning based on long-term optimisation model for the states of Uttar Pradesh and Chhattisgarh. Such analysis minimises to the cost of procurement across the planning horizon, generally 10 years. The **LCOE based approach assesses the respective technology on a stand-alone basis and is not the appropriate methodology for identifying cost effective generation mix. In contrast, the methodological approach for power procurement planning is based on a systems approach considering techno-economic parameters and system constraints thereof.**

21. Capacity Based 'SCED' or Capacity Market for Resource Adequacy Planning: Long-term power procurement planning should provide an economic roadmap for a distribution licensee to meet its RAR. The intermittent phases (months to years) of excess or shortage of capacity is nevertheless going to be witnessed across discoms. Capacity markets can help address this gas in an incremental manner i.e. for add-on capacity requirement or the need to off-load excess capacity. Such marginal optmisation of short-term capacity is akin to optimisation on the margin undertaken in the Security Constrained Economic Despatch (SCED).

22. Role of Captive Generating Sources in the RA: The RAR approach considers only resources tied up by the discoms. The nation has about 128 GW of captive generation capacity (excluding solar and wind) that partly or fully serves the need of such consumers as a source of continuous supply or as emergency backup. Based on their economics, some part of this capacity is available through the power market, including the power exchanges.

The Electricity Act 2003 has adequate provisions to ensure availability of such resources, especially under contingencies leading to shortage of generating resources. Furthermore, such sources can also be requisitioned and deployed by the system operator through ancillary services. A part of such capacity is thus ‘available’ and should be considered towards RAR and/or PRM.

It is suggested that CEA, in consultation with the RLDCs/SLDCs, should capture load profile/grid interaction of such consumers as to improve visibility of such captive capacity. Further analysis may reveal potential for ‘availability’ of such capacity towards RA across the country.