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Report on Resource Adequacy Plan (Generation) for BEST Mumbai (2025-26 to 2035-36)

December, 2025

Government of India
Ministry of Power
Central Electricity Authority

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Disclaimer

This Resource Adequacy study for the Discom of BEST has been conducted based on data and inputs provided by BEST. The findings, analysis and conclusions presented in this report are contingent upon the accuracy, completeness and timeliness of the information furnished by BEST. Any discrepancies or limitations in the data may affect the outcomes of the study accordingly.

In accordance with the Resource Adequacy Guidelines dated 28th June 2023, each Distribution Licensee is mandated to prepare a Resource Adequacy Plan (RAP) for a 10-year horizon, referred to as the Long-Term Distribution Licensee Resource Adequacy Plan (LT-DRAP), which shall be vetted and validated by the Central Electricity Authority (CEA). CEA has facilitated this study and prepared the report solely to assist BEST in fulfilling this requirement.

It is expressly stated that the responsibility for the implementation of the study's recommendations, ensuring the adequacy of electricity resources, and undertaking any related actions including any financial implications etc. rests entirely with BEST.

Executive Summary

Ministry of Power had notified the Electricity (Amendment) Rules in December 2022. As per Rule 16 of the Electricity (Amendment) Rules, the Ministry of Power has notified the Resource Adequacy (RA) Guidelines. According to these Guidelines, the Central Electricity Authority (CEA) is entrusted with the responsibility of preparing the Long-Term National Resource Adequacy Plan (LT-NRAP). Further, each Distribution Utility is required to carry out a Long-Term Distribution Licensee Resource Adequacy Plan (LT-DRAP) to reliably meet its peak and energy requirements.

As per the Resource Adequacy Guidelines dated 28th June 2023, each Distribution Licensee shall undertake a Resource Adequacy Plan (RAP) with a 10-year planning horizon, LT-DRAP to meet its own peak electricity demand and electrical energy requirement. This plan shall be vetted/validated by CEA to leverage the benefits of national-level optimization for the Distribution Licensees. The LT-DRAP shall be prepared by the Distribution Licensees on an annual rolling basis, factoring in the already contracted capacity and optimizing the requirement for additional capacity.

The Government of India has also recently notified the Renewable Purchase Obligation (RPO) trajectory up to 2029-30, vide Gazette Notification dated 27th September,2025, which mandates that a specified portion of energy consumption must be met from renewable energy sources.

To support the utility in fulfilling this requirement, CEA, in collaboration with the State/DISCOM, initially conducted a Resource Adequacy (RA) study with a planning horizon up to FY 2034-35, based on the data received from the BEST and in compliance with the RPO trajectory specified in the Ministry of Power's gazette notification dated 27th September,2025. This study has now been updated and extended to cover the period up to FY 2035-36, incorporating the latest data furnished by the DISCOM and planning assumptions. The RPO requirement for the utility has also been assessed in accordance with the recent gazette-notified trajectory.

The electrical energy requirement and peak electricity demand for BEST are increasing with a CAGR of 1.4 % and 0.8 % respectively, from 2025-26 to 2035-36 as forecasted by BEST Discom. For satisfying resource adequacy, i.e. meeting the electricity demand reliably and at an affordable cost, the DISCOM needs to methodically plan its capacity expansion either by investing or by procuring power. In view of the reduction in the cost of solar panels and newer technology options, such as storage systems, planning for a long-term optimal generation capacity mix gains tremendous importance, ensuring that the future generation capacity mix is both cost-effective and environmentally friendly.

A study has been carried out for BEST considering the existing contract capacity and planned capacity addition. It was found that the DISCOM's likely contracted capacity may not be sufficient to meet the projected demand. Further, the total unserved energy in the year 2035-36 is expected to be about 748 MU, which is about 12% of the annual projected electrical energy requirement during the year 2035-36.

To find out the least cost option for generation capacity expansion for the period 2025-26 to 2035-36, a long-term study has been carried out with the objective to minimize the total system cost of generation, including the cost of anticipated future investments, while fulfilling all the technical constraints associated with various power generation technologies. Additionally, reliability study has been carried out to determine the probability of unmet demand and hours by implementing the variation in demand, RE and forced outage of thermal generators (Coal/ Lignite) etc.

Generation capacity expansion pathways have been considered for the long-term study based on the yearly capacity addition plan of BEST along with RPO constraints for solar and wind technologies. The Renewable capacities have been assessed in view of adherence to RPO notified by Ministry of Power considering the fungibility among different sources.

Resource adequacy studies have projected a likely optimal capacity mix for future years till 2035-36, which can meet anticipated demand reliably at every instance. Based on the study, the likely total projected contracted capacity requirement for the year 2035-36 is around 2430 MW which consists of 456 MW from coal, 92 MW from gas, 152 MW from hydro, 343 MW from Wind, 791 MW from solar, 224 MW from Distributed Renewable Energy (DRE), 77 MW of PSP (6 hours), 180 MW of BESS (4 hours) and 115 MW of STOA. This capacity shall be able to meet the projected demand with prescribed reliability criteria.

1.0 Introduction

Ministry of Power has notified Electricity (Amendment) Rules, 2022, in December 2022. Rule 16 (I) of the said rules stipulates that "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". Accordingly, the Resource Adequacy Guidelines have been notified in June, 2023 by Ministry of Power in consultation with Central Electricity Authority.

Resource Adequacy is generally defined as a mechanism to ensure that there is an adequate supply of generation resources to serve expected demand reliably at least cost. 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 naturally translates into the need for ensuring adequate reserve margin, which could cater to varying levels of demand and supply conditions in the grid. In the wake of high RE generation, it is important to understand demand-supply situation in the grid precisely due to high seasonality and intermittency in RE generation. Resource Adequacy exercise may also help in assessment of capacity requirement to be tied up or contracted on long term, medium term, and short-term basis.

Further, Ministry of Power vide notification dated 27th September 2025, had notified the RPO trajectory for the states/Discoms. Based on the trajectory specified, hydro, wind and other (solar, biomass etc.) RPO quantum in million units (MUs) has been calculated to find additional quantum of renewable capacity that the states/Discoms have to contract in addition to its existing/planned capacity to meet their RPO targets.

To support the utility in fulfilling the Resource Adequacy Guidelines and complying with the Renewable Purchase Obligation (RPO) notification, CEA has carried out the RA study for the Discom of BEST based on inputs furnished by BEST. The study recommends an optimal resource mix up to FY 2035-36, taking into account technical and financial parameters associated with various capacities. It aims to optimize long-term power procurement while ensuring resource adequacy to meet demand on a 24×7 basis, considering variations in demand, RE generation, and forced outage of thermal capacities. The study assesses the Planning Reserve Margin (PRM) required by the state/DISCOMS to account for the aforementioned uncertainties, ensuring that demand can be reliably met throughout the year.

Prior to this, CEA conducted the RA study for the DISCOM up to FY 2034-35, based on inputs from BEST and in accordance with the prevailing RPO trajectory specified in the Ministry of Power's Gazette notification dated 20th October, 2023.

2.0 Highlights of the Previous RA Study (Up to FY 2034-35)

1. In the earlier Resource Adequacy (RA) study, the financial year 2023-24 had been considered as the base year, and the study covered the period from 2024-25 to 2034-35. The fuel-wise contracted capacity by BEST as on March, 2024, is given in Figure 1.

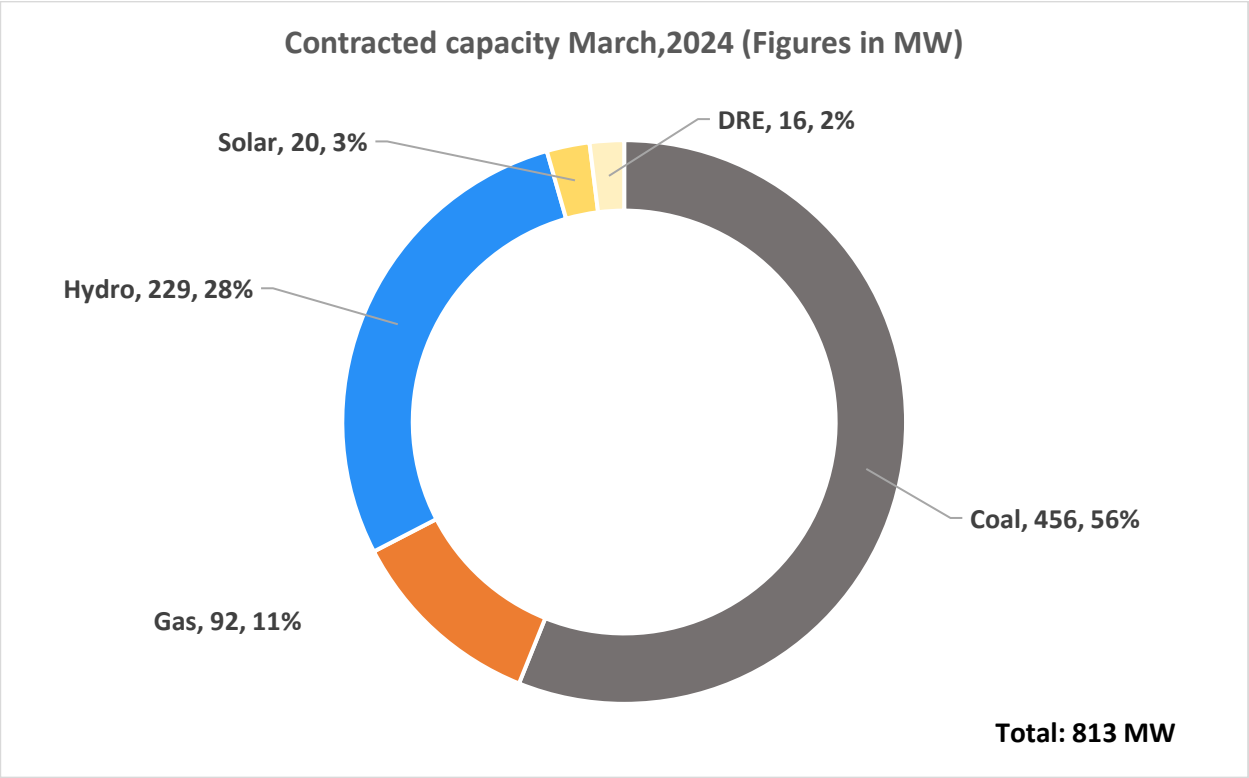


Figure 1: Contract Capacity (March 2024)

2. The hourly electricity demand pattern for 2023-24 was analysed and had been considered as a base profile to interpolate the electricity demand for future years.
3. The peak electricity demand and electrical energy projections as per BEST had been considered in the study is given in Table 1.

Table 1: Peak electricity demand and Electrical Energy Requirement Projections as per BEST

	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Energy Projections (MU)	5186	5284	5384	5486	5590	5696	5804	5914	6026	6140	6257
Year on Year Growth (%)		1.9%	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%
Peak Demand Projections (MW)	991	1004	1017	1031	1044	1058	1072	1086	1100	1115	1130
Year on Year Growth (%)		1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%

4. The actual peak electricity demand and electrical energy requirement of the BEST during 2023-24 and 2024-25 as per the Demand Profile provided by BEST is given in Table 2.

Table 2: Actual Peak Electricity Demand and Electrical Energy requirement

Year	Actual Electrical Energy Requirement (in MU)	Actual Peak Electricity Demand (in MW)
2023-24	5099	977
2024-25	5241	1003

To meet the above projected peak electricity demand and electrical energy requirement reliably, the source-wise projected capacity (in MW) as outlined in the previous report is given in Table 3.

Table 3: Projected contracted capacity (in MW)

Year	Coal	Gas	Hydro	Wind	Solar	DRE	Total	Storage (4 Hours)	STOA
2024-25	456	92	229	0	20	63	**860**	0	406
2025-26	456	92	229	103	551	90	**1521**	0	231
2026-27	456	92	229	103	551	119	**1550**	0	236
2027-28	456	92	229	103	551	148	**1579**	0	241
2028-29	456	92	229	123	571	178	**1649**	36	199
2029-30	486	92	229	143	591	209	**1750**	76	131
2030-31	516	92	229	173	621	237	**1868**	110	66
2031-32	546	92	229	203	651	265	**1986**	110	50
2032-33	576	92	229	233	681	295	**2106**	110	37
2033-34	606	92	229	263	711	325	**2226**	136	15
2034-35	636	92	229	293	737	357	**2344**	176	0

5. The year-wise planned and additional capacity contract (in MW) for the above tabulated cumulative capacity is given in Table 4.

Table 4: Year wise planned and additional capacity (in MW)

FY	Coal	SOLAR		Wind		DRE		Total		Storage (4 HOURS)	STOA
	Additional	Planned	Additional	Planned	Additional	Planned	Additional	Planned	Additional	Additional	Additional
2024-25	0	0	0	0	0	2	45	**2**	**45**	0	406
2025-26	0	531	0	103	0	2	25	**636**	**25**	0	231
2026-27	0	0	0	0	0	2	27	**2**	**27**	0	236
2027-28	0	0	0	0	0	2	27	**2**	**27**	0	241
2028-29	0	0	20	0	20	2	28	**2**	**68**	36	199
2029-30	30	0	20	0	20	2	29	**2**	**99**	40	131
2030-31	30	0	30	0	30	2	26	**2**	**116**	33	66

FY	Coal	SOLAR		Wind		DRE		Total		Storage (4 HOURS)	STOA
	Additional	Planned	Additional	Planned	Additional	Planned	Additional	Planned	Additional	Additional	Additional
2031-32	30	0	30	0	30	2	26	**2**	**116**	0	50
2032-33	30	0	30	0	30	2	28	**2**	**118**	0	37
2033-34	30	0	30	0	30	2	28	**2**	**118**	27	15
2034-35	30	0	26	0	30	2	30	**2**	**116**	40	0
Total	**180**	**531**	**186**	**103**	**190**	**22**	**319**	**656**	**875**	**176**	

3.0 RA Study for BEST (from 2025-26 to 2035-36)

3.1 Present Power Scenario in BEST

Peak and Energy demand for BEST for 2023-24 to 2024-25 is given in Table 5.

Table 5: Peak and Energy Demand

Year	Actual Electrical Energy Requirement (in MU)	Actual Peak Electricity Demand (in MW)
2023-24	5099	977
2024-25	5241	1003

As of March 2025, the total contracted capacity for BEST is 815 MW. Out of the total contracted capacity (CC), the share of non-fossil fuel-based Contracted Capacity is 33%.

The fuel-wise contracted capacity as on March, 2025 is given in Table 6 and Figure 2.

Table 6: Fuel-wise Contracted Capacity as on March 2025

Source	Contracted Capacity (MW)	Percentage (%)
Coal	456	56%
Gas	92	11.3%
Hydro	229	28%
Solar	20	2.5%
DRE	18	2.2%
Total	**815**	**100%**

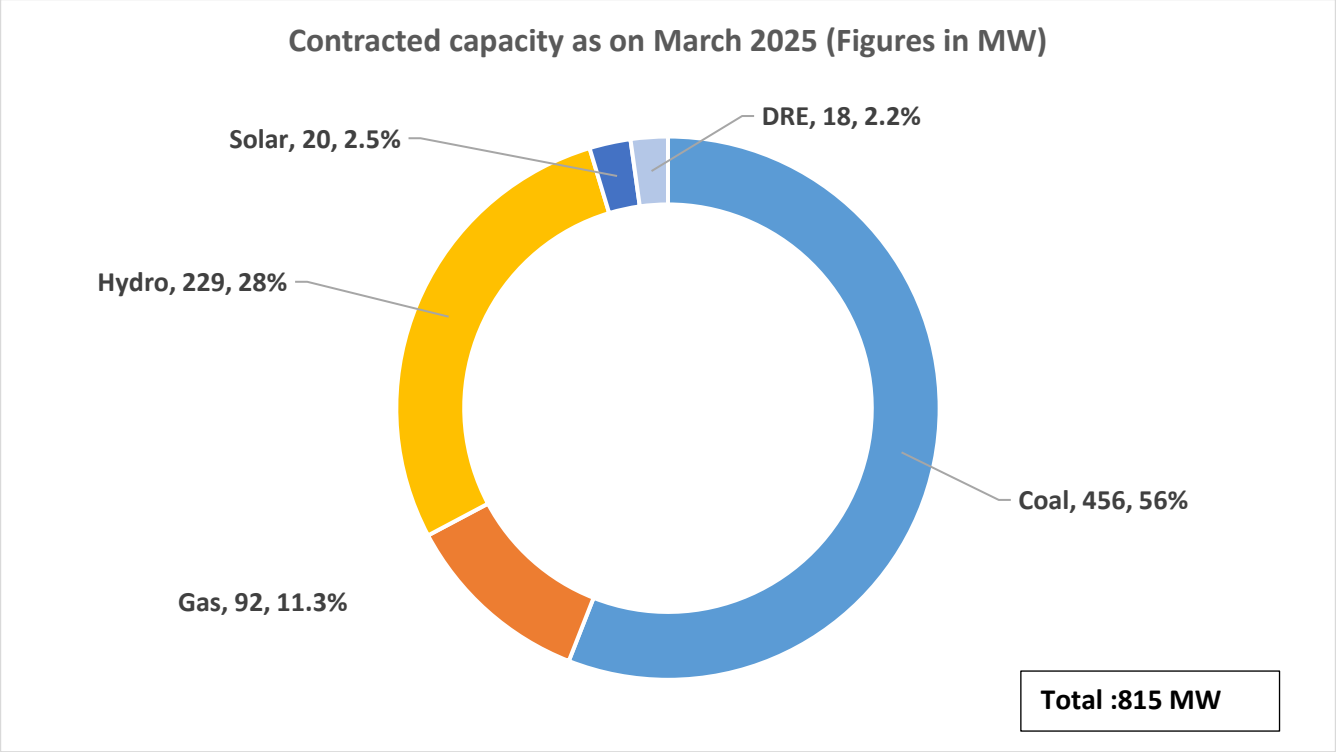


Figure 2: Fuel-wise Contracted Capacity (in MW) as on March, 2025

3.2 Electricity Demand Analysis of the FY 2024-25

The hourly electricity demand pattern of 2024-25 was analyzed, and it was observed that peak electricity demand in BEST occurs during solar hours in the month of May, 2024.

The month-wise variation in average hourly electricity demand observed for the year 2024-25 is shown in Figure 3.

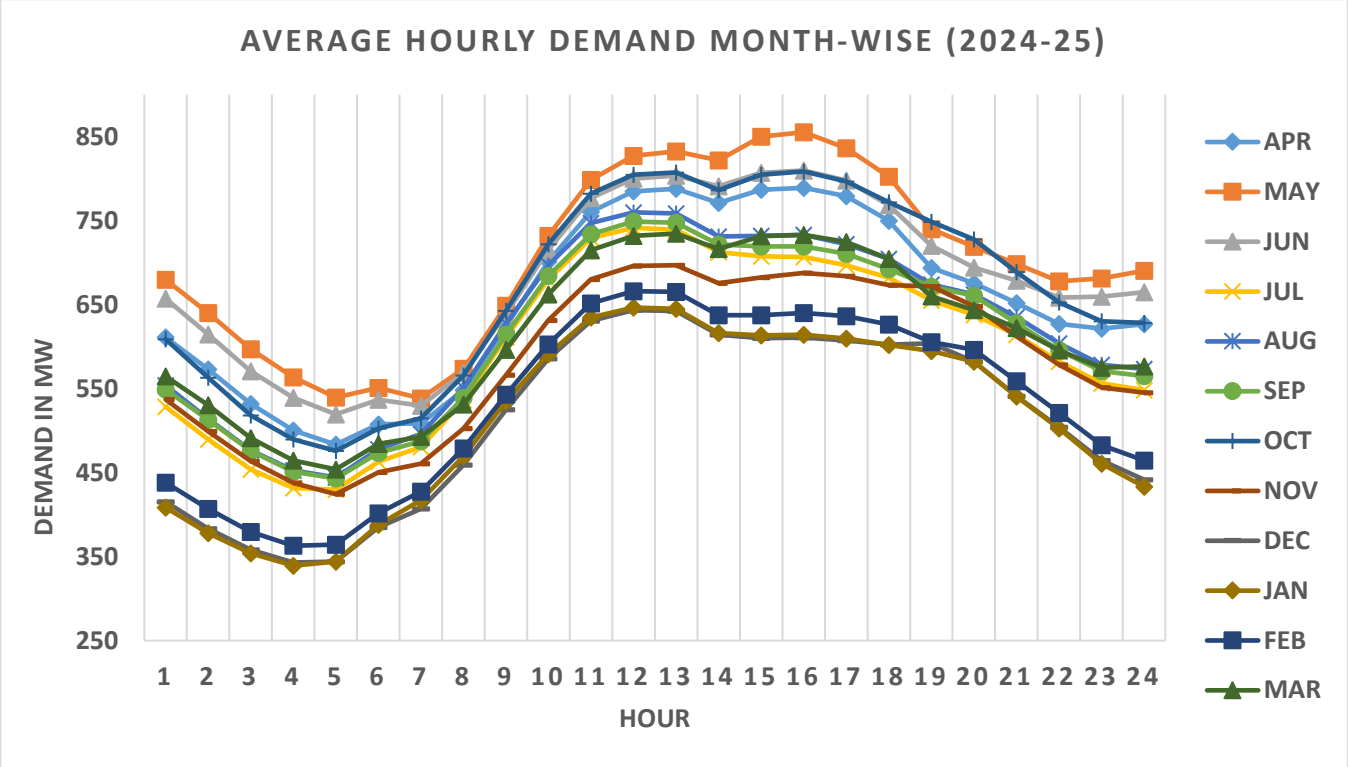


Figure 3: Average Hourly Demand Variation (Month-wise) for 2024-25

From the hourly demand data of 2024-25 the daily peak during solar hours (06:00 to 18:00 hrs) and non-solar hours are plotted in Figure 4.

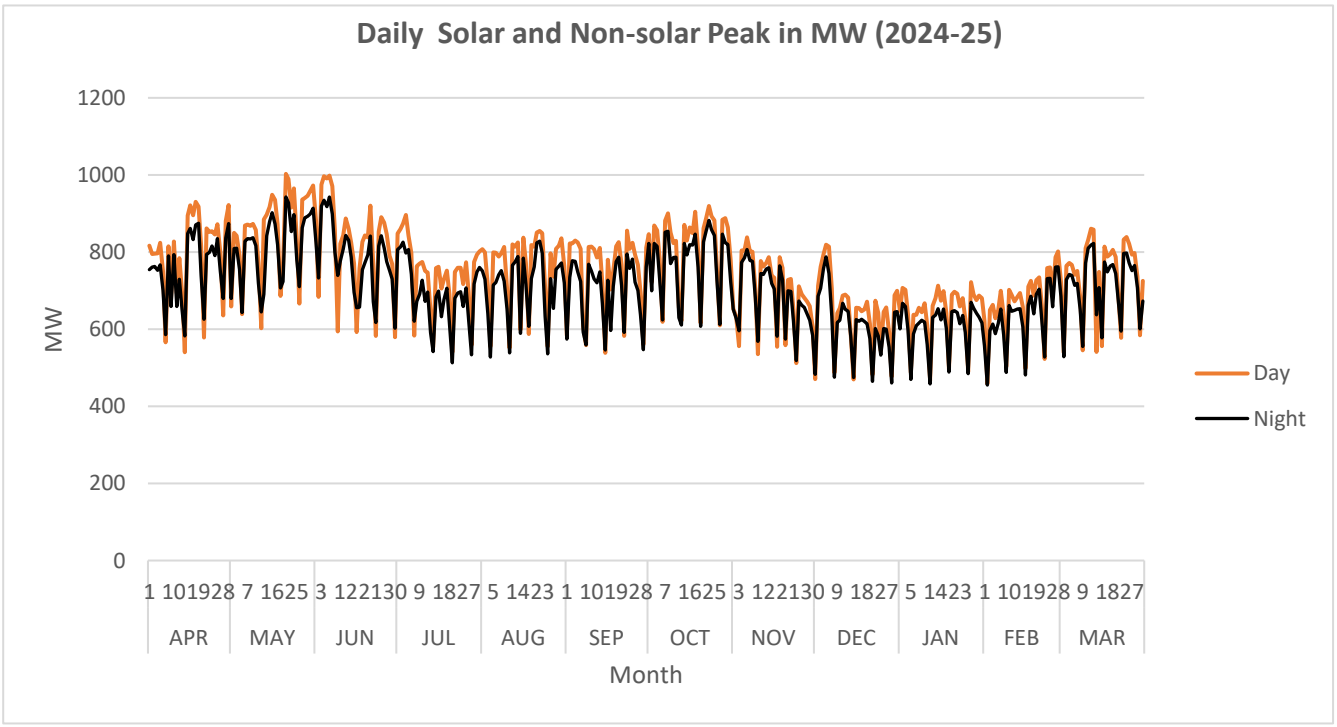


Figure 4: Solar and non-solar Peak in MW for the year 2024-25

As seen in Figure 4, the daily peak demand occurs during solar hours throughout the year.

The hourly demand pattern of 2024-25 was analysed for finding out the number of occurrences of the peak and near peak demand. Such instances are critical for study purpose as it is necessary to ensure resource adequacy during such instances with an optimal mix of long-term, medium-term and short-term contracts.

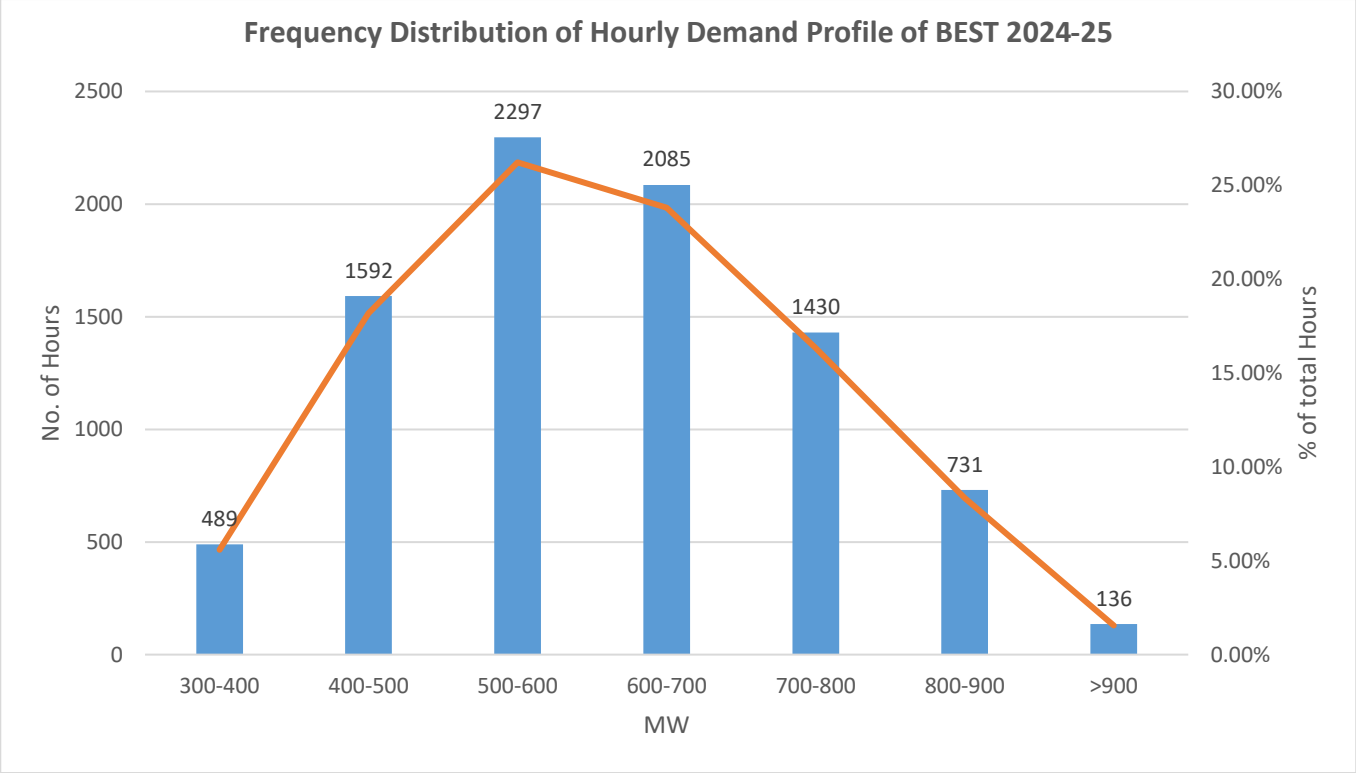


Figure 5: Frequency Distribution of Hourly Demand Profile of 2024-25

4.0 Principles of Generation Planning

The objective of the Generation Planning process is to obtain an optimal generation capacity mix in the least cost manner to meet the demand at every instance of time while ensuring the most efficient use of resources. Planning is therefore an activity encompassing balancing demand and supply at all instances of time and at all locations, which makes it a regular ongoing process.

The major aspects considered in the planning process are:

i) To Supply 24x7 reliable power to consumers
ii) To achieve objectives of all policies of the Government of India such as RPO trajectory, RE capacity addition etc.
iii) To achieve sustainable development.
iv) To fulfil desired operational characteristics of the system such as reliability and flexibility.
v) Most efficient use of resources.
vi) Fuel availability

4.1 Generation Expansion Planning Tool -ORDENA

The studies were carried out using a generation expansion planning model namely ORDENA. ORDENA is a mixed integer linear optimization program that minimizes the Net Present Value (NPV) of investment and operating costs subject to several constraints. The major constraints include balancing electricity supply and demand, resource supply limits, planning and operating reserve limits, and policy targets. These constraints are met considering a broad portfolio of conventional generation, renewable generation, and storage.

ORDENA has a reliability module to determine the trustworthiness of the system using Monte Carlo simulations. The software is also capable of carrying out hourly/sub-hourly economic generation dispatch, considering all the technical constraints associated with various generation technologies.

The schematic diagram of the software is given in Exhibit.

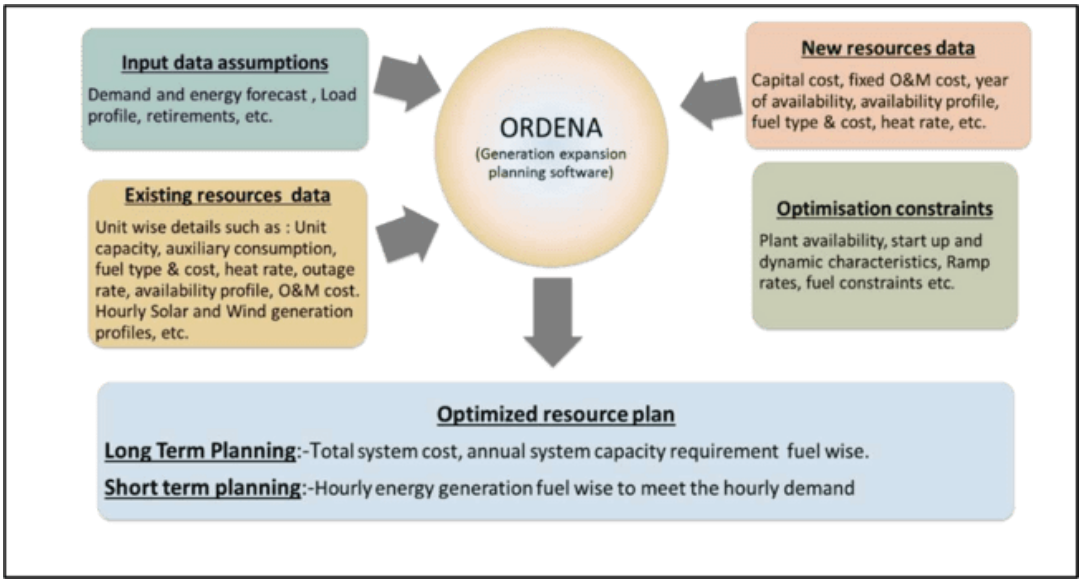


Exhibit: Schematic Diagram-ORDENA

5.0 Reliability Analysis

One of the main criteria of resource adequacy studies is to determine the reliability of the system to meet the demand adequately at every instant of time. This reliability is measured via two indices (i.e.) LOLP (Loss of Load Probability) and EENS (Expected Energy Not Served). These indices have been defined in resource adequacy guidelines as below:

- **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.
- **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 Mega Watt hours (MWh). The metric can be normalized (i.e., divided by total system energy requirement load in MWh) to create a Normalized Energy Not Served (NENS) metric.

Monte Carlo /Stochastic simulation has been used to factor-in the uncertainty associated with various generation resources and demand. It is an approach which is used to predict the probability of a variety of outcomes when the potential for random variables is present, as compared to deterministic modelling of economic dispatch model. Monte Carlo simulation helps in analysing the randomness associated with RE energy resource, demand pattern changes and forced outages of plant. A large number of random samples of these variables are simultaneously simulated to ascertain system reliability indices (i.e. Loss of load probability LOLP & Energy Not Served (ENS)) & the system robustness in case of above variation of system parameters.

Planning Reserve Margin (PRM): 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 percent of projected peak load of the system.

5.1 Electricity Demand variation

The variation in electricity demand pattern for the past two years has been analyzed. The hourly electricity demand variation for consecutive years (i.e., 2023-24 and 2024-25 considering 2023-24 as base) has been analyzed. The electricity Demand pattern variation of 2023-24 and 2024-25 is shown below.

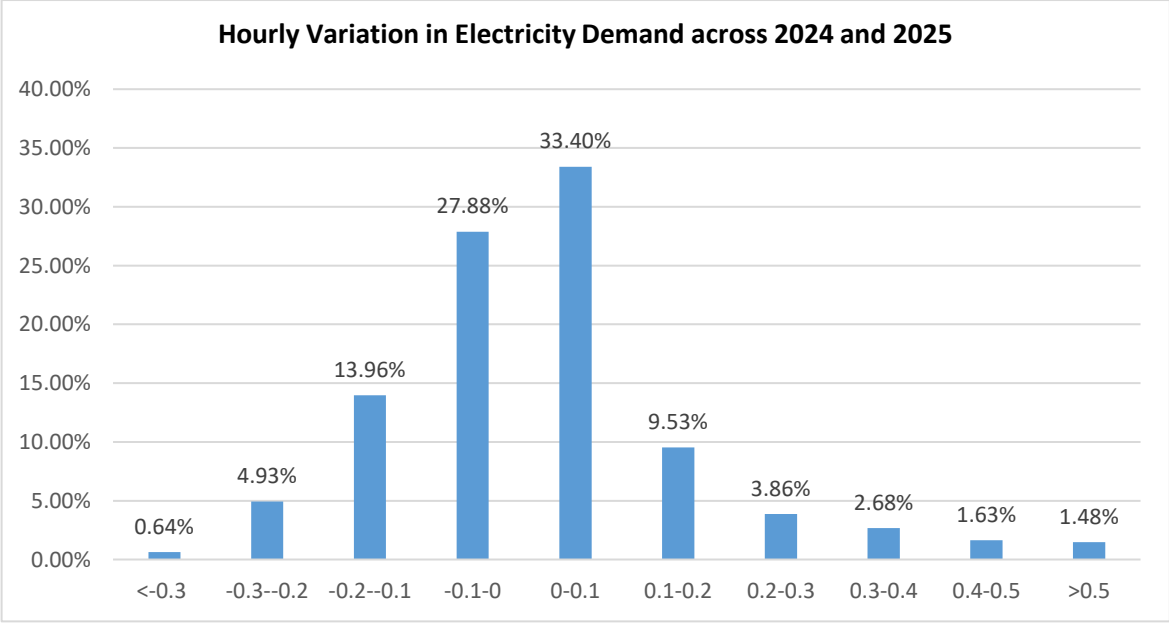


Figure 6: Hourly Variation in Electricity Demand across years

It can be observed that the hourly electricity demand typically varies ±10% for 61.28% of instances. This variation is primarily due to temperature, weather parameter or any random outages of transmission line and generating units etc. This variation has been captured in the reliability study by varying the projected hourly demand for the future years by varying ±10% by introducing a random variable (with normal distribution) for demand as per observed behavior over the years.

5.2 Variation in RE

In the long-term capacity expansion planning studies, a particular profile for Solar, wind and hydro has been considered based on the observed solar generation data to determine the optimal capacity mix. However, due to intermittent nature of these sources, the generation from these non-dispatchable sources may vary across years. As per the analyses carried out based on historical generation data, solar and hydro based generation has been varied by ± 10 % and wind generation has been varied by ± 50% to incorporate the variation in these generation sources and plan for requisite measures to mitigate such behavior.

5.3 Forced Outage of Thermal Generators

The average forced outage rate of thermal generators is typically 10% with ±5% variation. The same has been incorporated in the model.

Based on these variations reliability studies have been carried out to ascertain robustness of the system.

6.0 Inputs/Assumptions for the Study

i) The electrical energy requirement of BEST, furnished by Discom and projections available in the 20th EPS (Electric Power Survey) are tabulated below. The utility's electrical energy requirement more than 20th EPS (Electric Power Survey) and Peak electricity demand observed in 2024-25 was closer to BEST projected Peak electricity demand.

Table 7: Future Electricity Demand Projection as provided by BEST and as per of 20th EPS Report

Year	Projections by BEST				Projections as per 20th EPS			
	Peak Electricity Demand		Electrical Energy Requirement		Peak Electricity Demand		Electrical Energy Requirement	
	Projections (MW)	Y-o-Y Growth	Projections (MWh)	Y-o-Y Growth	Projections (MW)	Y-o-Y Growth	Projections (MWh)	Y-o-Y Growth
2025-26	1012		5302		996		5233	
2026-27	1021	0.84%	5377	1.41%	1011	1.51%	5301	1.30%
2027-28	1029	0.84%	5454	1.43%	1026	1.48%	5370	1.30%
2028-29	1038	0.84%	5532	1.43%	1042	1.56%	5444	1.38%
2029-30	1047	0.84%	5611	1.44%	1061	1.82%	5532	1.62%
2030-31	1056	0.84%	5692	1.44%	1085	2.26%	5638	1.92%
2031-32	1064	0.84%	5775	1.44%	1104	1.75%	5724	1.53%
2032-33	1073	0.84%	5858	1.45%	1123	1.73%	5810	1.51%

2033-34	1082	0.84%	5943	1.45%	1143	1.73%	5898	1.51%
2034-35	1091	0.84%	6030	1.46%	1162	1.73%	5987	1.51%
2035-36	1101	0.84%	6118	1.46%	1182	1.73%	6077	1.51%

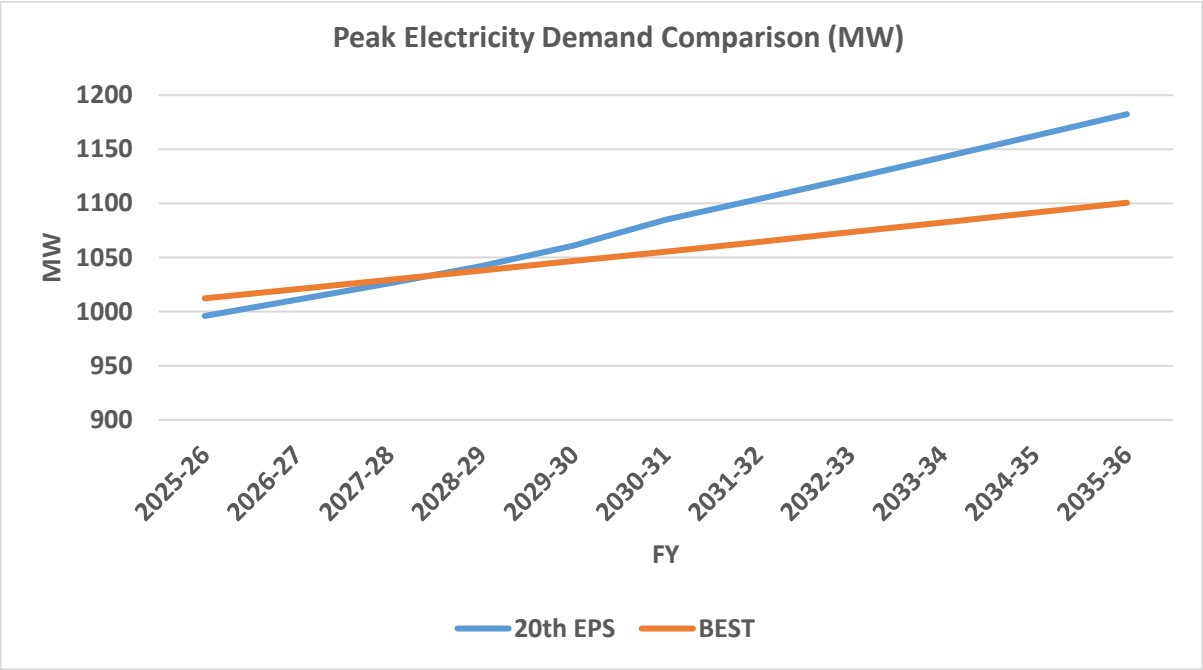


Figure 7: Comparison of Peak Electricity Demand Projections of 20th EPS vs BEST

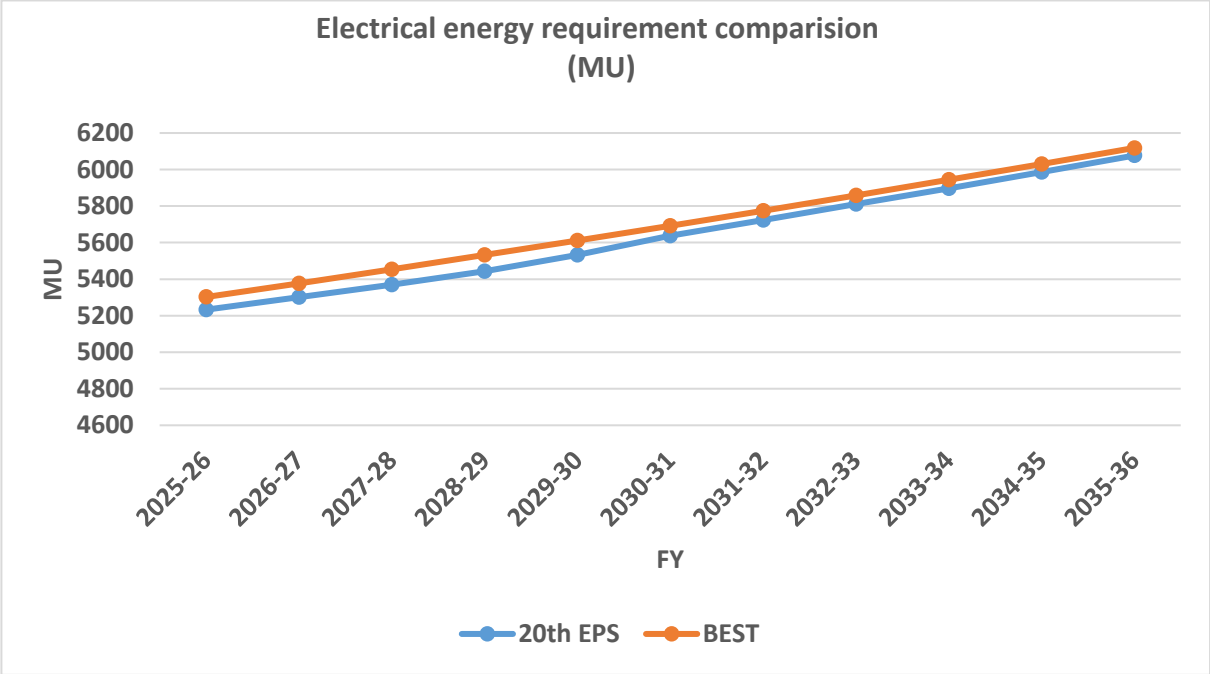


Figure 8: Comparison of Electrical Energy Requirement Projections of 20th EPS vs BEST

The electrical energy requirement of BEST is more than that of 20th EPS (Electric Power Survey) and Peak demand observed in 2024-25 is closer to BEST projected Peak demand. Therefore, the peak demand and energy requirement projections from BEST have been considered.

ii) Future electricity demand profile till the year 2035-36 has been projected using the electricity demand profile for the year 2024-25 as the base profile.

iii) The actual solar, wind and hydro generation profiles and CUFs have been considered from National Electricity Plan 2023 (Volume I Generation).

iv) The capital costs of candidate plants for coal, wind, solar and storage technologies is detailed in the Annexure and are aligned with current market trends and recent price discovery.

v) The year-wise planned capacity tie-up as per BEST is given below.

Table 8: Source wise planned capacity addition (MW) as per BEST

FY	Solar	Wind	DRE	Battery (4 hours)	PSP
2025-26	531	103	2	0	77*
2026-27	0	0	2	0	0
2027-28	0	0	2	0	0
2028-29	0	0	2	0	0
2029-30	0	0	2	150	0
2030-31	0	0	2	0	0
2031-32	0	0	2	0	0
2032-33	0	0	2	0	0
2033-34	0	0	2	0	0
2034-35	0	0	2	0	0
2035-36	0	0	2	0	0
Total	**531**	**103**	**22**	**150**	**77**

*BEST intends to utilize 77MW of already existing Bhira hydro station (154 MW) as a pumped hydro storage plant (PSP)

vi) **Renewable Purchase Obligation (RPO) trajectory**: Ministry of Power vide gazette notification dated 27th September, 2025 had notified the source wise minimum share of consumption of non-fossil sources (renewable energy) by designated consumers till the year 2029-30.

Table 9: Renewable Purchase Obligation (RPO) trajectory as per MoP order

Sl. No.	Year	Wind renewable energy	Hydro renewable energy	Other renewable energy	Distributed renewable energy	Total renewable energy
1.	2024-25	0.67 %	0.38 %	27.35 %	1.5 %	29.91 %
2.	2025-26	1.45 %	1.22 %	28.24 %	2.1 %	33.01 %
3.	2026-27	1.97 %	1.34 %	29.94 %	2.7 %	35.95 %
4.	2027-28	2.45 %	1.42 %	31.64 %	3.3 %	38.81 %
5.	2028-29	2.95 %	1.42 %	33.1 %	3.9 %	41.36 %
6.	2029-30	3.48 %	1.33 %	34.02 %	4.5 %	43.33 %

Further, in view of the country's energy transition goals as well as the long-term net zero target of 2070, it is estimated that the share of RE generation in the generation mix will continue to proportionally increase beyond 2029-30. Therefore, the RPO trajectory is

assumed to rise steadily beyond 2029-30. Hence, the suggested trajectory of Renewable Purchase Requirement up to FY 2035-36 is presented in Table 10.

Table 10: Renewable Purchase Obligation (RPO) trajectory considered for the study

Sl. No.	Year	Wind renewable energy	Hydro renewable energy	Other renewable energy	Distributed renewable energy	Total renewable energy
1.	2025-26	1.45 %	1.22 %	28.24 %	2.1 %	33.01 %
2.	2026-27	1.97 %	1.34 %	29.94 %	2.7 %	35.95 %
3.	2027-28	2.45 %	1.42 %	31.64 %	3.3 %	38.81 %
4.	2028-29	2.95 %	1.42 %	33.1 %	3.9 %	41.36 %
5.	2029-30	3.48 %	1.33 %	34.02 %	4.5 %	43.33 %
6.	2030-31	41.0%			4.5%	45.5%
7	2031-32	42.5%			4.5%	47.0%
8.	2032-33	43.8%			4.5%	48.3%
9.	2033-34	45.0%			4.5%	49.5%
10.	2034-35	46.0%			4.5%	50.5%
11.	2035-36	47.0%			4.5%	51.5%

Based on the trajectory specified, RPO quantum in million units (MUs) from hydro, wind, other (Solar, biomass etc.) and distributed renewable energy (DRE) is calculated and tabulated below:

Table 11: Total Electrical Energy required to meet RPO (MU)

Sl. No.	Year	Wind renewable energy (MU)	Hydro renewable energy	Other renewable energy	Distributed renewable energy	Total renewable energy
1.	**2025-26**	77	65	1497	111	1750
2.	**2026-27**	106	72	1610	145	1933
3.	**2027-28**	134	77	1726	180	2117
4.	**2028-29**	163	79	1831	216	2288
5.	**2029-30**	195	75	1909	253	2431
6.	**2030-31**	2334			256	2590
7.	**2031-32**	2454			260	2714
8.	**2032-33**	2566			264	2830
9.	**2033-34**	2675			267	2942
10.	**2034-35**	2774			271	3045
11.	**2035-36**	2876			275	3151

Table 12: Renewable Energy other than DRE

FY	RE Generation required to meet RPO	RE Generation required to meet RPO	RE Generation available/met (From existing/ planned Contracts)	RPO met (%)	RPO Surplus (+) / Deficit (-)
	(MU)	(%)	(MU)	(%)	(%)
2025-26	1639	30.91%	1824	34.40%	3.49%
2026-27	1788	33.25%	1824	33.92%	0.67%
2027-28	1937	35.51%	1824	33.44%	-2.07%
2028-29	2073	37.47%	1824	32.97%	-4.50%
2029-30	2179	38.83%	1824	32.51%	-6.32%
2030-31	2334	41.00%	1824	32.04%	-8.96%
2031-32	2454	42.50%	1824	31.59%	-10.91%
2032-33	2566	43.80%	1824	31.14%	-12.66%
2033-34	2675	45.00%	1824	30.69%	-14.31%
2034-35	2774	46.00%	1824	30.25%	-15.75%
2035-36	2876	47.00%	1824	29.81%	-17.19%

Table 13: Renewable Energy from DRE

FY	DRE required to meet RPO	DRE required to meet RPO	DRE available	DRE available	Surplus (+)/ Deficit (-)
	(MU)	(%)	(MU)	(%)	(%)
2025-26	111	2.10%	24	0.46%	-1.64%
2026-27	145	2.70%	27	0.50%	-2.20%
2027-28	180	3.30%	29	0.54%	-2.76%
2028-29	216	3.90%	32	0.57%	-3.33%
2029-30	253	4.50%	34	0.61%	-3.89%
2030-31	256	4.50%	37	0.64%	-3.86%
2031-32	260	4.50%	39	0.68%	-3.82%
2032-33	264	4.50%	42	0.71%	-3.79%
2033-34	267	4.50%	44	0.74%	-3.76%
2034-35	271	4.50%	46	0.77%	-3.73%
2035-36	275	4.50%	49	0.80%	-3.70%

As indicated in the tables above, the DISCOM will not be able to meet its RPO requirements from 2027-28 till 2035-36 based on the existing and planned contracts for Renewable Energy other than DRE and will not be able to meet its RPO requirements for DRE from 2025-26 till 2035-36 based on the existing and planned contracts.

7.0 Outcome of the model

7.1 Unserved Energy Projections

Initially, the study has been carried out considering only the existing and planned capacity contracts as per BEST. Considering the existing and planned capacity contracts, the DISCOM will not be able to meet its electrical energy requirement and the total unserved energy for the year 2035-36 has

been estimated as 748 MU. The year-wise likely unserved energy with the existing and planned capacities is given in figure 9.

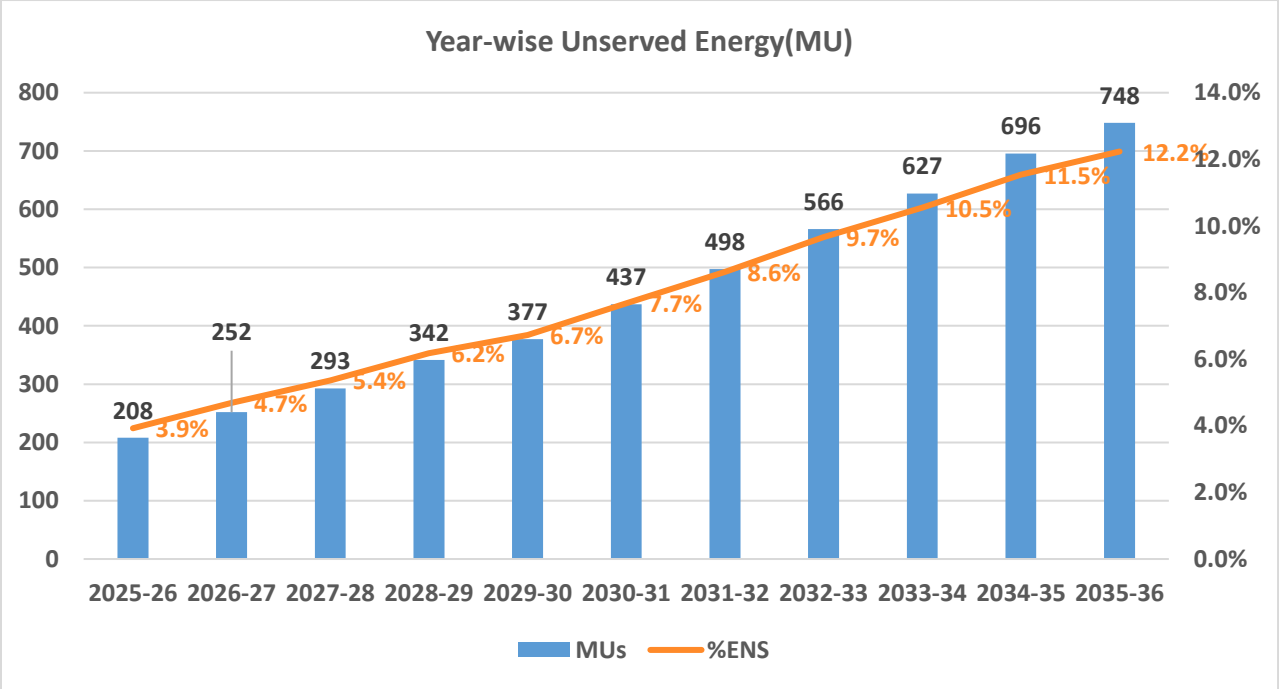


Figure 9: Yearly likely unserved energy (in MU) with the existing and planned capacities

The study has also analyzed the daily and monthly pattern of unserved energy in the year 2035-36 and it can be seen that contracted capacity (existing and planned) is unable to meet the projected electricity demand.

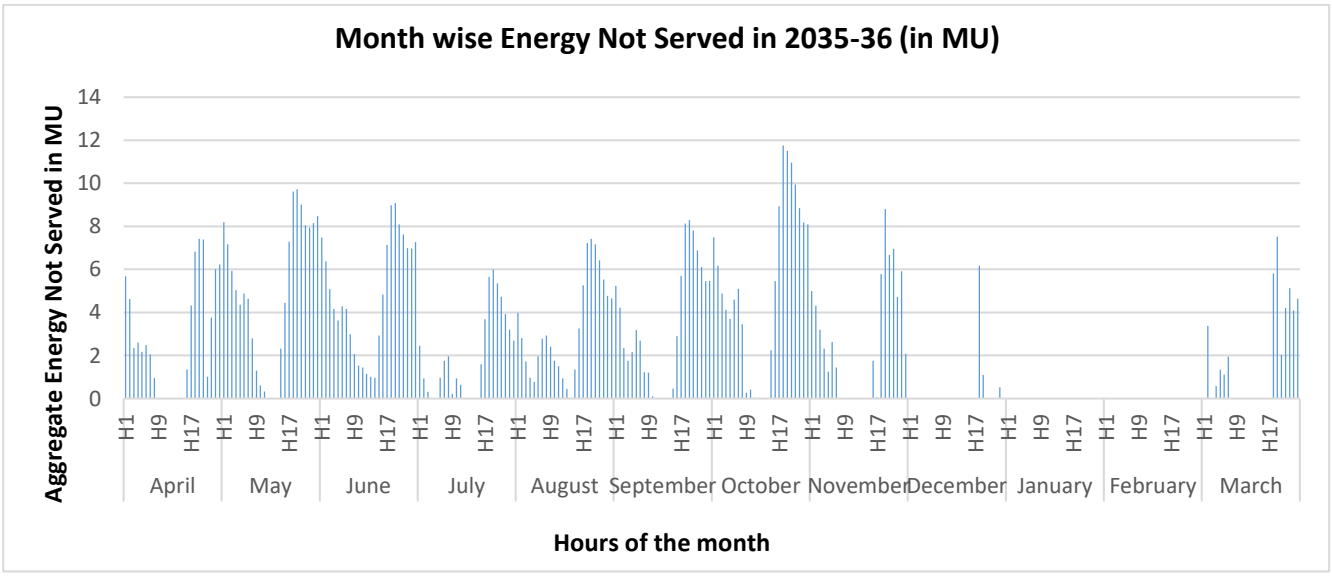


Figure 10 Block-wise Unserved Energy Pattern in MU (2035-36)

The unmet electricity demand occurs majorly during April to November.

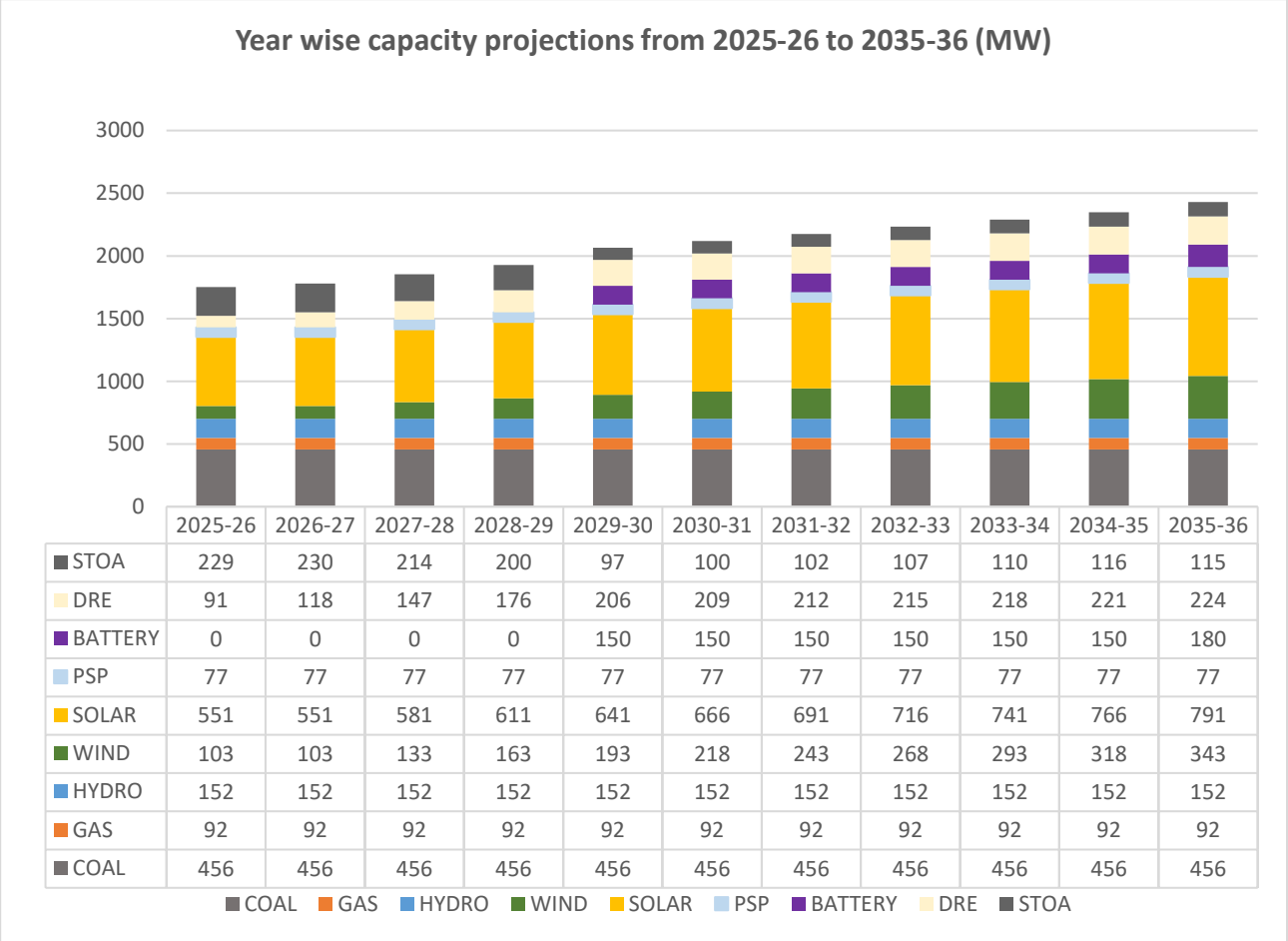
7.2 Options to meet the unserved energy

Based on discussions with BEST officials, the organization does not intend to procure any additional coal-based capacity beyond its existing commitments and are planning to meet its future power requirements primarily through renewable energy sources. To meet this unserved energy, options (i.e., candidate capacities) are given to the model to find the least cost optimal capacity mix required to meet the electricity demand with RPO obligations. The capacity projections for BEST are given below:

Table 14: Year-wise contracted capacity projections (existing + planned + additional) (in MW)

Year	Coal	Gas	Hydro	Wind	Solar	PSP (6 hours)	Battery (4 hours)	DRE	STOA
2025-26	456	92	152	103	551	77	0	91	229
2026-27	456	92	152	103	551	77	0	118	230
2027-28	456	92	152	133	581	77	0	147	214
2028-29	456	92	152	163	611	77	0	176	200
2029-30	456	92	152	193	641	77	150	206	97
2030-31	456	92	152	218	666	77	150	209	100
2031-32	456	92	152	243	691	77	150	212	102
2032-33	456	92	152	268	716	77	150	215	107
2033-34	456	92	152	293	741	77	150	218	110
2034-35	456	92	152	318	766	77	150	221	116
2035-36	456	92	152	343	791	77	180	224	115

The projected year-wise contracted capacity mix is given in the figure below:



	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
STOA	229	230	214	200	97	100	102	107	110	116	115
DRE	91	118	147	176	206	209	212	215	218	221	224
BATTERY	0	0	0	0	150	150	150	150	150	150	180
PSP	77	77	77	77	77	77	77	77	77	77	77
SOLAR	551	551	581	611	641	666	691	716	741	766	791
WIND	103	103	133	163	193	218	243	268	293	318	343
HYDRO	152	152	152	152	152	152	152	152	152	152	152
GAS	92	92	92	92	92	92	92	92	92	92	92
COAL	456	456	456	456	456	456	456	456	456	456	456

Figure 11 Projected Contracted Capacity Mix Year-wise (MW)

The STOA/MTOA requirement can be fulfilled through power procurement from market or bilateral agreements. The STOA/MTOA value reflects the peak value requirement and seasonal banking requirements in terms of MW.

Reliability studies have been conducted based on the projected capacity for the year 2035-36. The analysis confirms that the projected capacity meets the reliability criteria specified in the National Electricity Plan (NEP), with the Loss of Load Probability (LoLP) and Normalised Energy Not Served (NENS) remaining within the permissible limits of 0.2% and 0.05%, respectively [as specified in the National Electricity Plan (NEP)].

As per the Resource Adequacy studies, the likely total projected contracted capacity for the year 2035-36 is around 2,430 MW which consists of 456 MW from coal, 92 MW from gas, 152 MW from hydro, 343 MW from Wind, 791 MW from solar, 224 MW from Distributed Renewable Energy (DRE), 77 MW of PSP (6 hours), 180 MW of BESS (4 hours) and 115 MW of STOA. This capacity is likely to meet the projected electricity demand with prescribed reliability criteria. BEST may explore the possibility of meeting storage requirement from PSPs.

It is important to note that any deviations in the commissioning schedule of the planned capacity could result in a situation where the DISCOM is unable to meet the projected peak demand and energy requirements identified in this study with the available resources. Such changes may also increase the cost of reliably meeting the DISCOM's power demand.

The Planning Reserve Margin (PRM) for BEST has been assessed at 12%. Furthermore, the projected/contracted capacity is in compliance with the stipulated Renewable Purchase Obligation (RPO) targets.

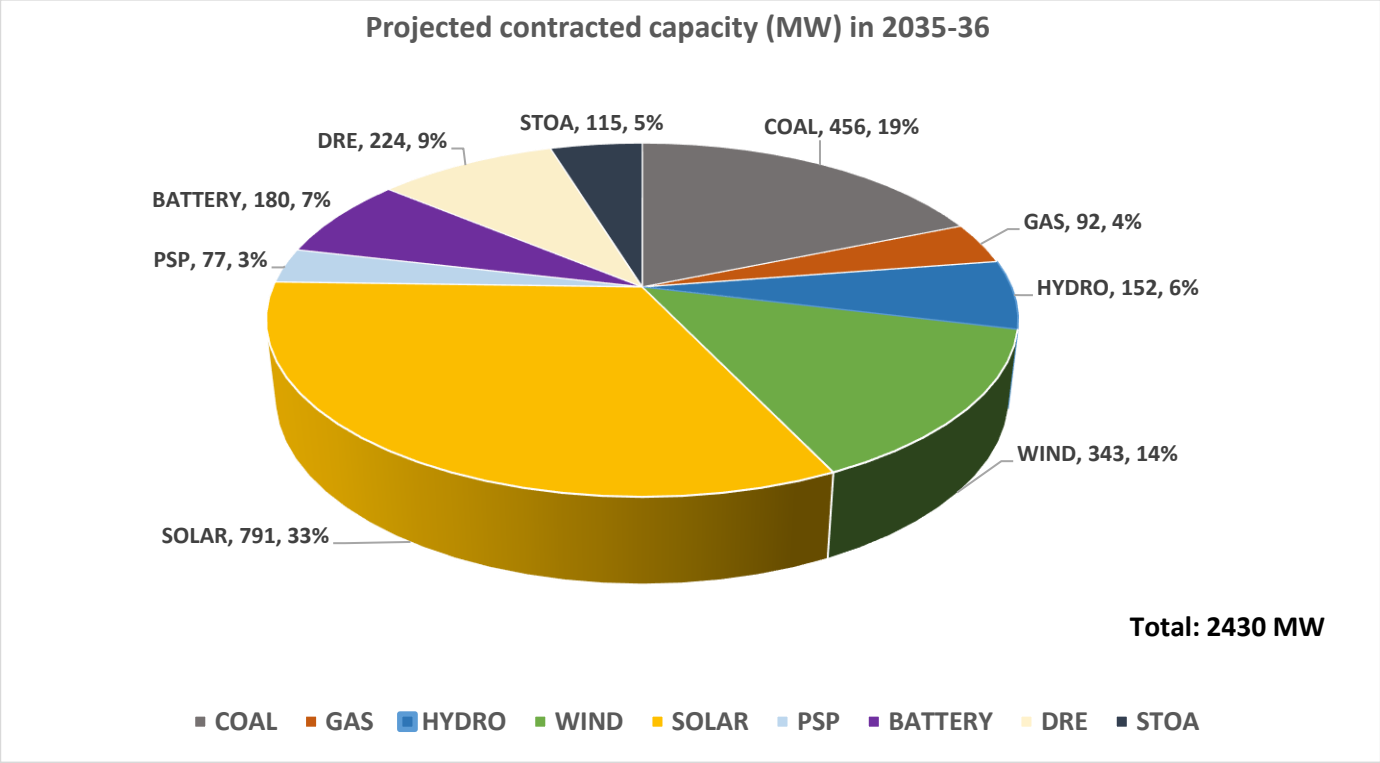


Figure 12: Projected Contracted Capacity Mix in 2035-36

As per the study, the utility needs to contract following capacities (already planned by BEST and additional requirement) per year till 2035-36 to meet its demand reliably.

Table 15 Year wise Capacity Addition (in MW)

	Solar		Wind		DRE		BESS (4 hours)		PSP	STOA
Year	Planned Contracts	Additional Requirement	Planned Contracts	Additional Requirement	Planned Contracts	Additional Requirement	Planned Contracts	Additional Requirement	Planned Contracts	Additional Requirement
2025-26	531	0	103	0	2	71	0	0	77	229
2026-27	0	0	0	0	2	25	0	0	0	230
2027-28	0	30	0	30	2	27	0	0	0	214
2028-29	0	30	0	30	2	27	0	0	0	200
2029-30	0	30	0	30	2	28	150	0	0	97
2030-31	0	25	0	25	2	1	0	0	0	100
2031-32	0	25	0	25	2	1	0	0	0	102

2032-33	0	25	0	25	2	1	0	0	0	107
2033-34	0	25	0	25	2	1	0	0	0	110
2034-35	0	25	0	25	2	1	0	0	0	116
2035-36	0	25	0	25	2	1	0	30	0	115
TOTAL	**531**	**240**	**103**	**240**	**22**	**184**	**150**	**30**	**77**	

The share of non-fossil fuel-based capacity in the electricity generation mix is projected to be around 73% from 2025-26 to 2035-36. The projected gross electricity generation mix for the DISCOM is shown in Figure 13.

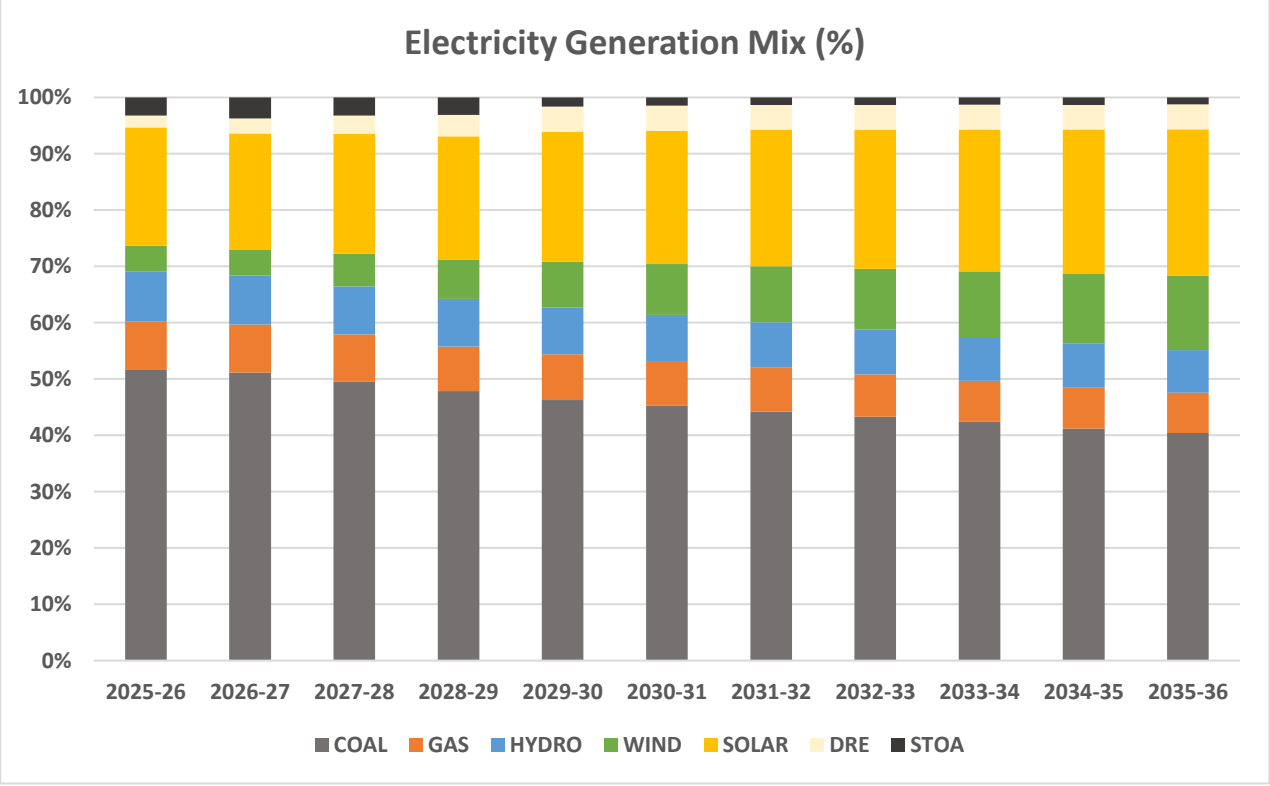
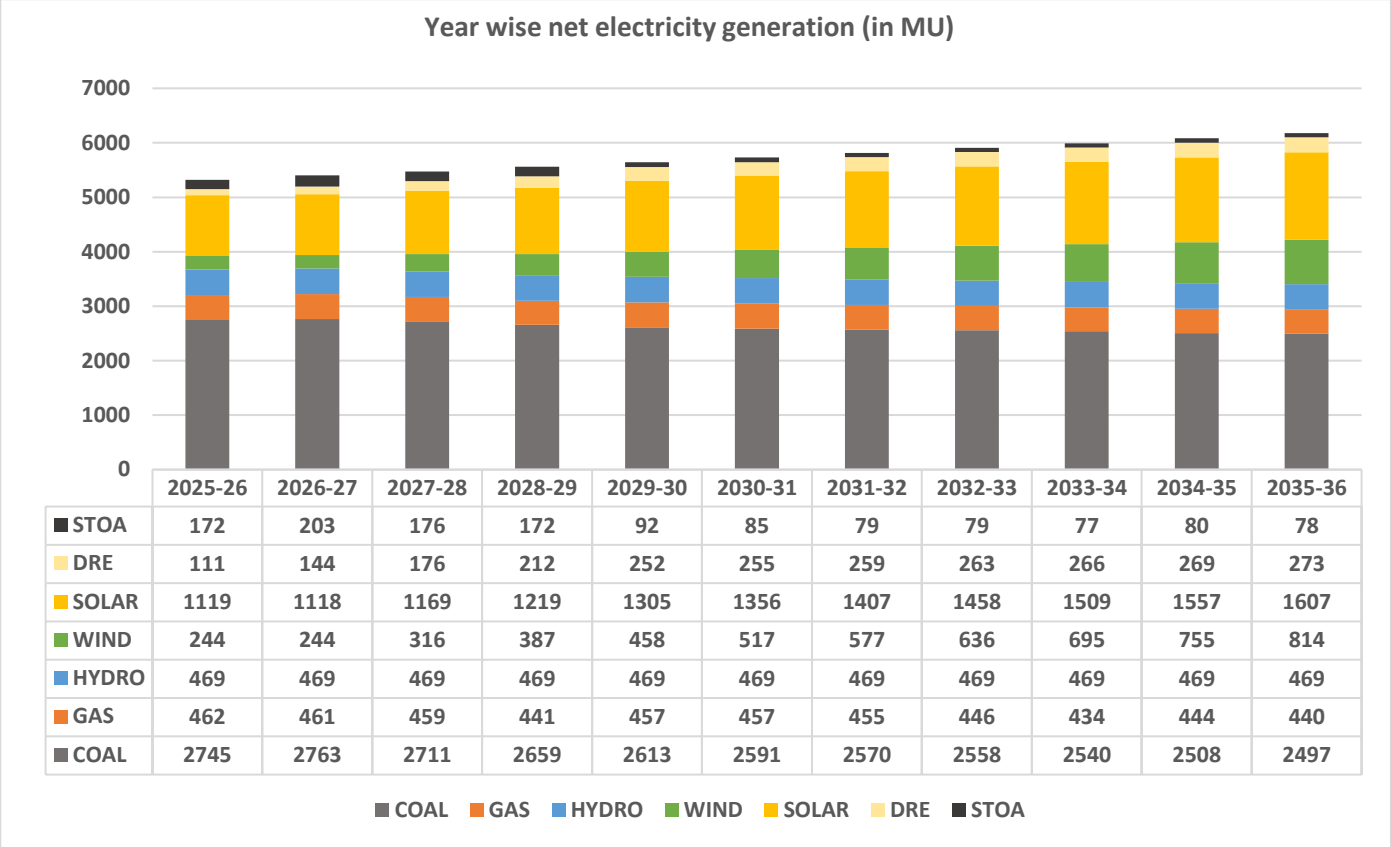


Figure 13: Year-wise projected gross electricity generation mix (in %)



	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
STOA	172	203	176	172	92	85	79	79	77	80	78
DRE	111	144	176	212	252	255	259	263	266	269	273
SOLAR	1119	1118	1169	1219	1305	1356	1407	1458	1509	1557	1607
WIND	244	244	316	387	458	517	577	636	695	755	814
HYDRO	469	469	469	469	469	469	469	469	469	469	469
GAS	462	461	459	441	457	457	455	446	434	444	440
COAL	2745	2763	2711	2659	2613	2591	2570	2558	2540	2508	2497

Figure 14: Year-wise projected gross electricity generation (in GWh)

7.3 Day-wise Surplus Capacity (in MW)

The pattern of surplus capacities has been observed as given in Figure 15. Available Surplus capacity can be due to seasonal variation of electricity demand. This capacity can be used for banking arrangements or shared with other states/DISCOMS through bilateral agreements / Pushp portal, thereby reducing the fixed cost burden on the utility resulting in reduction in the cost for consumer. BEST is likely to have surplus capacity mainly during the off-peak electricity demand months (November to March), which can be shared with other states/DISCOMS. The utility is likely to have a surplus in range of 65 MW to 200 MW during December to January in 2028-29, which can be shared with other states/Discoms.

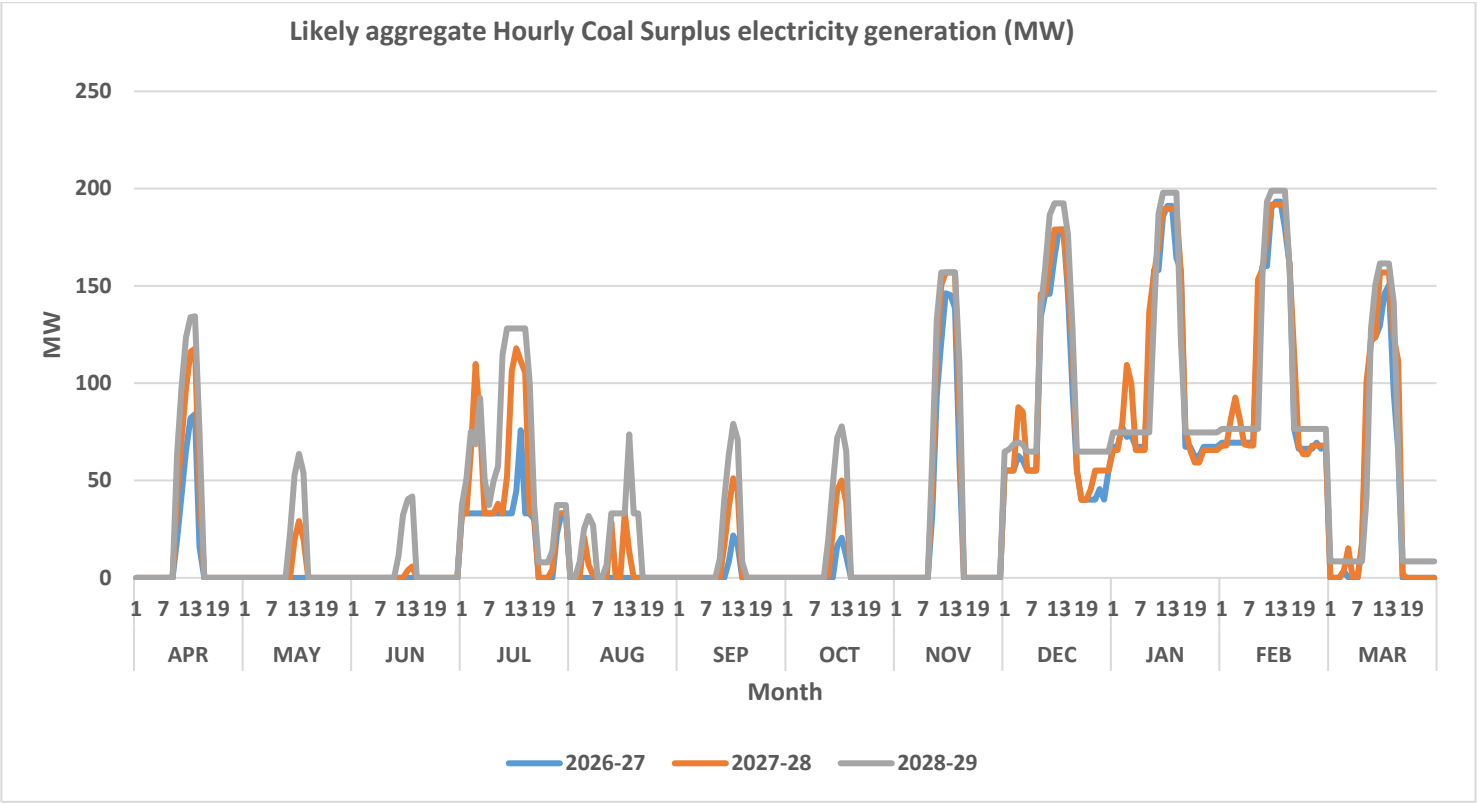


Figure 13 Surplus Coal Capacity Year-wise (MW)

8.0 Conclusions

Based on the Resource Adequacy studies carried out for BEST up to the year 2035-36, the following conclusions may be drawn:

1. The study has been done based on the hourly electricity demand pattern of the year 2024-25. Based on the electricity demand pattern, it is seen that the peak demand season is during solar hours in the month of May, 2024.
2. The study has considered electrical energy requirement projections as per BEST, which envisages that the annual electrical energy requirement of the DISCOM is likely to grow at a CAGR of about 1.4% while the peak electricity demand for the utility is likely to grow at a CAGR of about 0.8% for the period of 2025-26 to 2035-36.
3. Considering only the existing and planned capacity addition by BEST, BEST is likely to witness energy deficit ranging from 208 to 748 MUs in different years from 2025-26 to 2035-36.
4. The Resource adequacy studies have projected likely optimal capacity mix for future years till 2035-36 which is able to meet anticipated demand reliably at every instance. Based on the study, the likely total projected contracted capacity for the year 2035-36 is around 2,430 MW which consists of 456 MW from coal, 92 MW from gas, 152 MW from hydro, 343 MW from Wind, 791 MW from solar, 224 MW from Distributed Renewable Energy (DRE), 77 MW of PSP (6 hours), 180

MW of BESS (4 hours) and 115 MW of STOA. This capacity shall be able to meet the projected demand with prescribed reliability criteria.

5. The contracted capacity in March, 2025 comprises of about 33% from non-fossil sources. In 2035-36, the non-fossil based (that includes hydro, solar, Wind, DRE) capacity are likely to constitute around 73 % of the total contracted capacity.
6. The DISCOM needs to contract STOA/MTOA of around 97 MW to 229 MW in different years as outlined in the report. The STOA/MTOA requirement can be fulfilled through power procurement from market or bilateral agreements. The STOA/MTOA value reflects the peak value requirement and seasonal banking requirements in terms of MW.
7. The projected capacity and generation mix outlined in the report, meet the utility's RPO requirements for the years 2025-26 to 2035-36.
8. The Planning Reserve Margin (PRM) for BEST has been assessed at 12%. Further, the study indicates year-wise short-term/medium-term/bilateral requirements to meet the demand optimally.
9. It is likely that BEST may have surplus capacity available during the months from November to March which can be shared with other utilities/states through banking/bilateral arrangements, including Pushp portal
10. Accurate electricity demand assessment is fundamental to capacity expansion modelling and directly impacts the Resource Adequacy (RA) study outcomes. To achieve realistic and data-driven results, States/DISCOMS are strongly encouraged to adopt scientific tools and robust methodologies for demand forecasting.
11. Timely commissioning of planned capacities is critical to ensuring that the state/DISCOMS can meet the projected peak demand and energy requirements identified in this study. Any deviation from the planned schedule may lead to resource shortfalls and could significantly increase the cost of reliably meeting the DISCOMS’s power demand.

Annexure

Planned Future Contracted (MW) considered in the study

Sr. No.	Tied capacity name	Type of generation	Expected COD	Tentative BEST share (in MW)
1.	SECI-Solar	Solar	2025-26	531
2.	SECI-Wind	Wind	2025-26	103
3.	Bhira-PSP*	PSP	2025-26	77
4.	BESS (4 hrs)	Storage	2029-30	150

*BEST intends to utilize 77MW of already existing Bhira hydro station (154 MW) as a pumped hydro storage plant (PSP)

Assumption for Resource Adequacy Studies

1. Electricity Demand & peak requirement: As per projections made by BEST.
2. Demand Profile: Based on hourly demand profile of 2024-25.
3. Existing & Planned Capacity: As per the information shared by the utility.
4. Cost parameters: based on information in National Electricity Plan.

RE CUF considered

Hydro	Wind	Solar	DRE
35 %	27%	22-23%	14%

Technical Parameters

Technology	Type	Availability (%)	Ramping (%/min)	Min. Technical. (%)
Coal/ Lignite	Existing/Planned	85	1	55
	Candidate	85	1	55
Gas	Existing	61	3	40
Hydro	Existing/Planned/ Candidate	As per available hourly generation profile	100	-
Solar	Existing/Planned		-	-
	Candidate		-	-
Wind	Existing/Planned		-	-
	Candidate		-	-
Pumped storage	Existing/Planned	95	50	-
	Candidate		50	-
BESS	Candidate	98	NA	-

Technology	Type	Heat Rate (MCal/MWh)		Aux. Consum. (%)
		At max loading	At min loading	
Coal	Existing/ Planned	2300 to 2879	2438 to 3052	7.0
	Candidate (SC & USC)	2060 to 2125	2183 to 2253	6.5
Gas	Existing	2000 to 2900	2260 to 3277	2.5
Hydro	Existing/ Planned	-	-	0.7
	Candidate	-	-	0.7
Pumped Storage	Existing/ Planned	-	-	pump efficiency 80 %
	Candidate	-	-	
BESS	Candidate	-	-	Round trip losses 12%

Transmission Parameters

A single node has been considered for the purpose of study with all generating units and demand connected to the node. No transmission bottleneck has been considered for the study. Interstate ATC limit has not been considered in the study.

Financial Parameters

Following cost parameters have been assumed:

Resource	Capex (in ₹/MW)	O&M Fixed Cost (in ₹/MW/year)	Construction Time (in years)	Amortization /Life time (in years)
Coal	12 Cr	30 lakh	4	25
Solar	4.5 to 4.0 Cr	1 % of Capex	1	25
Wind (Onshore)	7.5 Cr	1% of Capex	2	25
BESS (4-Hour)	4.98 Cr to 3.00 Cr	5.9 lakh	1	15