



**Report on
Resource Adequacy Plan
(Generation) for
Torrent Power (DNH&DD)
(2025-26 to 2035-36)
(Version 1.0)**

March 2026

**Government of India
Ministry of Power
Central Electricity Authority**

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Disclaimer

This Resource Adequacy Study for Torrent Power (DNH&DD) has been carried out based on data and inputs provided by Torrent Power, DNH&DD. The findings, analysis and conclusions presented in this report are contingent upon the accuracy, completeness and timeliness of the information furnished by the distribution utility. 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 the Union Territory of DNH&DD 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 financial implication if any, rests entirely with the UTs/utilities.

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 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 electricity demand and electrical energy requirements.

As per the Resource Adequacy Guidelines dated 28th June 2023, each Distribution Licensee shall prepare 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 notified the Renewable Energy Consumption Obligation (RCO) trajectory up to 2029-30 vide gazette notification dated 27th September 2025, which mandates that a specified portion of electrical energy consumption must be met from non-fossil /renewable energy sources.

The electrical energy requirement and peak electricity demand for DNH&DD, as furnished by DNH&DD, are projected to increase with a CAGR of 4.1 % and 4.7% respectively, from actual 2024-25 to 2035-36. For satisfying resource adequacy, i.e., meeting the electricity demand reliably and at an affordable cost, the UT needs to methodically plan its capacity expansion either by investing in new generation or by procuring power. In view of the reduction in cost of solar panels and newer technology options like energy storage systems, planning for a long-term optimal generation capacity mix gains tremendous importance so that the future generation capacity mix is cost-effective as well as environmentally friendly.

The study for DNH&DD, based on existing contracted capacity and planned capacity additions, indicates that the available capacity may be sufficient to meet the projected future demand. However, the UT, with its existing and planned Renewable Energy (RE)- based capacity, may be unable to fulfil its Renewable Energy Consumption Obligation targets.

To find out the least cost option for generation capacity expansion for the period 2025-26 to 2035-36, generation expansion study has been carried out 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, variation in RE generation 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 DNH&DD along with RCO constraints for Solar, Wind and DRE technologies. The Renewable capacities have been assessed in view of adherence to the RCO notified by the Ministry of Power, considering the fungibility among different sources.

The Resource adequacy studies have projected a likely optimal capacity mix for future years till 2035-36, which shall be able to reliably meet the anticipated electricity demand. Based on the study, the likely total projected contracted capacity for the year 2035-36 is around 4,198 MW, which consists of 1,264 MW from coal, 242 MW from gas, 190 MW from Nuclear, 300 MW from solar, 419 MW from DRE, 960 MW from RTC(RE) source and 268 MW/1072 MWh from Storage (BESS 4 hr), 69 MW from PSP and 487 MW from MTOA/STOA. This capacity shall be able to meet the projected electricity demand with prescribed reliability criteria.

1.0 Introduction

The Ministry of Power notified the 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 were notified in June 2023 by the Ministry of Power in consultation with the 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 an 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 the demand-supply situation in the grid precisely due to high seasonality and intermittency in RE generation. Resource Adequacy exercise may also help in the assessment of capacity requirements to be tied up or contracted on a long-term, medium-term, and short-term basis.

Further, Ministry of Power vide notification dated 27th September 2025, had notified the RCO trajectory for Designated Consumers/Discoms. Based on the trajectory specified, RCO quantum in million units (MUs) has been calculated to find additional quantum of renewable capacity that the UT/Discoms have to contract in addition to the existing/planned capacity to meet their RCO targets.

To support the UT in fulfilling the Resource Adequacy Guidelines and complying with the Renewable Energy Consumption Obligation (RCO) notification, CEA has carried out the RA study for the UT of DNH&DD based on inputs furnished by DNH&DD. 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 electricity demand on a 24x7 basis, considering variations in demand, variation in RE generation, and forced outage of thermal capacities. The study also assesses the Planning Reserve Margin (PRM) required by the UT to account for the aforementioned uncertainties, ensuring that demand can be reliably met throughout the year.

2.0 DNH&DD RA Study (from 2025-26 to 2035-36)

2.1 Present Power Scenario in DNH&DD

The power supply position for DNH&DD from 2022-23 to 2024-25 is given in Table 1:

Table 1: Power Supply Position of DNH&DD

Power Supply Position						
Year	Energy required (MU)	Energy supplied (MU)	Year On Year Growth %	Peak Demand (MW)	Peak Met (MW)	Year On Year Growth %
2022-23	10018	10018		1278	1278	
2023-24	10164	10164	1.46%	1327	1327	3.83%
2024-25	10852	10852	6.77%	1390	1390	4.75%

As per the data provided by Torrent Power, DNH&DD, as of March 2025, the total contracted capacity of DNH&DD is 1714 MW. Out of the total contracted capacity (CC), the share of non-fossil fuel-based CC is about 12%.

The fuel-wise contracted capacity as on 31st March 2025, is given in Table 2 and Figure. 1.

Table 2: Fuel-wise Contracted Capacity as of March 2025

Source	Contracted Capacity (MW)	Percentage
COAL	1264	74%
GAS	242	14%
NUCLEAR	190	11%
Solar DRE	18	1%
Total	1714	100%

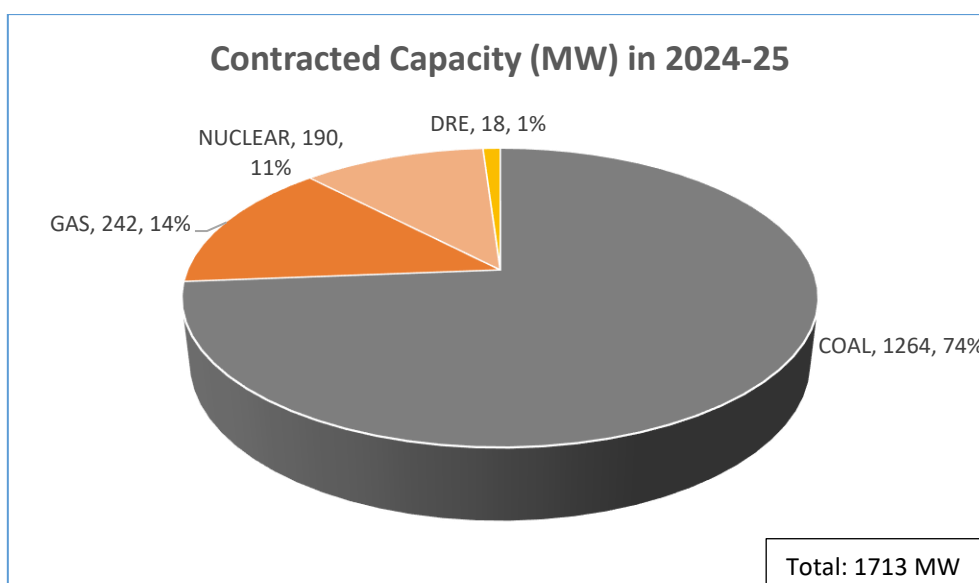


Figure 1: Fuel-wise Contracted Capacity (in MW) as on 31st March 2025

2.2 Analysis of Electricity Demand in 2024-25

The hourly demand pattern of 2024-25 was analyzed, and it was observed that the peak demand season for the UT is typically during the month of February. DNH&DD witnesses peak electricity demand during non-solar hours. The month-wise average hourly electricity demand observed for the year 2024-25 is shown in Figure 2.

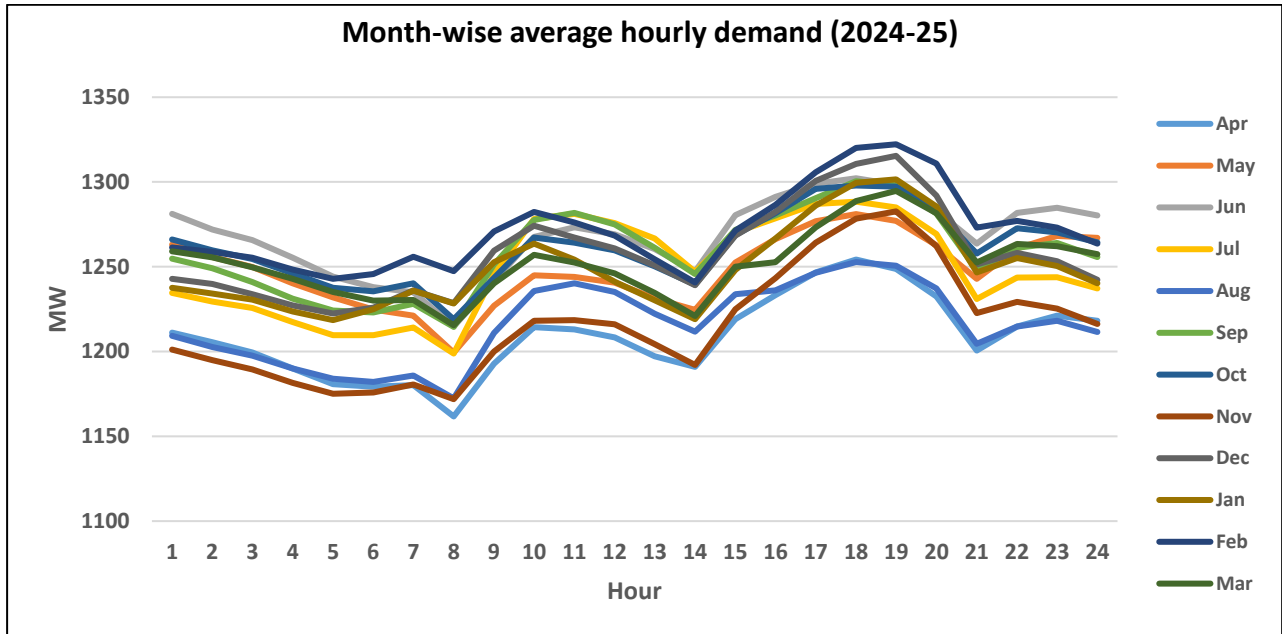


Figure 2: Month-wise Average Hourly Demand Variation for 2024-25

From the hourly demand data of 2024-25, the daily peak demand during solar hours and non-solar hours is plotted in Figure 3. Solar and non-solar peak demand display near-parallel trajectories, indicating similar underlying demand dynamics. However, the non-solar peak demand exceeds the solar peak in high demand season, suggesting that non-solar load continues to set the effective system peak in most periods.

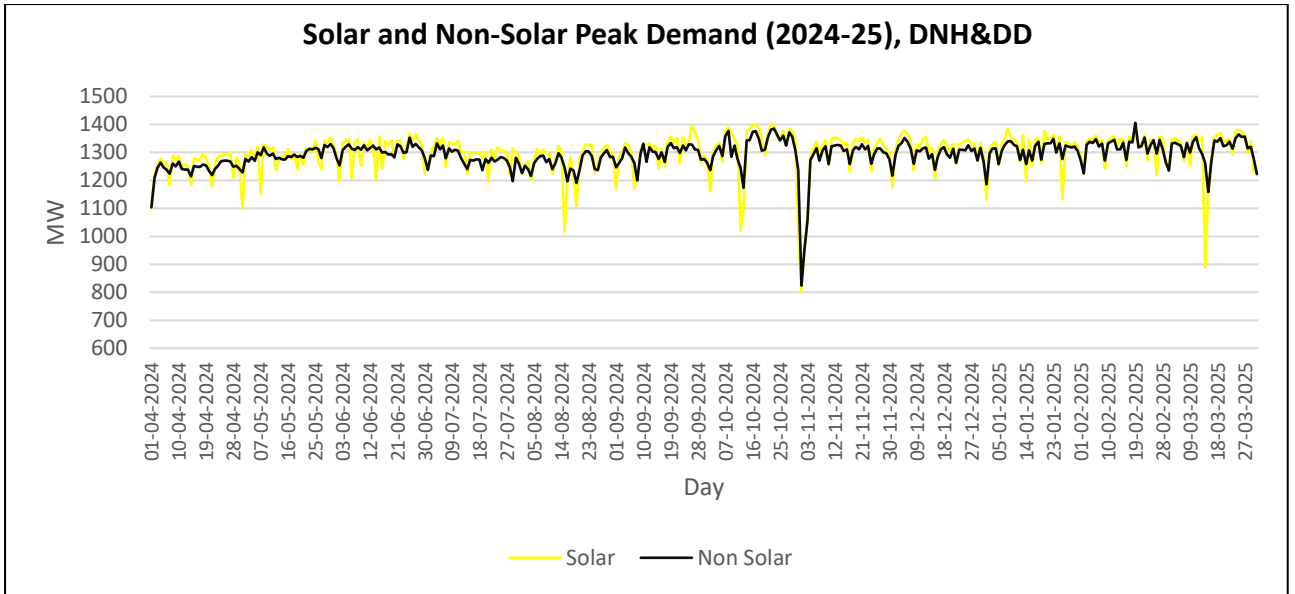


Figure 3: Solar and non-solar peak in MW for the year 2024-25

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 purposes as it is necessary to ensure resource adequacy during such instances with an optimal mix of long-term, medium-term and short-term contracts. The Frequency Distribution of the hourly demand profile for 2024-25 is shown in Figure 4.

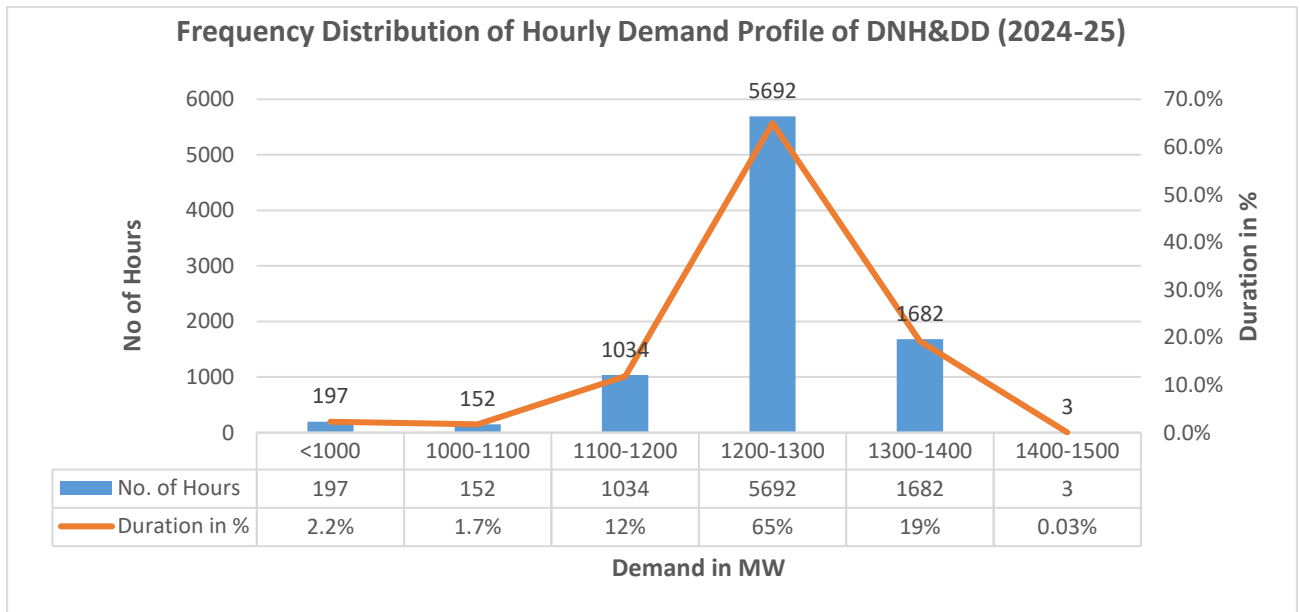


Figure 4: Frequency Distribution of hourly demand profile of 2024-25

3.0 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 electricity demand at every instance of time while ensuring the most efficient use of resources.

The major aspects considered in the planning process are:

- i) To supply 24x7 reliable power to the consumers
- ii) To achieve the objectives of all policies of the Government of India, such as the RCO trajectory, RE capacity addition plan, 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

3.1 Generation Expansion Planning Tool -STELLAR

Central Electricity Authority (CEA) has successfully developed an indigenously built generation expansion planning tool that integrates long-term capacity planning, economic dispatch, and reliability analysis into a unified framework. Named “STELLAR” (Strategic Expansion for Long-Term Load Adequacy and Resilience), the tool represents a significant advancement in power system modelling and planning. STELLAR is a state-of-the-art optimization model framework specifically designed to support long-term decision-making in the electricity sector, with a focus on ensuring resource adequacy, operational resilience, and cost-effective system evolution in line with India's energy transition goals.

STELLAR serves as a comprehensive and robust platform for long-term generation and transmission planning, supporting informed policymaking and investment strategies in India's evolving power sector. The salient features of STELLAR include representative-day modelling, co-optimization of energy and ancillary services, demand response modelling, and reliability modelling.

The schematic diagram of the software is given in Figure 5.

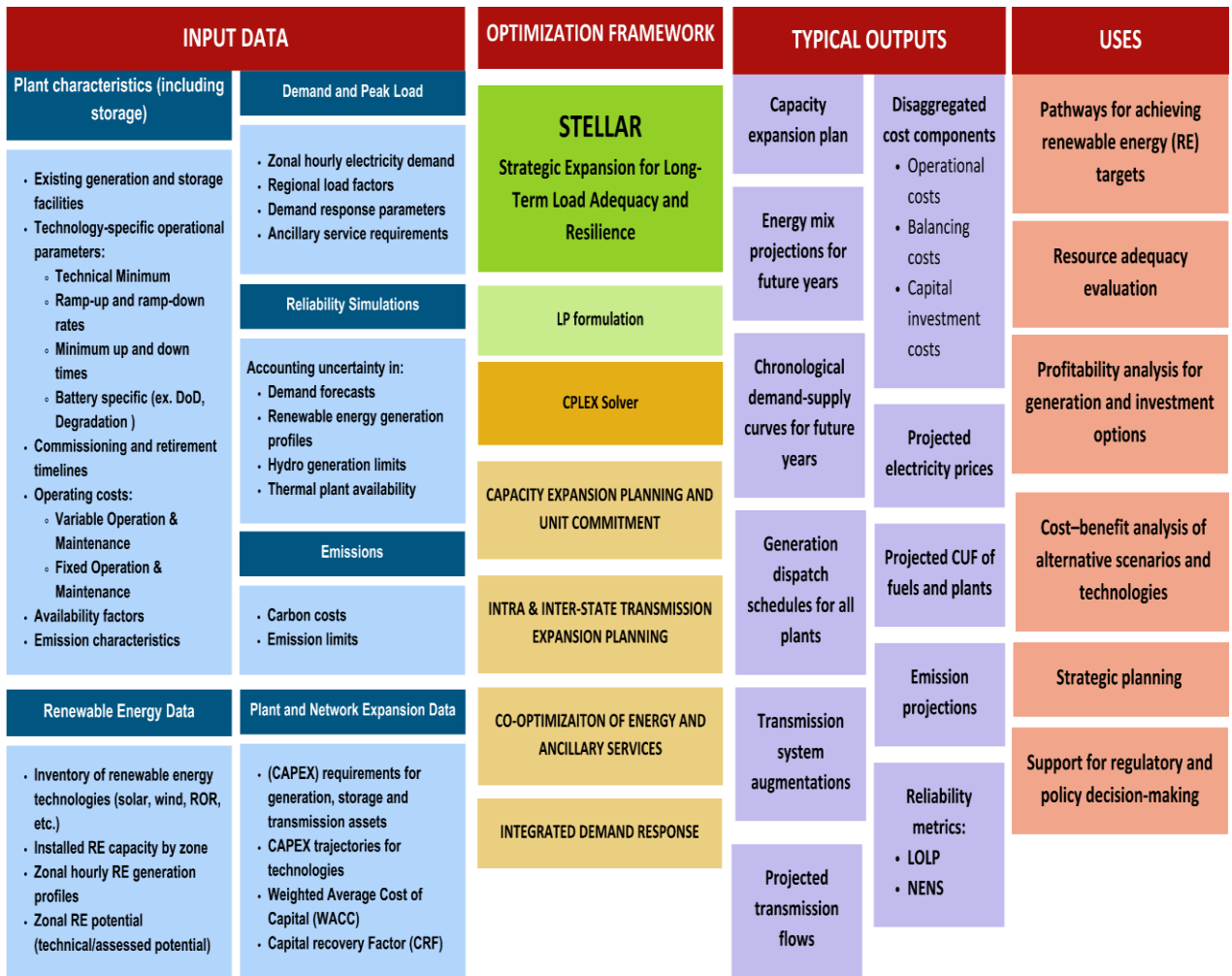


Figure 5: Schematic Diagram

4.0 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 instance 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 not being served, calculated in megawatt-hours (MWh). The metric can be normalised (i.e., divided by total system energy requirement) to create a Normalised Energy Not Served (NENS) metric.

Monte Carlo/Stochastic simulation has been used to account for the uncertainty associated with various generation resources and demand. It is an approach that 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 the economic dispatch model. Monte Carlo simulation helps in analysing the randomness associated with RE energy resource, demand pattern changes and forced outages of the plant. A large number of random samples of these variables is simultaneously simulated to ascertain system reliability indices (i.e. Loss of Load Probability, LOLP and Energy Not Served, ENS) and the system robustness in case of the 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 to adequately address 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 generally expressed as a certain percentage of the projected peak electricity demand.

4.1 Variation in electricity demand

The variation in electricity demand pattern for the last two years, viz. 2023-24 and 2024-25 (considering 2023-24 as the base year), has been analyzed. The electricity demand pattern variation across 2023-24 and 2024-25 is shown in Figure 6.

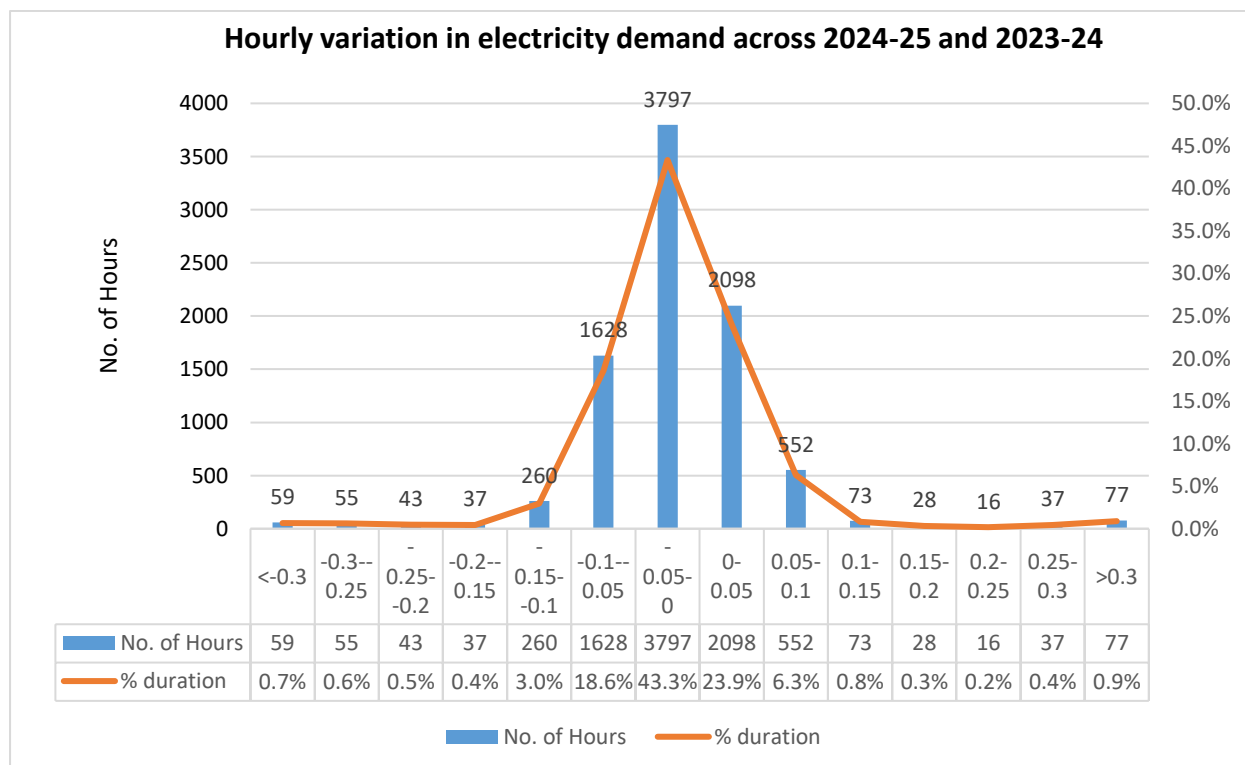


Figure 6: Hourly Variation in electricity demand across years

It can be observed that the hourly demand typically varies within $\pm 10\%$ for $\sim 92\%$ of instances (8060 Hours). This variation is primarily due to temperature, weather parameters or any

random outages of transmission lines and generating units, etc. This variation has been captured in the reliability study by incorporating a variation of $\pm 10\%$ in the projected hourly demand for the future years by introducing a random variable (with normal distribution) for demand as per observed behavior over the years.

4.2 Variation in RE Generation

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

4.3 Forced Outage of Thermal Generators

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

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

5.0 Inputs/Assumptions for the Study

- i) The STELLAR model operates using a representative day’s methodology, in which a subset of days is selected based on the variability in demand and renewable energy (RE) generation profiles. These representative days are then used for simulation instead of modelling all 365 days in a year, thereby reducing computational complexity while retaining accuracy in system behavior.

The STELLAR tool includes a dedicated module that takes 365 days of hourly input data and based on clustering and similarity analysis, identifies the optimal set of representative days. In the current framework, the model selects 3 representative days per month, resulting in a total of 36 representative days for the full year.

The Model also identifies the profile of Solar and wind during these representative days, which are used in the simulation.

- ii) The peak electricity demand and electrical energy requirements of DNH&DD, as furnished by DNH&DD, have been considered for the study and are given in Table 3:

Table 3: Electricity demand projections as per Torrent Power, DNH&DD

Year	Electrical Energy Requirement Projections		Peak Electricity Demand Projections	
	(MU)	(%)	(MW)	(%)
2024-25*	10852		1390	
2025-26 (till Feb) *	10250	-	1416	1.9%

2026-27	11731	4.0%	1540	5.3%
2027-28	12178	3.9%	1604	4.9%
2028-29	12644	3.9%	1683	4.9%
2029-30	13134	3.9%	1754	4.8%
2030-31	13652	3.9%	1833	4.7%
2031-32	14200	3.9%	1919	4.7%
2032-33	14782	3.9%	2017	4.8%
2033-34	15406	4.0%	2115	4.8%
2034-35	16080	4.0%	2205	4.7%
2035-36	16819	4.1%	2302	4.7%

* Values are actual electricity demand

- iii) Future demand profile till the year 2035-36 has been projected using the demand profile for the year 2024-25 as the base profile.
- iv) The actual solar and wind profiles have been referred from the generation profile given by DNH&DD.
- v) The capital cost of candidate plants for coal, solar, and battery/PSP technologies is detailed in the Annexure and is in alignment with current market trends and recent price discovery.
- vi) The planned capacity has been considered based on the tie-up information as furnished by DNH&DD. The same is summarised in Table 7, and details are furnished in Annexure.

Table 4: Source-wise planned capacity addition in MW

Years	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
DRE	115	9	9	10	10	12	12	13	14	10	10
Solar	-	-	100	200	-	-	-	-	-	-	-
RE RTC	-	-	300	300	-	-	-	-	-	-	-

- vii) **Renewable Energy Consumption Obligation (RCO) trajectory:** Ministry of Power vide gazette notification dated 27th September 2025, had notified the source-wise minimum share of consumption of renewable energy till 2029-30. In line with the recent notification, the studies have been carried out based on the trajectory mentioned in the RCO notification till 2030. 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 RCO trajectory is assumed to rise steadily beyond 2029-30. The following RCO trajectory in line with MoP notification has been considered till 2035-36.

Table 5: Renewable Energy Consumption Obligation (RCO) trajectory (in %) 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%	2.10%	33.01%
2	2026-27	1.97%	1.34%	29.94%	2.70%	35.95%
3	2027-28	2.45%	1.42%	31.64%	3.30%	38.81%
4	2028-29	2.95%	1.42%	33.10%	3.90%	41.36%
5	2029-30	3.48%	1.33%	34.02%	4.50%	43.33%
6	2030-31	41.00%			4.50%	45.50%
7	2031-32	42.50%			4.50%	47.00%
8	2032-33	43.80%			4.50%	48.30%
9	2033-34	45.00%			4.50%	49.50%
10	2034-35	46.00%			4.50%	50.50%
11	2035-36	47.00%			4.50%	51.50%

6.0 Outcome of the model

Initially, the study was carried out considering only the existing and planned capacity contracts. From the study, it has been observed that the existing and planned capacities may not be sufficient to reliably meet the electricity demand and the UT may not be able to fulfil the Renewable Energy Consumption Obligations from the year 2025-26 onwards.

6.1 Investment options to meet the RCO

Capacity Investment options (i.e., candidate capacities) have been given to the model to find the least cost optimal capacity mix required to meet the demand while fulfilling the RCO obligations. The capacity projections (existing, planned, and to be tied up) for DNH&DD are given in Table 6.

Table 6: Year-wise cumulative contracted capacity projections (existing, planned, to be tied up in MW)

	Coal	Gas	Nuclear	Solar	DRE	RTC	PSP(6h)	BESS (4h)	MTOA/STOA*	Total
2026-27	1264	242	190	0	169	0	0	0	519	2384
2027-28	1264	242	190	100	216	300	0	0	375	2686
2028-29	1264	242	190	300	266	600	0	79	274	3215
2029-30	1264	242	190	300	320	600	64	79	312	3371
2030-31	1264	242	190	300	334	600	69	79	384	3461
2031-32	1264	242	190	300	349	685	69	93	422	3613
2032-33	1264	242	190	300	364	741	69	136	442	3748
2033-34	1264	242	190	300	381	799	69	183	464	3892
2034-35	1264	242	190	300	399	862	69	234	488	4047
2035-36	1264	242	190	300	419	960	69	268	487	4198

*MTOA/STOA gives the yearly requirement

The STOA/MTOA requirement can be fulfilled through power procurement from the market or bilateral agreements. The STOA/MTOA value reflects the peak value requirement or seasonal banking requirements in terms of MW. The projected contracted capacity mix, year-wise, is given in Figure 7.

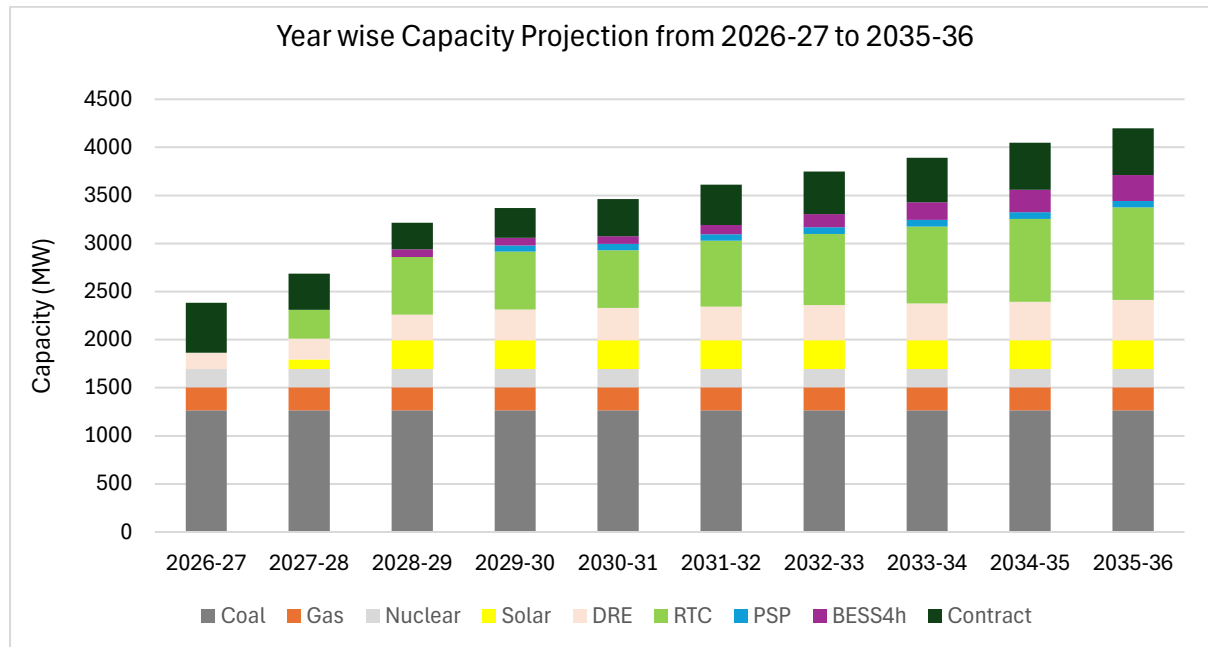


Figure 7: Year-wise Projected Contracted Capacity (MW)

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 Not-Served Energy (NENS) remaining within the permissible limits of 0.2% and 0.05%, respectively.

The Resource adequacy studies have projected a likely optimal capacity mix for future years till 2035-36, which shall be able to meet the anticipated electricity demand reliably. Based on the study, the likely total projected contracted capacity for the year 2035-36 is around 4198 MW, which consists of 1264 MW from coal, 242 MW from gas, 190 MW from Nuclear, 300 MW from solar, 419 MW from DRE, 960 MW from RTC(RE) source, 268 MW/1072 MWh from Storage (BESS 4Hr), 69 MW from PSP and 487 MW from contracts. This capacity shall be able to meet the projected demand with prescribed reliability criteria and to comply with the stipulated Renewable Energy Consumption Obligation (RCO) targets. Based on the capacity addition, the PRM comes out to be 7.5%. The Capacity mix required by 2035-36 is shown in Figure 8.

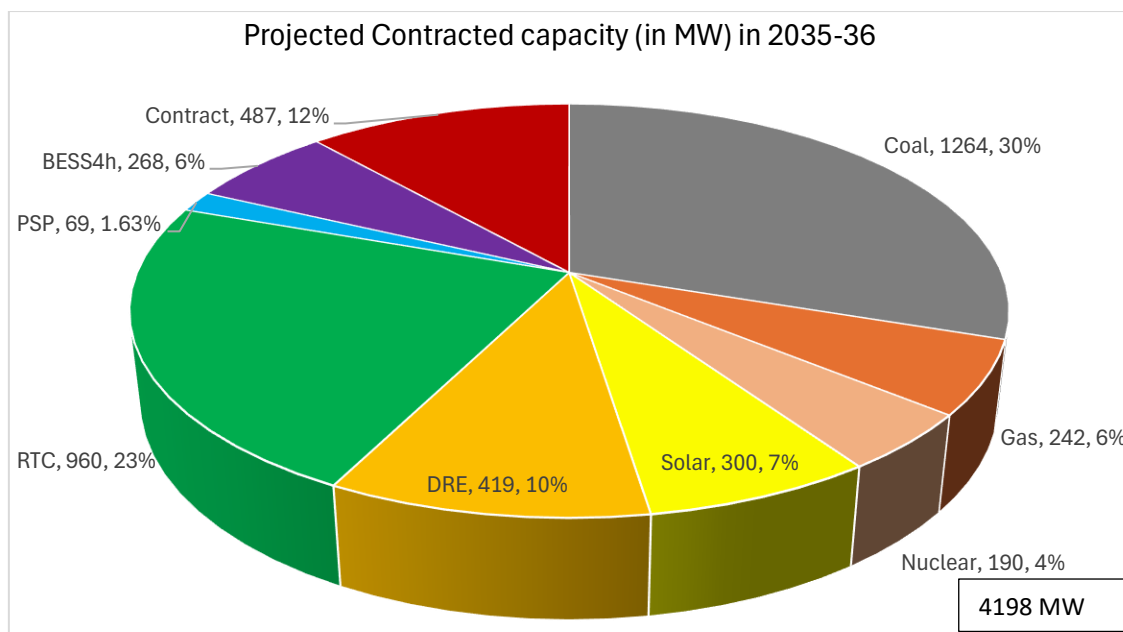


Figure 8: Contracted Capacity Mix in 2035-36

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

As per the study, the UT/state likely needs to contract the following capacities (planned and additional) every year till 2035-36 to meet its demand reliably and compliance with RCO as shown in Table 7.

Table 7: Year-wise Capacity Addition/Retirement (in MW)

Year	PSP(6h) Additional	BESS 4h Additional	Solar Planned	DRE Planned	DRE Additional	RE-RTC Planned	RE-RTC Additional
2025-26	0	0	0	115	0	0	0
2026-27	0	0	0	9	27	0	0
2027-28	0	0	100	9	38	300	0
2028-29	0	79	200	10	40	300	0
2029-30	64	0	0	10	44	0	0
2030-31	5	0	0	12	2	0	0
2031-32	0	14	0	12	3	0	85
2032-33	0	43	0	13	2	0	56
2033-34	0	47	0	14	3	0	58
2034-35	0	51	0	10	8	0	63
2035-36	0	34	0	10	10	0	98

The projected year-wise capacity mix is given in Figure 9. It can be observed that share of thermal capacity in entire mix is anticipated to reduce substantially from around 88% at present to less than 40% by 2035-36 with likely addition of RE resources like RE-RTC, Solar PV, DRE etc. in future.

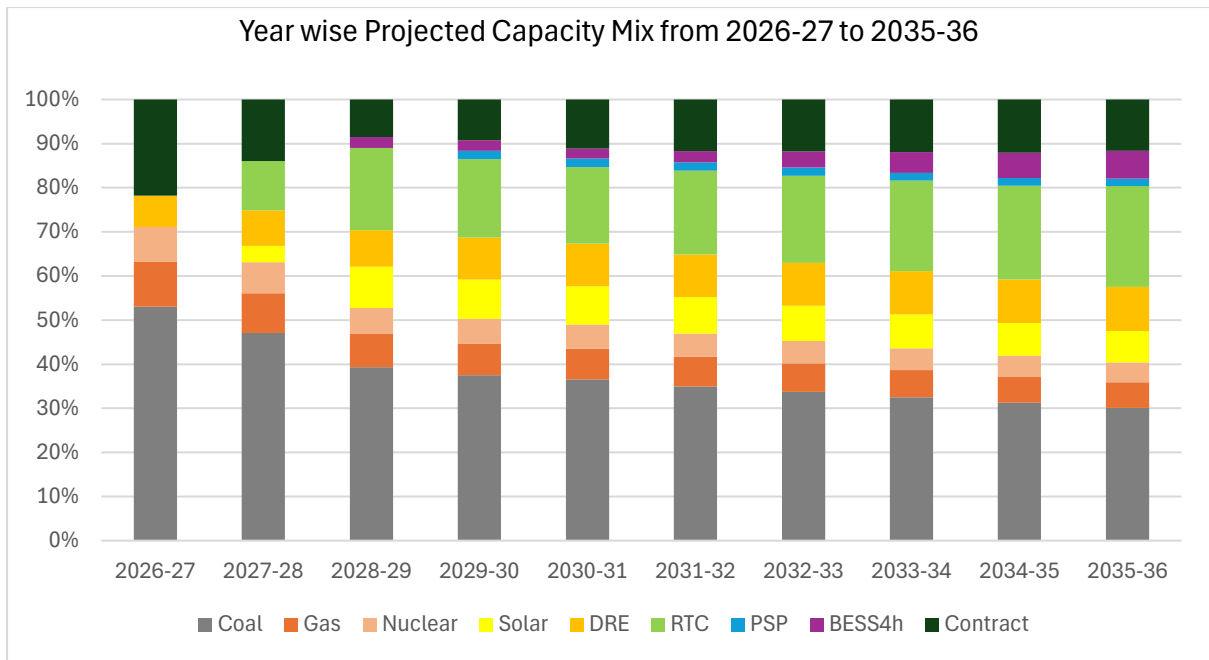


Figure 9: Year-wise capacity mix (in %)

Figure 10 shows year wise gross generation which undergoes a structural transition over the study period. Overall Fossil based generation in the generation mix declines with coal remaining the largest single source in absolute terms but its share in generation as well as in capacity mix declines sharply. Growth is primarily driven by RE-RTC resources. The contribution of Solar, BESS, and DRE also grows gradually in the generation mix with planned capacity addition in future. Overall, the system evolves from a coal-dominated portfolio to a diversified mix anchored by renewable (RTC) capacity.

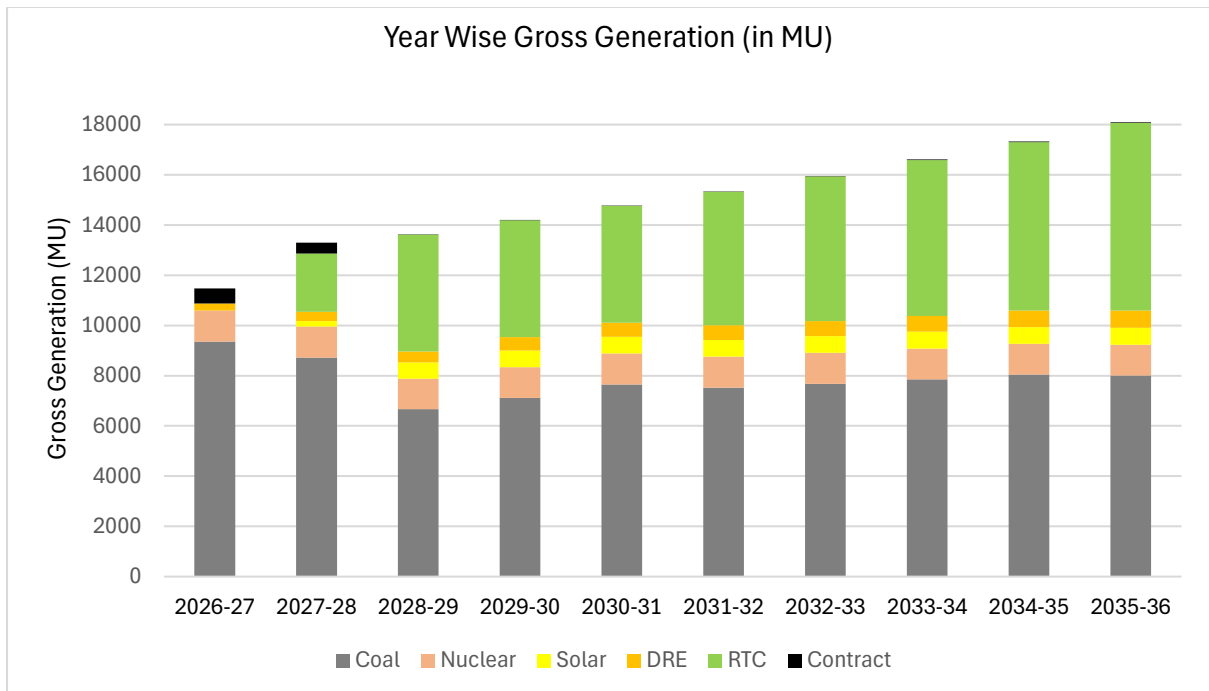


Figure 10: Year-wise projected Gross generation (in MU)

6.2 Surplus Capacity

Generally, surplus capacity is available with the utilities due to variation in electricity demand, RE availability, etc. The pattern of surplus capacities has been observed, as shown in Figure 12. From the figure below which shows MW surplus only during non-solar hours (Non-solar hours defined from 7 PM to 6 AM), it is observed that DNH&DD is expected to have a surplus coal capacity ranging up to 99 MW in FY 2031-32 in the study period during non-solar hours. Additionally, Gas based capacity of 242 MW is also available which is not being used for meeting electricity demand due to high variable cost of generation. This overall surplus capacity may be banked or shared with other states or UTs whose demand profile complements that of DNH&DD.

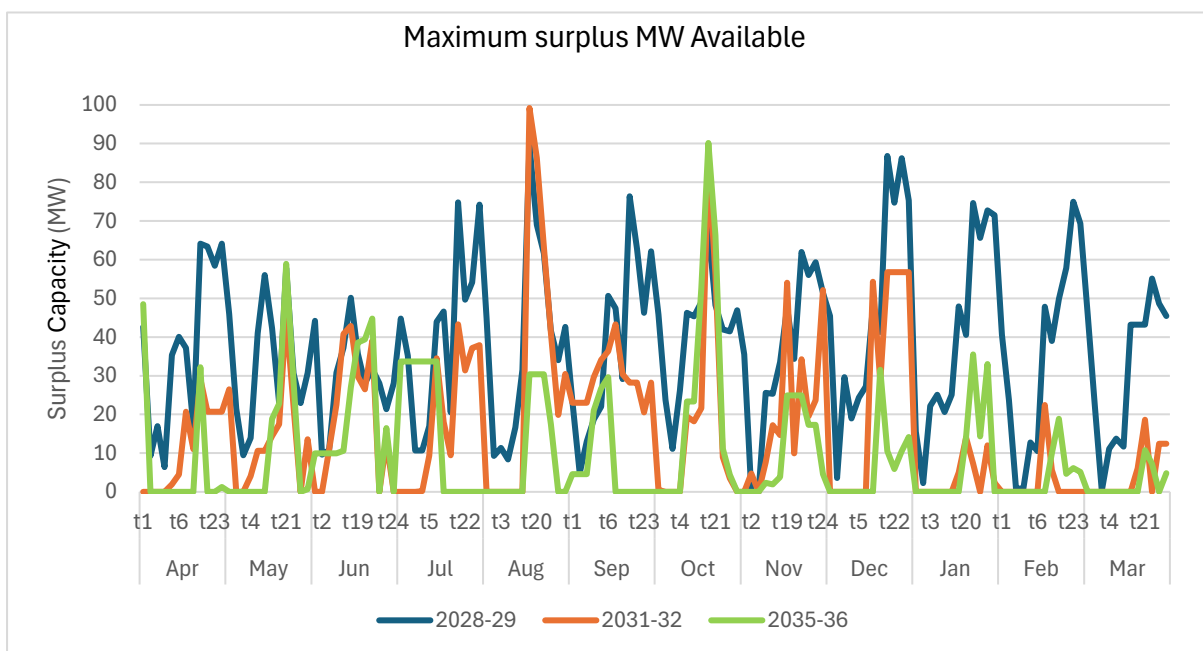


Figure 12: Maximum Surplus MW Available vs Time of the Day (TOD) in Non-Solar hours

7.0 Conclusions

Based on the Resource Adequacy studies of DNH&DD up to the year 2035-36, the following conclusions may be drawn:

1. The study has considered electrical energy and peak demand requirement projections as per the projections furnished by DNH&DD, which envisages that the annual energy requirement of the Union Territory is likely to grow at a CAGR of 4.1 % while the peak electricity demand is likely to grow at a CAGR of 4.7 % for the period of 2024-25 to 2035-36. The study has been done based on the hourly electricity demand pattern of the year 2024-25. It has been observed that the peak demand season is typically during the month of February followed by December, with peak demand occurring during non-solar hours.

2. DNH&DD, with its existing and planned capacity additions, is unlikely to meet its RCO obligation. However, the study has assessed the requirement to fulfil its Renewable Energy Consumption Obligation.
3. Based on the study, the likely total projected contracted capacity for the year 2035-36 is around 4198 MW, which consists of 1264 MW from coal, 242 MW from gas, 190 MW from Nuclear, 300 MW from solar, 419 MW from DRE, 960 MW from RTC(RE) source, 268 MW/1072 MWh from Storage (BESS 4Hr), 69 MW from PSP and 487 MW from contracts. This capacity shall be able to meet the projected demand with prescribed reliability criteria and to comply with the stipulated Renewable Energy Consumption Obligation (RCO) targets.
4. For the UT to fulfil its Renewable Energy Consumption Obligation, in addition to the existing and already planned contracts, needs to tie up approximately 177 MW of DRE-based capacity, 360 MW of RE-RTC-based capacity, 268 MW/1072 MWh of BESS capacity and 69 MW/414 MWh of PSP by 2035-36. The projected capacity and generation mix outlined in the report meet the Union Territory's RCO requirements by 2035-36.
5. As per studies, the DNH&DD is expected to have a surplus of coal-based capacity ranging up to 99 MW during the study period in non-solar hours and gas-based capacity of 242 MW. This surplus capacity may be banked or shared with other states/UTs whose demand profile complements that of DNH&DD.
6. The Planning Reserve Margin (PRM) for DNH&DD has been assessed at ~7.5 %. Further, the study indicates year-wise short-term/medium-term/bilateral requirements, inclusive of the PRM capacity to meet the demand optimally.
7. Timely commissioning of planned capacities is critical for ensuring that the Union Territory meets its projected peak electricity demand and electrical energy requirements reliably. Any deviation from the planned schedule may lead to resource shortfalls and could significantly increase the cost of reliably meeting the state's/UT's power demand.
8. While adhering to resource adequacy guidelines, environmental considerations must be systematically integrated into the planning and contracting of new capacity additions to ensure sustainable and responsible system development.
9. LT-DRAP to be prepared on an annual rolling basis and the long-term projections for contracted capacities should be revised periodically with improved visibility of demand forecast, load pattern, projects timelines, market conditions for renewables and storage-technology developments.

Details of upcoming capacities/retirements considered in the study

Sl. No.	Technology	Expected CoD	Tentative share (MW)
1	Solar	2027-28	100
		2028-29	200
2	RE-RTC	2027-28	300
		2028-29	300
3	DRE	2025-26	115
		2026-27	9
		2027-28	9
		2028-29	10
		2029-30	10
		2030-31	12
		2031-32	12
		2032-33	13
		2033-34	14
		2034-35	10
		2035-36	10

Assumption for Resource Adequacy Studies

1. Electricity Demand & peak requirement: As per information furnished by DNH&DD.
2. Demand Profile: Based on the 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 the National Electricity Plan.

RE CUF considered

RTC	Solar	DRE
90%	26-27%	18-19%

Technical Parameters

Technology	Type	Availability (%)	Ramping (%/min)	Min. Technical. (%)	
Coal/ Lignite	Existing/Planned	85	1	55	
	Candidate	88	1	55	
Gas	Existing	90	5	40	
Nuclear	Existing/Planned	68	Const. Load	-	
Solar	Existing/Planned	As per the available hourly generation profile	-	-	
	Candidate		-	-	
RTC	Existing/Planned		-	-	
	Candidate		-	-	
Pumped storage Projects	Existing/Planned		95	10	-
	Candidate			10	-

Technology	Type	Availability (%)	Ramping (%/min)	Min. Technical. (%)
Battery Energy Storage System	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
Nuclear	Existing/ Planned	2777	2777	10
	Candidate	2777	2777	10
Biomass	Existing/ Planned	4200	4450	8
	Candidate	4200	4450	8
Hydro	Existing/ Planned	-	-	0.7
	Candidate	-	-	0.7
Pumped Storage Projects	Existing/ Planned	-	-	Round Trip Efficiency 80 %
	Candidate	-	-	
Battery Energy Storage System	Candidate	-	-	Round Trip Efficiency 88%

Transmission Parameters

A single -node system has been considered for study, with all generating units and demand connected to the single node of DNHDD. No Transmission bottleneck in the form of the Interstate ATC limit has been considered in the study.

Financial Parameters

The following cost parameters have been assumed:

Resource	Capex (in ₹/MW)	O&M Fixed Cost (in ₹/MW)	Construction Time (in years)	Amortization /Lifetime (in years)
Coal	12 Cr	30 Lakh	4	25
Solar*	4.5 Cr to 4 Cr	1 % of Capex	1	25
Wind	7.5 Cr	1% of Capex	2	25
Battery Energy Storage System (4-Hour)	5 Cr (2025-26) to 3 Cr(2035-36)	6 Lakh	1	15
PSP (6 Hour)	6 Cr	30 Lakh	4	40

RE-RTC	35 Cr	1 Lakh	1	25
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*Solar cost is assumed to reduce from INR 4.5 Cr/MW in 2025-26 to INR 4.1 Cr/MW in 2035-36