LONG TERM POWER SYSTEM DEVELOPMENT PLAN (LTPSDP) (2027-2046)

INTERIM REPORT (2027-2029)

National System Operator

Contents

Executive Summary

This Interim Report for the Long Term Power System Development Plan (LTPSDP) 2027-2046 has been prepared to address the urgent generation capacity requirements for the period 2027-2029 until the completion of the complete LTPSDP. Given the lengthy preparation and approval process of the LTPSDP, an Interim report is prepared to address urgent capacity needs for 2027–2029, enabling timely procurement decisions to maintain system reliability and cost effective operation until the LTPSDP is prepared. It is to be noted the conditions in the prevailing Long Term Generation Expansion Plan (LTGEP) 2025-2044 has now deviated due to higher electricity demand growth, delays in committed generation projects with increase in rooftop solar penetration resulting in additional system operational challenges.

The updated demand forecast projects net generation requirements to increase from 20,549 GWh in 2027 to 22,616 GWh in 2029, while this was 19,630 GWh in 2027 and 21,750 GWh in 2029 in the LTGEP 2025-2044. Peak demand is expected to rise from 3,342 MW in 2027 to 3,686 MW in 2029 while this was 3,027 MW in 2027 and 3,362 MW in 2029 in the LTGEP 2025-2044. Recent system trends also indicate increasing night peak demand and off peak (22:00 to 06:00) energy consumption. Renewable energy implementation has progressed with deviations to the planned values, with rooftop solar additions exceeding planned targets while wind power development has experienced delays due to environmental, land, transmission and financing constraints. Accordingly, renewable energy and Battery Energy Storage System (BESS) implementation schedules were reassessed for the interim study period.

The planning studies were carried out using internationally recognized optimization and simulation software tools developed by PSR, namely SDDP, OPTGEN and TSL. These tools enabled detailed stochastic simulation of hydrothermal system operations and least cost optimization of future capacity additions while considering renewable energy variability, hydrological uncertainty, operational constraints and hourly demand patterns.

The analysis indicates that, during the 2027–2029 period, new capacity additions will be largely limited to solar generation and BESS primarily due to transmission network constraints that cannot be overcome in next three years and project lead time. Within the considered planning horizon, no additional thermal generation beyond the already committed projects is required. By 2029, total installed system capacity is projected to reach approximately 10,924 MW, with renewable energy contributing around 68% of total annual generation. The capacity growth of solar power additions is illustrated in figure E1.

Battery energy storage systems are expected to play a critical role in absorbing excess renewable energy during day time and supplying energy during night peak demand periods. The expected deployment of Battery energy storage systems is illustrated in figure E2.

The studies further highlight emerging operational challenges associated with high renewable energy penetration. Increasing solar generation is expected to significantly increase net load ramping requirements and reduce system synchronous inertia levels, creating potential frequency related stability risks. Accordingly, the report emphasizes the urgent need for Renewable Energy Management Systems (REMS), modernization of SCADA/EMS systems, deployment of synchronous condensers and implementation of Grid Forming BESS technologies to maintain reliable and secure system operation.

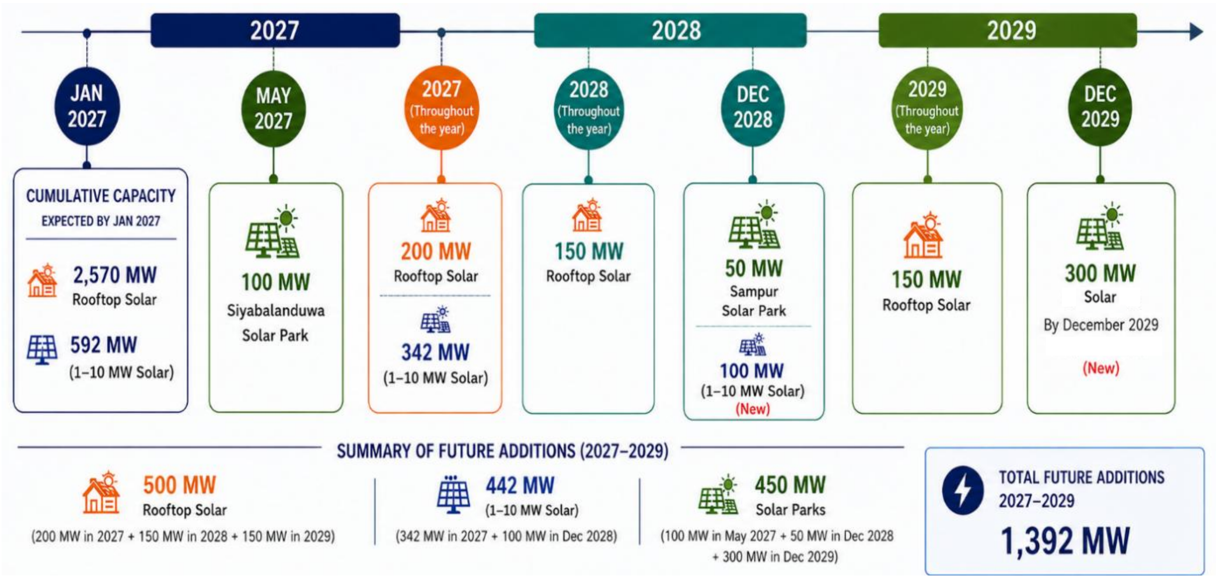


Figure E1: Solar Power Capacity Additions 2027-2029

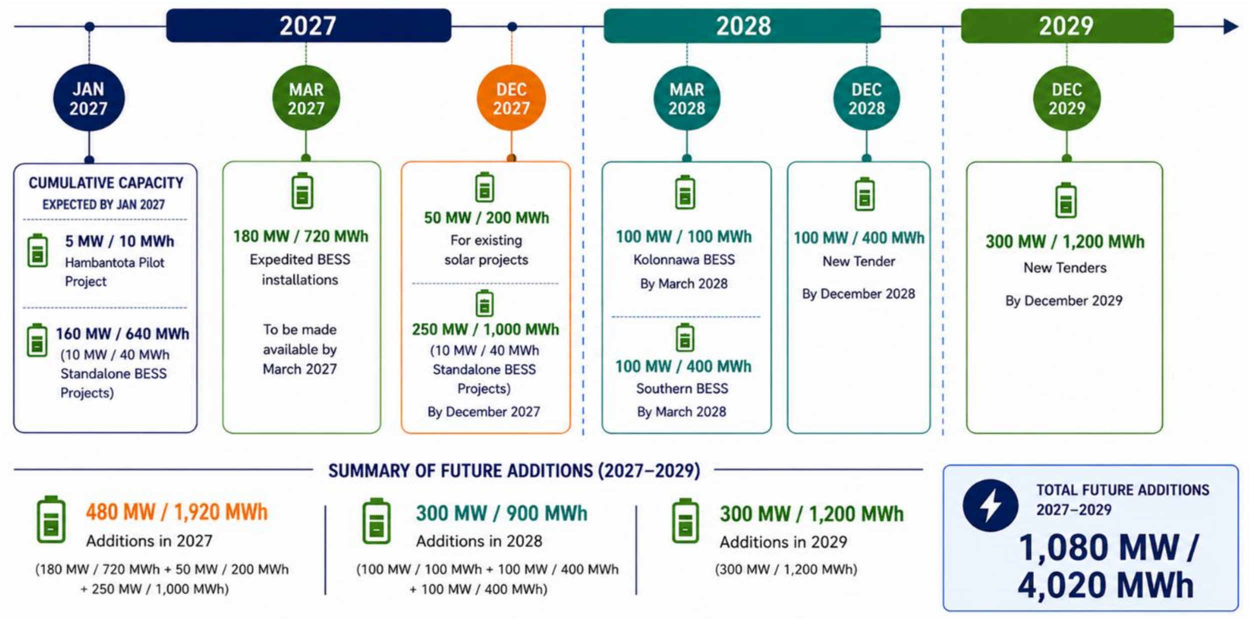


Figure E2: Battery Energy Storage System Additions 2027-2029

The development of transmission infrastructure required to connect renewable energy zones, particularly high potential wind resource areas, has been progressing slowly. Early action is therefore required to accelerate the government approvals, land acquisition and clearance processes and financing arrangements with coordinated action among relevant institutions.

To better align electricity demand with the evolving generation mix, demand side management measures including Time of Use (TOU) and time of week tariff structures should be implemented to encourage load shifting from high demand periods to periods of surplus generation. These measures may include incentivizing industrial and commercial operations, as well as electric vehicle charging during daytime hours of Sundays.

Although solar power and BESS deployments have exceeded the levels anticipated in the previous plan, delays in the implementation of wind power projects have constrained wind capacity expansion, leading to lower additions. Table E1 and Figure E3 illustrates the deviations in capacity additions compared with the LTGEP 2025–2044.

Table E1: Comparison of Cumulative Generation and Storage Capacity

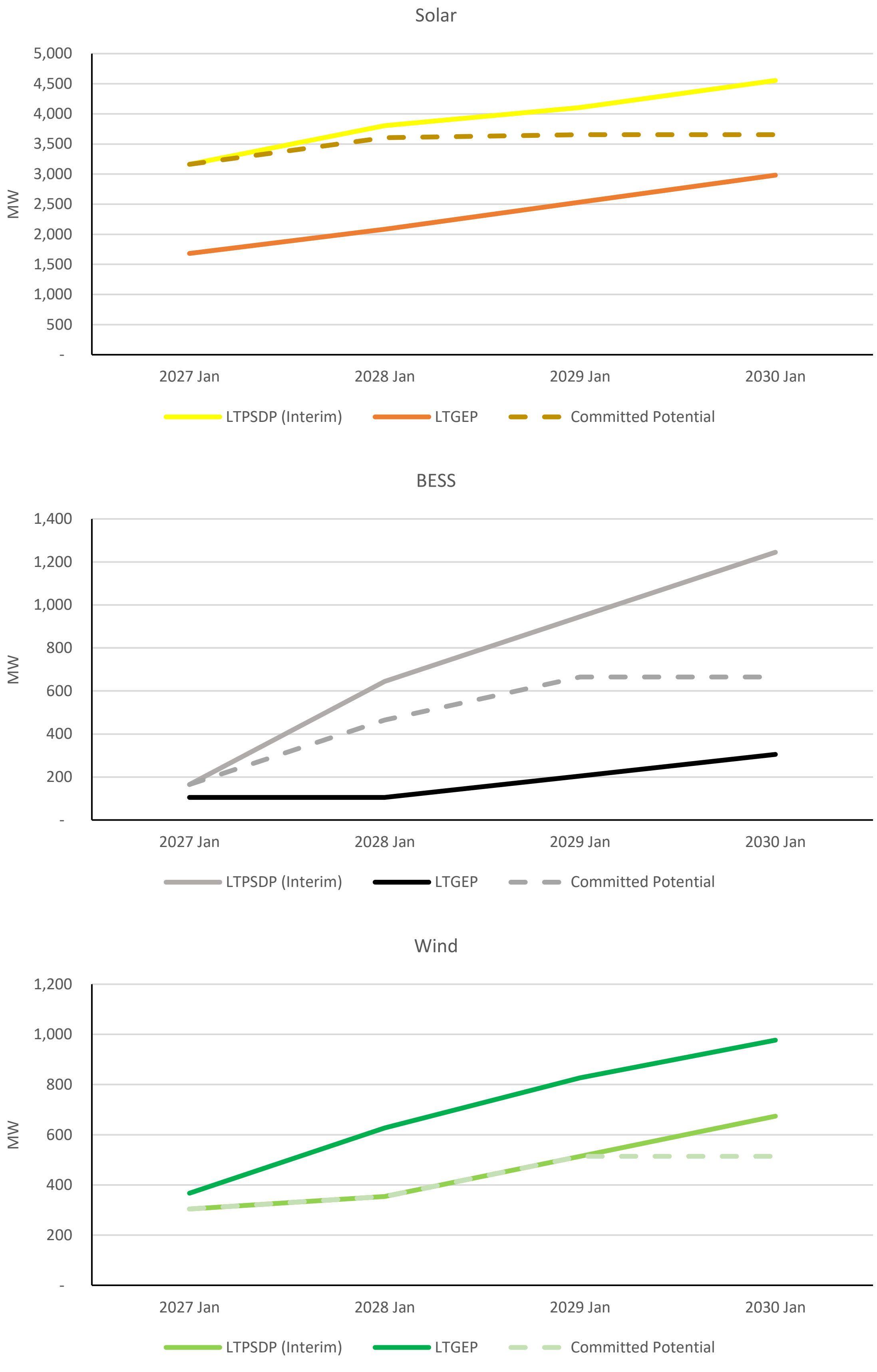
	Wind		Solar		BESS	
	LTGEP 2025-2044	LTPSDP-Interim	LTGEP 2025-2044	LTPSDP-Interim	LTGEP 2025-2044	LTPSDP-Interim
2027	627 MW	354 MW	2,082 MW	3,804 MW	105 MW/110 MWh	645 MW/ 2,570 MWh
2028	827 MW	514 MW	2,532 MW	4,104 MW	205 MW/510 MWh	945 MW/ 3,470 MWh
2029	977 MW	674 MW	2,982 MW	4,554 MW	305 MW/910 MWh	1,245 MW/ 4,670 MWh

In Figure E3 committed potential indicate the cumulative of already developed, procurement initiated and construction ongoing projects. It should be noted that committed projects of solar power and BESS development has well exceeded planned capacities in LTGEP 2025-2044. However, the interim report is proposing a substantial increase for the Solar and BESS capacity additions, to be installed by 2029 compared to LTGEP 2025-2044 and currently committed potential. By the end of 2029, the interim report enables provision for absorption of an additional 1,572 MW of solar PV capacity and 940 MW of BESS capacity relative to the LTGEP 2025–2044. As the wind power has not exceeded the LTGEP 2025-2044 target, the interim report proposes a more realistic target for 2027-2029 taking into account the current status of wind power development.

The report also elaborates the contingency analysis focusing on impacts and solutions for risk events on dry hydro conditions, outage of major power plant and further increase in electricity demand. The potential capacity requirement to manage these risk events can be met by advancing the capacities identified in the Interim Report for the 2028–2029 period, considering the probability of occurrence of the identified risk events.

The report recommends timely implementation of committed generation, renewable energy, transmission and storage projects together with appropriate system stability enhancement measures to support Sri Lanka's transition toward a secure and reliable power system.

It is to be noted that this Interim Report contains preliminary findings of the Long Term Power System Planning Study and has been issued to support urgent near term decision making. Although certain detailed operational results, including dispatch and renewable energy curtailment levels, may undergo minor adjustments upon completion of the full study, the overall conclusions regarding the required capacity additions for the period 2027-2029 are expected to remain unchanged.



Note: Committed potential indicate the cumulative of already developed, procurement initiated and construction ongoing projects.

Figure E3: Comparison of Cumulative Capacity of Solar, Wind and BESS

1. Background

The Long Term Generation Expansion Plan (LTGEP) 2025–2044, was prepared by the Ceylon Electricity Board under the provisions of the Sri Lanka Electricity Act No. 20 of 2009 (as amended) and subsequently approved by the Public Utilities Commission of Sri Lanka. It presently serves as the governing generation expansion and procurement planning document for future power plant additions in Sri Lanka.

However, several conditions and assumptions considered in that LTGEP have since changed. These include variations in electricity demand growth, delays in the implementation of committed generation projects and changes in economic conditions. In addition, recent operational trends in the power system, including increased electricity demand, changes in demand patterns and increased integration of solar power additions than previously planned, have created new planning challenges that require reassessment.

Under the Sri Lanka Electricity Act No. 36 of 2024 (as amended), the National System Operator is required to prepare the Long Term Power System Development Plan (LTPSDP) within one year from the appointment date of 9th March 2026. Prior to the appointment date, Ceylon Electricity Board initiated data collection for the next long term planning cycle and submitted the necessary input data for planning studies to the regulator for confirmation on 6th February 2026. Accordingly, the LTPSDP 2027–2046 is presently under preparation by the National System Operator, with necessary recommendations on input data from the Public Utilities Commission of Sri Lanka.

The preparation of the LTPSDP requires detailed power system studies, demand forecasting, generation expansion modelling, transmission planning studies, reliability assessments and comprehensive engineering evaluations which are inherently time intensive. In addition to the lengthy plan preparation times the approval process requires approximately further 6 months with the necessary recommendations from regulator ministry review and subsequent cabinet approval. However, considering the urgency associated with identifying and initiating procurement requirements for the period 2027–2029, arising from deviations from the approved LTGEP 2025–2044, an interim report is required to address the immediate capacity requirements of the power system until the completion and approval of the LTPSDP. The interim report will support timely decisions to initiate the immediate capacity procurement in order to maintain adequate reserve margins, ensure system reliability and reduce costs during the transition period.

2. Assumptions and Deviations from Previous Plan (LTGEP 2025-2044)

2.1 Demand Forecast

The electricity demand forecast for the period 2027–2051 was developed as an integral component of the preparation of the Long Term Power System Development Plan (LTPSDP) 2027–2046. The same demand forecast has been adopted for the purpose of this interim report in order to maintain consistency with the ongoing LTPSDP studies.

The demand forecast methodology comprises a combination of medium-term and long-term econometric forecasting approaches. For the medium-term forecast, a time-series modelling approach with monthly time resolution was utilized to evaluate variations in electricity demand arising from end-user tariff adjustments, weather conditions, seasonal variations and other relevant influencing factors. In addition, major development projects and transport electrification initiatives, including electric vehicle adoption, were appropriately incorporated into the forecast.

Recent demand trends observed in the power system include notable growth in night peak demand and an increase in off peak energy consumption, primarily driven by changes in consumer behavioural patterns. Accordingly, the electricity demand forecast considered for the covering the period 2027–2029 is presented in table 1.

Table 1: Demand Forecast

Year	Demand[1]	Net Loss[2]	Net Generation	Day Peak Demand	Night Peak Demand
	GWh	%	GWh	MW	MW
2027	18,853	8.25	20,549	3,342	3,327
2028	19,860	8.00	21,587	3,514	3,482
2029	20,920	7.50	22,616	3,686	3,634

[1] In the process of developing the demand forecast, all embedded generation that is not metered real time at NSCC is evaluated to reflect the actual demand and generation.
[2] Net losses include losses at the Transmission & Distribution levels and excludes Generation (including auxiliary consumption) losses. Loss forecast will vary depending on the renewable thermal generation mix of the future.

Comparison of demand forecast with LTGEP 2025-2044 is shown in table 2.

Table 2: Comparison with Demand Forecast 2025-2049

<table>
<tr><th rowspan="2">Year</th><th colspan="3">Generation (GWh)</th><th colspan="3">Peak (MW)</th></tr>
<tr><th>Demand Forecast 2027-2051 (A)</th><th>Demand Forecast 2025-2049 (B)</th><th>Difference (A-B)</th><th>Demand Forecast 2027-2051 (A)</th><th>Demand Forecast 2025-2049 (B)</th><th>Difference (A-B)</th></tr>
<tr><td>2027</td><td>20,549</td><td>19,630</td><td>918</td><td>3,342</td><td>3,027</td><td>315</td></tr>
<tr><td>2028</td><td>21,587</td><td>20,662</td><td>925</td><td>3,514</td><td>3,190</td><td>325</td></tr>
<tr><td>2029</td><td>22,616</td><td>21,750</td><td>866</td><td>3,686</td><td>3,362</td><td>324</td></tr>
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2.2 Renewable Power Plant and Storage Implementation

When considering the implementation status of the planned power plants under the LTGEP 2025–2044, it was observed that solar power capacity has exceeded the planned targets, primarily due to the significant expansion of rooftop solar installations. In contrast, the development of other renewable energy sources, particularly wind power, has not progressed as anticipated owing to site specific environmental, land and social constraints, as well as delays associated with funding limitations for transmission infrastructure development. Accordingly, the probable renewable energy capacity additions were reassessed by considering committed projects of signed Standard Power Purchase Agreements , signed Power Purchase Agreements, pending projects currently under the tendering process and the projected growth of rooftop solar installations.

In addition, considering factors such as the rooftop solar capacity additions exceeding the planned levels in the LTGEP 2025–2044 and the increase in night peak demand compared to the forecasted values, the implementation of the battery energy storage system capacities identified in the LTGEP 2025–2044 up to 2033 was advanced with the approval of the Public Utilities Commission of Sri Lanka. Accordingly, cumulative renewable energy and storage capacity expected as at 01.01.2027 including the projects expected to realise during 2026 is given in table 3.

Table 3: Expected Cumulative Renewable and Storage Capacities as at 01.01.2027

Source	Cumulative Capacity (MW)
Solar	3,162
Wind	304
Mini hydro	470
Biomass	70
BESS	165

Committed renewable energy and storage capacities considered for the period 2027-2029 are given table 4.

Table 4: Committed Renewable and Storage Capacities from LTGEP 2025-2044

Year	Capacity Addition (MW)					
	Major Hydro	Solar	Wind	Mini hydro	Biomass	BESS
2027	Moragolla – 31	Siyambalanduwa 100 Other Solar* - 342	Mannar (Nadakuda) - 50	10	10	10 MW/ 40 MWh BESS tender- 250 MW Existing Gound Solar tender – 50 MW Other BESS** – 100 MW
2028		Sampur - 50	Mullikulam – 100 Other Wind* - 60			Kolonnawa BESS – 100 MW Siyambalanduwa BESS – 100 MW
2029		-	Kondachchi - 100 Mannar - 60			

**Other solar and wind includes projects under Feed in Tariff Scheme and PPA signing pending projects*
*** Other BESS includes the project advanced from LTGEP and implementation modality yet to be decided*

2.3 Thermal Power Plant Implementation

2.3.1 Existing and Committed Thermal Power Plants

The present installed capacity mix of thermal power plants and their respective fuel is given in table 5.

Table 5: Expected Cumulative Thermal Capacities as at 01.01.2027

Power Plant	Capacity (MW)	Fuel Type
Lakvijaya Coal Power Plant	810	Coal
Kelanitissa Combined Cycle 1	165	Naphtha
Kelanitissa Combined Cycle 2	163	Diesel
Sapugaskanda A	68	Furnace Oil
Sapugaskanda B	72	Furnace Oil
Uthuru Janani	27	Furnace Oil
Barge Mounted Power Plant	60	Furnace Oil
West Coast Combined Cycle	270	Furnace Oil
Sobadhanavi Combined Cycle	312	Diesel
Containerized Diesel Power Plants	50	Diesel

Expected implementation schedule of committed thermal power plants identified in LTGEP 2025-2044 is given in table 6.

Table 6: Planned Thermal Power Projects

	Thermal Capacity Additions as per LTGEP 2025-2044	Capacity (MW)	Commissioned Year considered for Interim report
2026	Gas Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)	235	Expected in 2028
2027	Steam Turbine of Second Natural Gas Combined Cycle Plant (Kerawalapitiya)	115	Expected in 2029
2028	IC Engine Power Plant - Natural Gas	200	Delayed beyond 2030 and to be reevaluated

Note: As identified in LTGEP 2025-2044 115 MW GT 7 power plant has been retired from operation by end of 2025 and Sapugaskanda Station A (68 MW), Sapugaskanda Station B (72 MW) and Barge Mounted Plant (62 MW) has been extended to operate until end of year 2030.

2.3.2 Fuel Prices

Fuel prices considered for the interim report of LTPSDP are based on economic basis excluding tax as shown in table 7. The cost values have been projected based on the future fuel price forecast of World Bank and the International Energy Agency.

Table 7: Fuel prices used for the study

	Coal US$/Mton	Diesel US$/bbl	Furnace Oil US$/bbl	Naphtha US$/bbl
Fuel Price	124.7	120.5	119.6	87.7

LTGEP 2025-2044 considers the availability of natural gas mid 2027. However, considering the delayed procurement for NG infrastructure, for this analysis, natural gas is assumed not to be available for the period from 2027-2029.

2.4 Development of Transmission Infrastructure

The following ongoing and committed transmission development projects are under various stages of development. These projects are designated as priority infrastructure initiatives that require coordinated institutional action to facilitate their timely implementation and commissioning. The expected completion years are based on the latest long term transmission development plan and latest project progress. The timeline may be subject to revision during project implementation, depending on project progress and any implementation related constraints.

1. Habarana – Veyangoda 220 kV Transmission Project (Expected Completion Year - 2027)

   Establishing a strategically important transmission corridor to strengthen the national grid, alleviate network congestion, facilitate the transfer of renewable energy from resource-rich regions to load centers and enhance overall system stability, reliability and operational flexibility.

2. Padukka – Horana 132 kV Transmission Line (Expected Completion Year -2027)

   Strengthening the transmission network in the Western Province by enhancing power transfer capability, improving supply reliability, supporting growing electricity demand in the region and facilitating the integration of distributed renewable energy generation into the national grid.

3. Construction of the Hambantota – Matara 132 kV Double-Circuit Transmission Line (Expected Completion Year -2028)

   Strengthening the transmission network in the Southern Province by enhancing power transfer capability of hydro generation to Matara, improving system reliability, facilitating the evacuation of renewable energy from the Southern and South-Eastern regions and supporting future electricity demand growth in the area.

4. Construction of the New Habarana – Kappalthurei 220 kV Transmission Line (Expected Completion Year -2029)

   Providing essential transmission connectivity for renewable energy projects in the North Eastern region and improving network flexibility.

5. Construction of the Kerawalapitiya Second Cable (Expected Completion Year -2027)

   Enhancing transmission reliability and operational security within the Western Province while supporting increased renewable energy integration.

6. Construction of the Sampur – Kappalthurei 220 kV Transmission Line (Expected Completion Year -2028)

   Supporting renewable energy development in the Eastern Province and strengthening regional transmission infrastructure.

7. Construction of Victoria-Rantambe 220kV Transmission Line (Expected Completion Year -2027)

8. All the ongoing projects under PSRSIEP and NTDND&EIP-I (Expected Completion Year -2028/2029)

2.5 Candidate Technologies

Renewable, thermal and storage candidate technologies that can be commissioned within a three year period, considering lead times, were included in this study. Renewable energy technologies include solar, wind, mini hydro and biomass which are variable and seasonal in nature. Thermal technologies comprise gas turbine and internal combustion (IC) engine plants, which offer dispatchable and flexible generation to meet system demand and provide backup during periods of low renewable output. BESS is considered as a storage technology, which is used to store excess renewable energy and supply it during high demand periods, thereby enhancing system flexibility, reliability and renewable energy integration. Detailed characteristics and assumptions for each technology are provided in Annex 1.

2.6 Other Assumptions

Other key assumptions adopted in the study include a discount rate of 8%, which is applied in the economic evaluation of candidate generation and storage options to reflect the time value of money.

In addition, a reserve margin criterion ranging from 2.5% to 20% is considered to ensure adequate system reliability as published in Gazette Extraordinary No. 2109/28 dated 2019-02-08.

3. Planning Tools and Methodology

3.1 Planning Software Tools

The studies were carried out using internationally recognized optimization and simulation tools developed by PSR to ensure a comprehensive and technically robust assessment of immediate requirement for future power system development. The primary software platforms used were Stochastic Dual Dynamic Programming (SDDP), OPTGEN and Time Series Lab (TSL).

SDDP was employed as the main hydrothermal operation planning model to simulate the operation of the Sri Lankan power system under stochastic hydrological and renewable energy conditions. The model incorporates detailed representations of hydro reservoirs and cascades, thermal generating units, renewable energy resources, energy storage systems, operational constraints and hourly demand variations. Historical inflow data, renewable resource data and probabilistic scenarios are used to determine least cost operating policies while capturing uncertainties associated with hydro inflows and variable renewable energy generation.

OPTGEN, integrated with the SDDP dispatch module, was used for optimization process. The software applies advanced mixed integer optimization techniques to identify the optimal sizing and commissioning schedule of capacity expansions. To improve the representation of renewable energy uncertainty and variability, TSL software was utilized to generate probabilistic wind, solar and hydro inflow scenarios using satellite based resource data. This enabled the modelling framework to capture seasonal variations, intermittency and spatial correlations among renewable resources and hydrological conditions, thereby improving the reliability of planning studies.

3.2 Planning Methodology

The planning methodology adopted for the study combines stochastic operational simulation with least-cost capacity expansion optimization to evaluate future generation development options for the period 2027-2029. However, the optimization was carried out for a horizon of 10 years. Detailed modelling was carried out for hydro, thermal, renewable and energy storage technologies considering their technical and operational characteristics.

Hydropower development was treated separately from the optimization process due to the limited availability of economically feasible large hydropower resources in Sri Lanka, as most viable large hydro projects have already been developed. At present, the Moragolla Hydropower Project is considered the only remaining major hydropower project and is therefore included in the plan as a committed project.

Renewable energy technologies including mini hydro, wind, solar photovoltaic and biomass were modelled using actual resource characteristics with explicit consideration of variability, uncertainty and seasonal generation patterns. Special emphasis was given to modelling wind and solar resources due to their increasing contribution to the future energy mix. Wind resource modelling was carried out considering five onshore wind locations and three offshore wind locations to capture geographical diversity and seasonal wind variations. Solar resource modelling included a wide spatial representation comprising approximately 23 rooftop solar regions, 40 ground mounted solar regions and 15 floating solar sites across the country. These detailed hourly renewable resource profiles were incorporated into the planning models to accurately represent generation variability, intermittency and regional resource diversity in the planning studies.

Battery energy storage systems were represented with detailed operational characteristics including charging and discharging efficiencies, state of charge limits and depth of discharge. These storage systems were primarily utilized to absorb excess renewable generation during low demand periods and support system flexibility through services such as ramping support, frequency regulation and renewable energy firming. Overall, the adopted methodology enabled detailed hourly simulation of future system operations, assessment of operational flexibility requirements, identification of renewable integration challenges and evaluation of least cost expansion strategies aligned with national renewable energy targets.

4. Results of the Analysis

Considering the updated demand forecast, project implementation delays, revised generation costs and latest system operating conditions, optimization was carried out for a period of 10 years study horizon to evaluate the adequacy of generation capacity and system reliability. Detailed analysis on operational capabilities considering 8760 hours for the year were conducted for the period from 2027-2029. The analysis focused on identifying potential capacity gaps, assessing the impact of delays in planned projects and determining the required capacity additions to maintain an adequate reserve margin while meeting forecasted electricity demand. The outcomes of the analysis provide guidance for short to medium term capacity planning and support timely decision making until the completion of the Long Term Power System Development Plan (LTPSDP). For the simulations, the existing and committed projects for the period 2027-2029, as described in Sections 2.2 and 2.3, were considered. Based on the demand forecast and committed project pipeline, the resulting capacity gaps were identified and suitable new generation additions were selected through optimization analysis. The results of the analysis are presented in this section.

4.1 Installed Capacity

Total installed capacity for the period 2027-2029 is comprised of the existing and committed power projects as described in section 2.2 and 2.3 as well as new capacity requirements in addition to the provisions of LTGEP 2025-2044 for the period as given in table 8.

Table 8: Additional Renewable Energy and Storage Capacity Requirements

	Solar	BESS
2027	200 MW Rooftop Solar	80 MW/320 MWh by March 2027
2028	150 MW Rooftop Solar 100 MW Grid Connected Solar by December 2028	100 MW/400 MWh by December 2028
2029	150 MW Rooftop Solar 300 MW Grid Connected Solar by December 2029	300 MW/1200 MWh by December 2029

Considering the project development lead time as well as the candidate technology costs, only solar PV and Battery Energy Storage Systems are selected in the optimization process as new capacities for the considered period. No new thermal projects are required within this time horizon.

Figure 1 shows the installed capacity available during the critical period of each year. The critical period of the Sri Lankan power system generally occurs during the beginning of the year, particularly under dry weather conditions. During this period, electricity demand increases due to higher ambient temperatures and increased cooling loads, while renewable energy availability except solar is comparatively lower. Hydro generation is limited due to reduced reservoir inflows and wind generation also remains minimal during this season. As a result, the system experiences reduced renewable energy contribution together with higher demand levels, making this period the most critical for maintaining system adequacy and reliability.

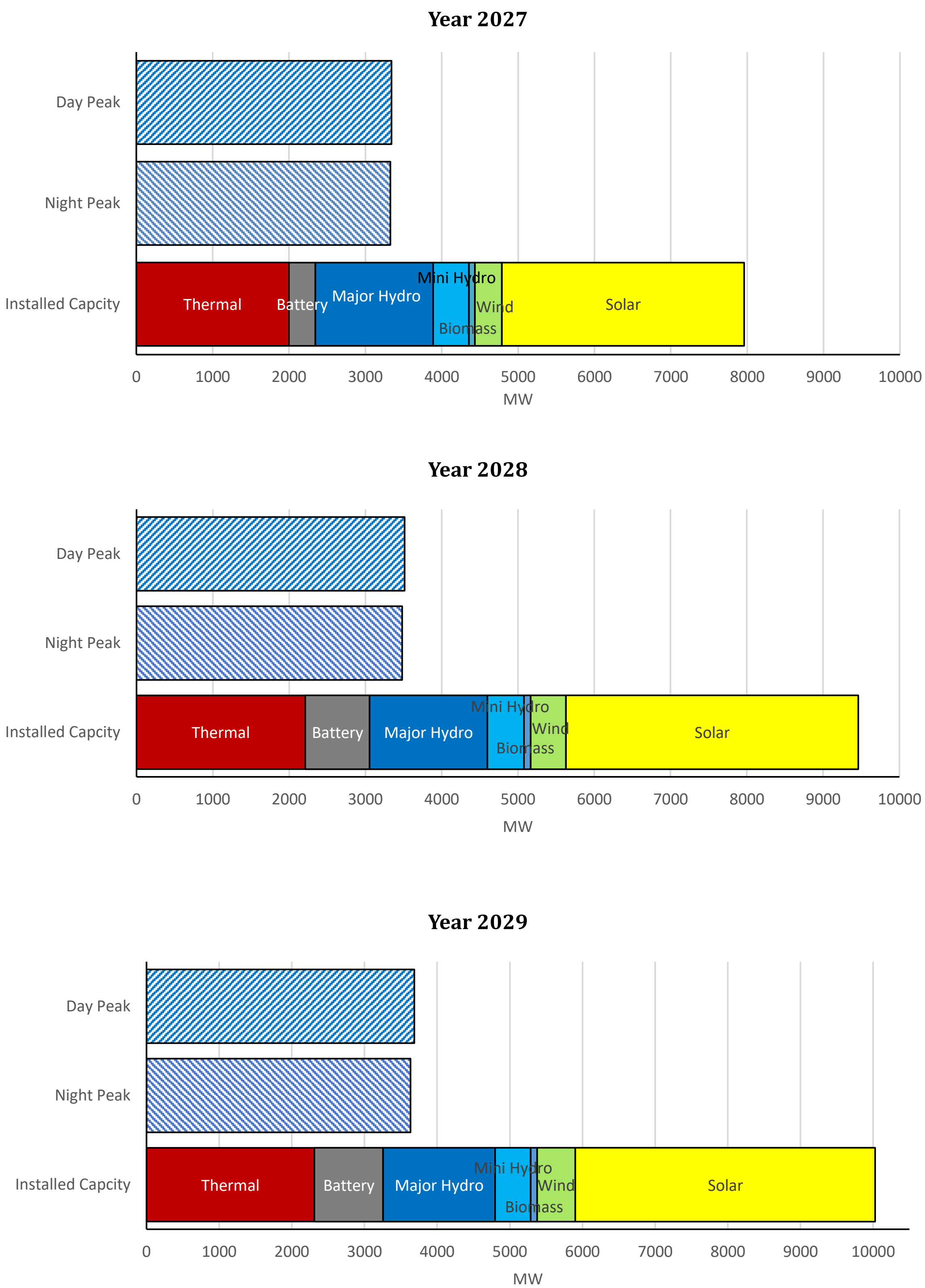


Figure 1: Installed Capacity in Critical Period for 2027, 2028 and 2029

Table 9 summarizes the category wise installed capacity for the period 2027-2029 at the end of each year.

Table 9: Installed Capacity Mix 2027-2029

	2027	2028	2029
Thermal	1,999	2,211	2,311
BESS	645	945	1,245
Major Hydro	1,543	1,543	1,543
Mini Hydro	470	480	490
Biomass	78	88	98
Wind	354	514	684
Solar	3,604	4,104	4,554
Total Installed Capacity	**8,693**	**9,885**	**10,925**
Critical Period Reserve Margin	**8%**	**19%**	**19%**

4.2 Generation Mix

The generation mix in year 2025, the estimated generation mix in year 2026 and the resulting generation mix for the period 2027–2029 are presented in Figure 2. The generation mix includes estimated self consumption from rooftop solar installations.

Although year 2025 experienced exceptionally high hydro inflows, lower hydro inflows are expected in year 2026. This results in a reduction in the share of renewable generation and a corresponding increase in thermal generation for year 2026. The generation mix for the study period 2027–2029 is presented assuming average hydro conditions.

In 2027, coal remains the second largest contributor to the energy mix after hydro generation. However, from 2028 onwards, solar generation surpasses coal and becomes the second largest energy source, contributing around 28% of the total generation mix. Overall, the renewable energy share increases significantly, reaching approximately 68% by 2029.

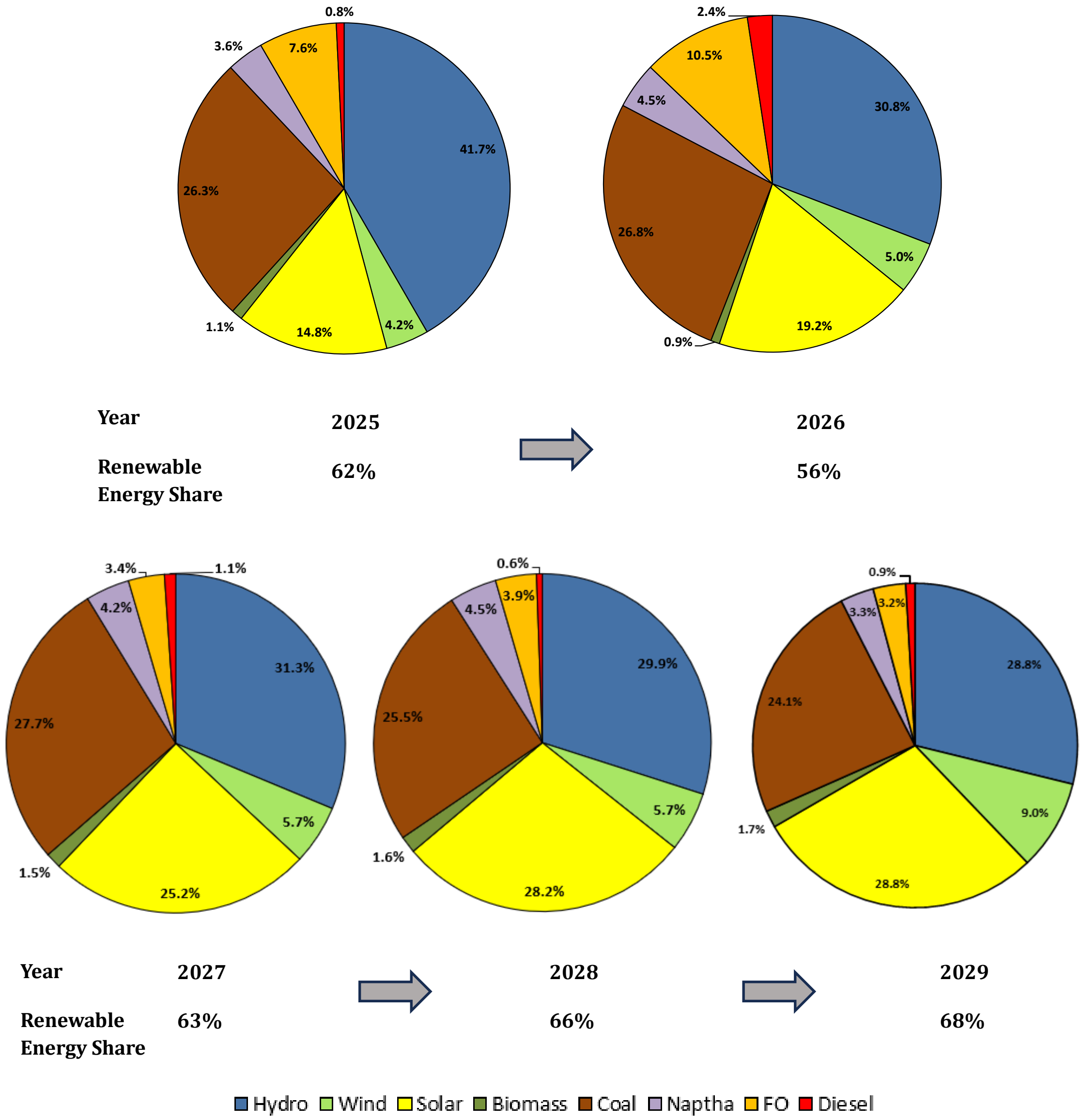


Figure 2: Generation Mix 2025-2029

4.3 Renewable Energy and Storage Utilization

The monthly distribution of renewable energy generation for the year 2028 is presented in figure 3, illustrating the contributions from major hydro, mini hydro, biomass, solar and wind resources across the year.

It can be observed that major hydro dominates the renewable energy mix throughout the year, with relatively stable generation and a noticeable increase during the latter part of the year, particularly from October to December. Solar energy remains the second largest contributor, showing a consistent seasonal pattern with comparatively higher generation during the beginning of the year and moderate variation across months.

Wind generation exhibits greater variability, with higher generation around midyear but declining during low wind seasons. Mini hydro and biomass contributions remain relatively small whereas mini hydro exhibits the same seasonality pattern as major hydro.

Overall, the figure highlights a clear seasonal dependency of wind, hydro and solar resources, The combined renewable energy mix shows higher total generation during months with stronger hydro inflows and wind conditions, particularly in the second half of the year. This seasonal pattern indicates that the critical period for years 2027-2029 typically occurs at the beginning of the year.

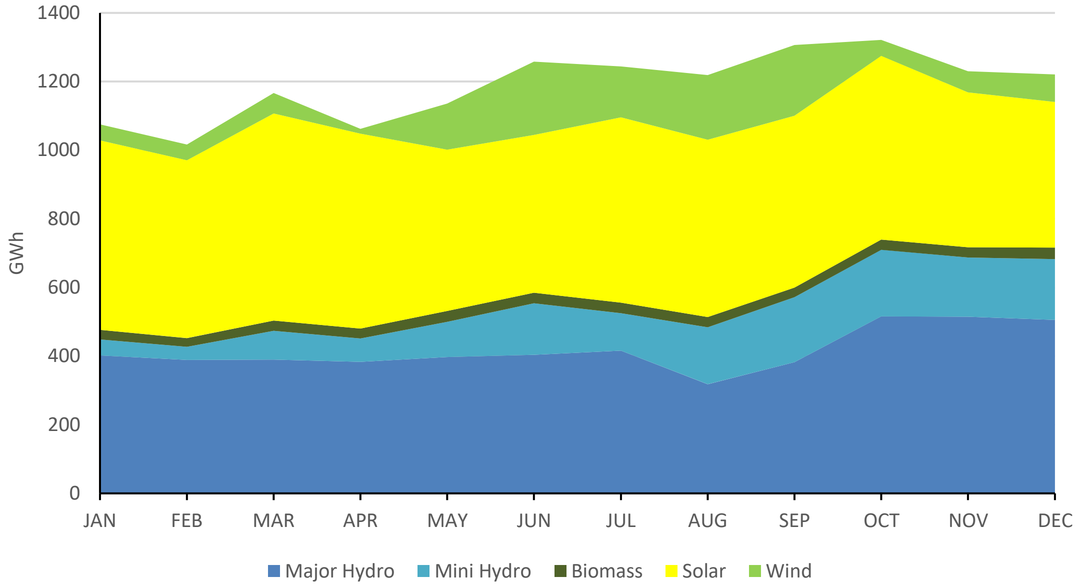


Figure 3: Monthly Distribution of Renewable Energy

The daily operation pattern of the battery energy storage systems in year 2028 is illustrated in figure 4. It could be observed that battery charging mainly occurs during daytime hours, while discharging takes place during the night peak period. In addition, a limited amount of charging occurs during off peak hours to cater to the morning peak demand, mainly during the high wind season months.

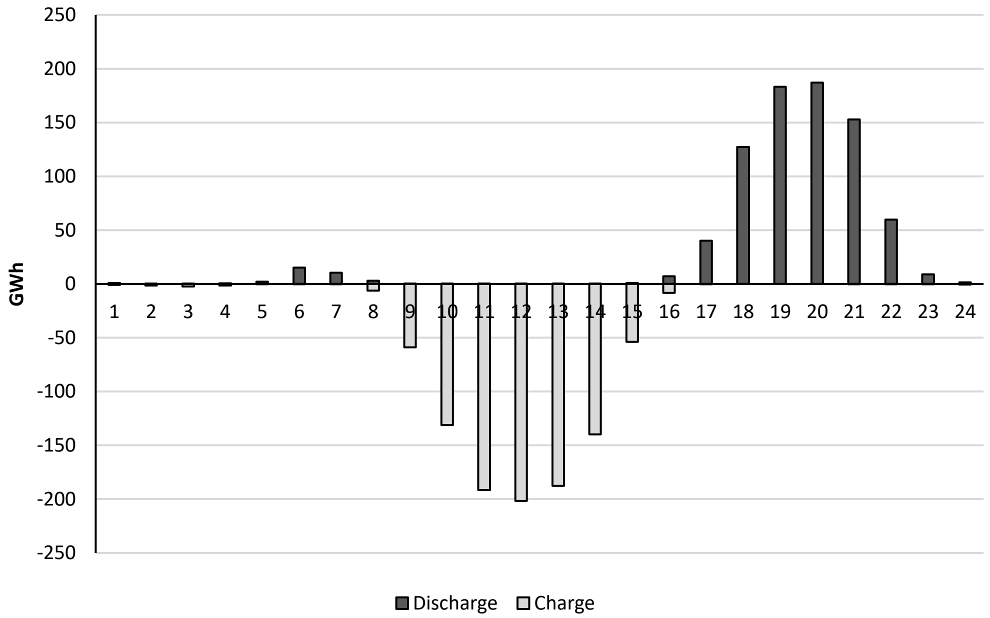


Figure 4: Hourly distribution of batteries

Similar operation pattern of renewable energy and battery energy storage is observed for the year 2027 and 2029.

4.4 Operation of Thermal Power Plants

Figure 5 shows the plant factors of each thermal power plant in the system during the year 2028. Coal power plants operate at high plant factors throughout the year, except during scheduled maintenance periods, reflecting their role as baseload generation sources. Kelanithissa combined cycle plant I operated from Naphtha plants exhibit the next highest plant factor, operating on merit order basis. Furnace oil plants operate at moderate plant factors, mainly serving mid merit and peak demand requirements. In contrast, diesel power plants operate at the lowest plant factors, indicating their limited utilization primarily for peak support during low renewable periods.

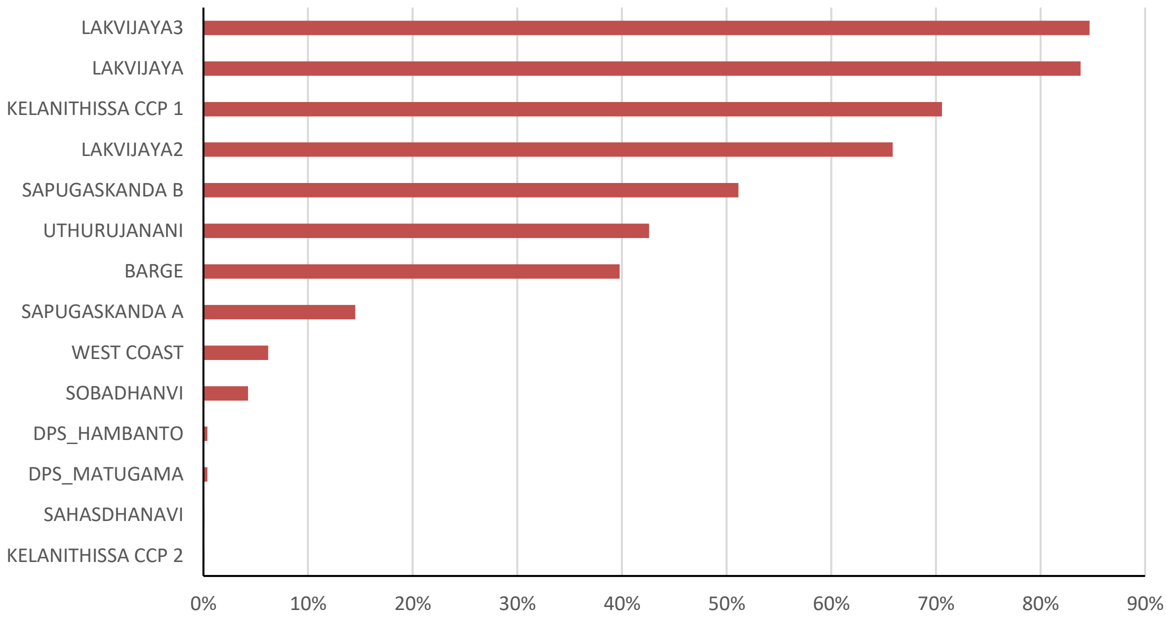


Figure 5: Plant Factors of Thermal Power Plants in 2028

Figure 6 illustrates how different thermal generation sources by fuel type are utilized over a typical 24 hour period for the year 2028. Coal generation remains relatively high and stable across all hours, with only a slight reduction during midday. This reflects its role as the baseload plant, operating essentially throughout the entire year, thereby providing continuous system stability. Naphtha generation too shows a similar behaviour, with higher output during night and early morning hours and reduced dispatch during midday and it is observed to operate for about 330 days in 2028, indicating its role as a mid merit resource that adjusts in response to solar generation. Furnace oil plants demonstrate an even stronger peaking characteristic, with minimal midday operation and increased generation during night peak hours. They are operated for about 280 days during off peak time and about 350 days during night peak hours, highlighting the function in meeting night peak demand. Diesel generation is used very sparingly, with near zero dispatch for most of the days and only small contributions during night peak hours, operating less than 150 days during 2028, which confirms its role as a high cost, peaking source.

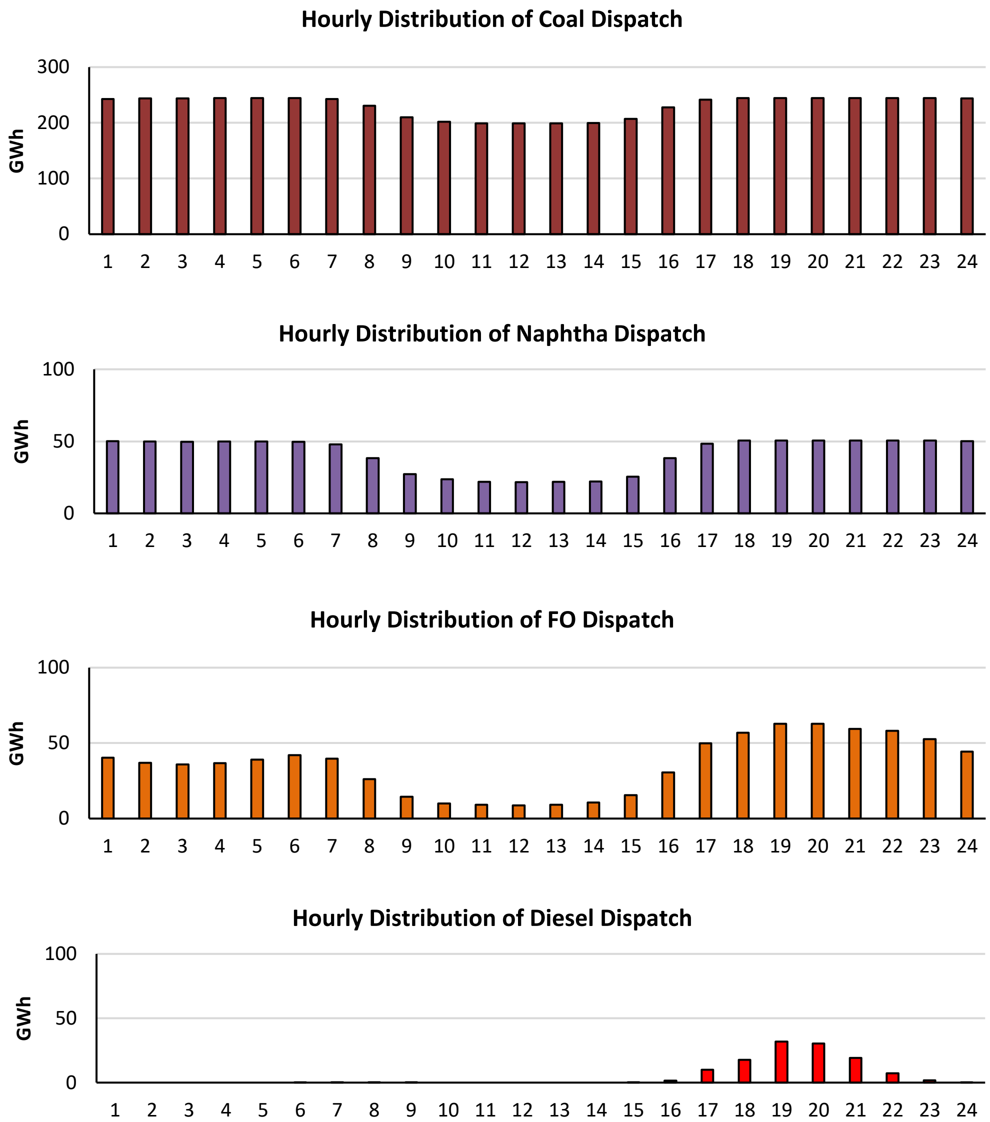


Figure 6: Thermal Power Plant Operation Pattern in 2028

No electricity generation is expected from diesel in majority days of the year due to rapid expansion of battery energy storage systems. Overall, the dispatch pattern clearly reflects the merit order structure in the system, where coal provides baseload, naphtha, furnace oil and diesel supply mid merit and peak demand requirements. During night peak, all flexible thermal resources ramp up, while midday reductions in thermal generation indicate displacement by solar PV generation. Similar operational behaviour is observed during 2027 and 2029 as well.

Annual fuel requirement and cost for fuel for the considered period is shown in Table 10.

Table 10: Annual Fuel Requirement and fuel cost for 2027-2029

		2027	2028	2029
Coal	Million metric ton	2.5	2.5	2.4
	Million USD	310	310	298
Naphtha	Million Liters	186	212	167
	Million USD	101	115	91
Furnace Oil	Million Liters	195	200	169
	Million USD	145	148	125
Diesel	Million Liters	64	35	56
	Million USD	49	27	42

The above oil requirement represents only a fraction of the refinery's total processing capacity and can therefore be met through local refinery production. Hence ensuring timely procurement of adequate amount of coal and crude oil is necessary.

4.5 Seasonal Variation in Dispatch

The generation mix is becoming increasingly dominated by renewable energy sources. As illustrated in figure 3, renewable energy availability is seasonal in nature, with noticeable variations across different periods of the year. The Dry Season (January to April), High Wind Season (May to September) and Wet Season (October to December) typically characterize the seasonal renewable energy availability and the corresponding system dispatch patterns throughout the year. Accordingly, the expected weekly system dispatch patterns for different seasons in the year 2028 are summarized in figure 7, figure 8 and figure 9 illustrating how thermal generation is adjusted to complement seasonal variations in renewable energy availability and how battery energy storage systems are utilized to maximize the absorption of excess renewable energy generation.

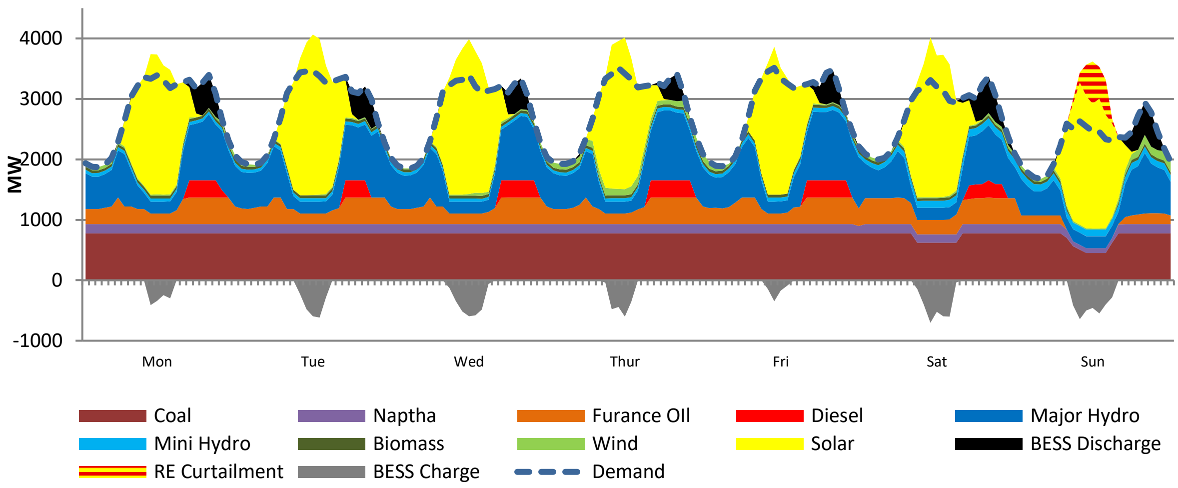


Figure 7: Sample Weekly Dispatch Pattern in 2028 Dry Season (January to April)

As shown in figure 7, during the dry season from January to April, solar energy production reaches its peak during daytime hours and excess generation is stored in battery energy storage systems for utilization during the night peak period. Wind energy generation during this season is generally low, while major hydro resources are strategically dispatched during night peak and off peak periods to maintain system balance. Renewable energy curtailments are primarily observed during daytime hours, particularly on Sundays and holidays when system demand is comparatively lower. During this period, all three coal power plant units are required to remain available, while other thermal power plants provide the necessary system balancing requirements.

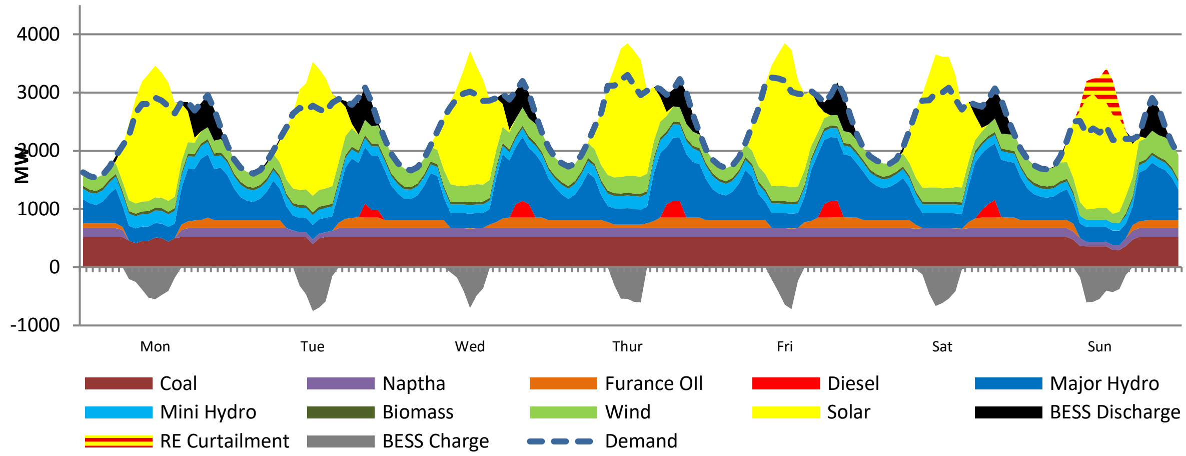


Figure 8: Sample Weekly Dispatch Pattern in 2028 High Wind Season (May to September)

As shown in figure 8, during the period from May to September, the southwest monsoon contributes to high wind energy generation. Together with significant hydro dispatch and average daytime solar generation, this results in a high share of renewable energy generation within the system. During this season, battery energy storage systems play a crucial role in energy shifting by storing energy during periods of excess supply and discharging it during periods of higher demand. However, as planned wind power capacity additions have not yet reached the required capacity levels, the full impact of overlapping generation from solar, wind and run of river hydro resources is not expected to materialize within the 2027–2029 planning horizon. Consequently, renewable energy curtailments are expected to remain largely confined to daytime periods on Sundays and other holidays.

As illustrated in figure 9, during the period from October to December, the inter monsoon and northeast monsoon seasons contribute to high inflows and increased generation from hydro resources. This enhanced water availability enables major hydro power plants to be effectively dispatched during night peak and off-peak periods. The storage capacity of major reservoirs is strategically managed to ensure adequate reservoir levels are maintained for utilization during the subsequent dry season. Solar energy production during the wet season can vary considerably, with certain days experiencing significantly reduced output due to weather conditions, while wind energy generation generally remains at average levels. Battery energy storage systems are utilized to shift excess solar energy generation by storing energy for later use. However, during certain periods of the season, storage systems may remain idle due to insufficient excess renewable energy available for charging. Renewable energy curtailments during the wet season are relatively low and only observed occasionally during daytime hours on Sundays and holidays.

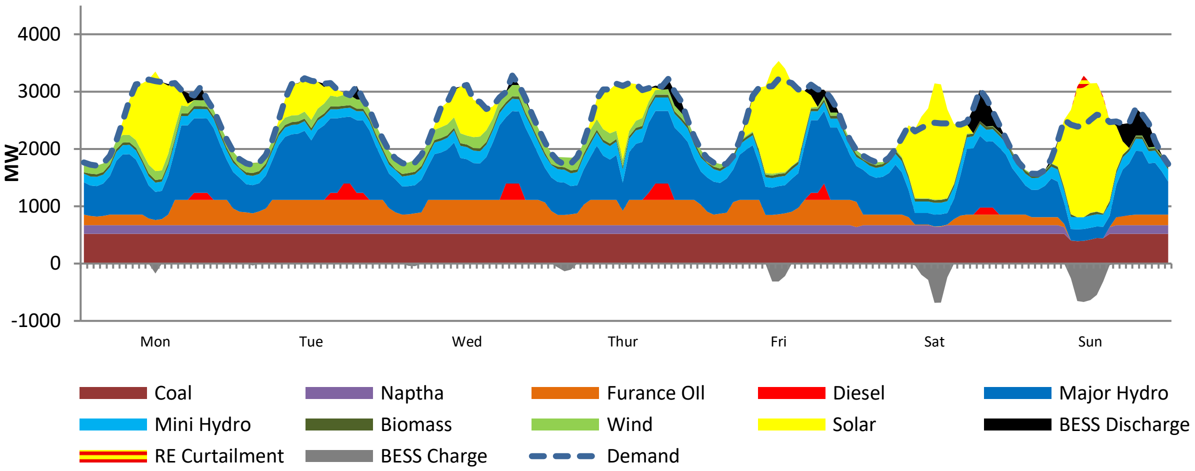


Figure 9: Sample Weekly Dispatch Pattern in 2028 Wet Season (October to December)

Sample weekly dispatch for the years 2027 and 2029 are shown in Annex 2. Monthly distribution of energy for the period 2027 to 2029 is given in Annex 3.

4.6 System Operational Assessment

The power system is expected to face increasingly challenging operational conditions during the period 2027–2029. The rapid growth of variable renewable energy generation shall significantly increase net load variability, reduce available synchronous inertia and increase system sensitivity to disturbances. The expected variations over main operational parameters for the three year period is summarized in table 11.

Table 11: Operational Parameters 2027-2029

Parameter	2027	2028	2029
Net Load Max Hourly Ramp up	951 MW	1,070 MW	1,145 MW
Net Load Max Hourly Ramp down	745 MW	816 MW	966 MW
Net Load Max 3 Hour Continuous Ramp up	1,927 MW	2,343 MW	2,465 MW
Net Load Max 3 Hour Continuous Ramp down	1,491 MW	1,620 MW	1,929 MW
Minimum System Synchronous Inertia H	1.1-1.5 s	0.8-1.3 s	0.7-1.2 s
Maximum ROCOF	1.9 Hz/s	2.4 Hz/s	2.5 Hz/s
Percentage of hours per year ROCOF can exceed 0.85 Hz/s	44%	56%	58%

Note: The above values are based only on generation side inertia capabilities, without the implementation of synchronous condensers and Grid forming BESS.

The projected net load ramping requirements indicate a substantial increase in system flexibility needs over the three year period. These conditions reflect the growing “duck curve” effect associated with high solar penetration, where rapid reductions in solar generation during evening hours must be compensated by dispatchable resources within short timeframes. Managing these ramping requirements will require significantly enhanced operational flexibility from the power system. Dispatchable Battery Energy Storage Systems, hydro power plants and the existing thermal generation fleet are expected to play a critical role in balancing these rapid variations in net demand.

In parallel with ramping challenges, the system is also expected to experience a significant deterioration in stability conditions due to declining synchronous inertia levels. Minimum system synchronous inertia is projected to reduce from approximately 1.1–1.5 seconds in 2027 to as low as 0.7–1.2 seconds by 2029. Lower inertia levels reduce the natural ability of the power system to resist frequency deviations following major disturbances, resulting in faster frequency dynamics and increased operational risk.

These trends highlight the emergence of critical system stability risks during the 2027–2029 period. In particular, the reduced availability of synchronous generation and increasing dominance of inverter based renewable resources will require urgent implementation of dedicated stability support solutions. Accelerated deployment of Synchronous Condensers will be essential to provide additional system strength, inertia support and voltage stability. In addition, Grid Forming (GFM) BESS technologies are expected to play a vital role in supporting frequency stability and system resilience under low inertia conditions.

However, successful integration of GFM BESS solutions will depend not only on deployment scale but also on the proper tuning and coordination of control parameters across multiple devices and system conditions. Poorly coordinated or improperly tuned GFM controls could lead to adverse control interactions, oscillatory behaviour and further system instability. Therefore, careful system wide coordination, dynamic studies and robust control parameter tuning will become critical operational requirements for maintaining secure and reliable grid operation during this transition period.

4.7 Investment Requirement

Technology wise upfront capital expenditure requirements for the period 2027–2029 are illustrated in figure 10. Timely investment in power generation, storage projects and transmission infrastructure is essential to ensure that plant commissioning schedules are achieved as planned. The capital investment requirements for power plant projects may be fulfilled through various financing mechanisms, including private sector investments, Public-Private Partnerships (PPP), concessional loan arrangements from funding agencies and other suitable financing models.

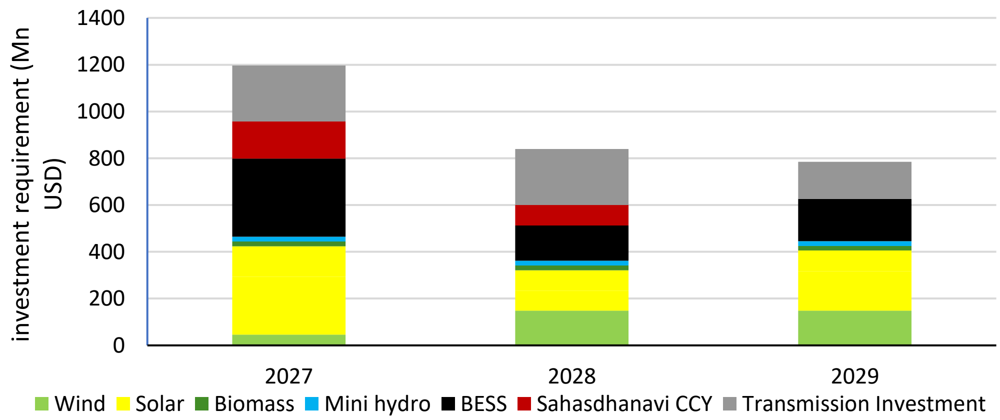


Figure 10: Investment Requirement for 2027-2029

4.8 Summary of Proposed Power Plant and Storage Additions

The proposed power plant additions during the period 2027-2029 are mainly focused on ensuring system adequacy, maintaining reserve margins, supporting increasing renewable energy integration and meeting growing electricity demand at lowest cost. The additions include renewable energy projects, energy storage systems, thermal generation required for system reliability, as well as transmission related stability support facilities.

The interim report on LTPSDP prioritizes renewable energy development, particularly solar PV and wind power, in line with national renewable energy targets. However, due to the variable nature of renewable generation, complementary Battery Energy Storage Systems are also proposed to ensure reliable system operation, frequency regulation and peak demand support. In addition, adequate thermal generation capacity is maintained to ensure system reliability and security of supply during periods of low renewable energy availability and peak demand conditions.

The proposed additions also consider the timely retirement of aging thermal power plants and the increasing operational challenges associated with high penetration of inverter based renewable energy resources. Therefore, implementation of synchronous condensers and grid strengthening projects are identified as important enabling measures to maintain adequate system strength and voltage stability. In this context, the planned retirement of aging thermal power plants may need to be reassessed, as some units could be retained in standby operation or converted to synchronous condensers to provide essential grid support services.

A summary of the proposed power plant additions for the period 2027-2029 is presented in table 12.

Table 12: Proposed Power Plant Additions 2027-2029

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2027					**100 MW Siyambalanduwa solar**							
2027	←					**342 MW Grid Connected Solar**						→
2027	←					200 MW Rooftop Solar						→
2027		**50 MW Nadukuda Wind**										
2027												**10 MW Biomass**
2027						**31 MW Moragolla Hydro**						**10 MW Mini Hydro**
2027			180 MW/720 MWh Expedited BESS									**50 MW/200 MWh BESS With Existing Solar 250 MW/1000 MWh Standalone BESS**
2028												**50 MW Sampur Solar** 100 MW Grid Connected Solar
2028	←					150 MW Rooftop Solar						→
2028		**100 MW Mullikulam Wind 60 MW Norochcholai Wind**										
2028												10 MW Biomass
2028												10 MW Mini Hydro
2028			**212 MW Sahasdhanavi Gas Turbine**									
2028			**100 MW/100 MWh Kolonnawa BESS 100 MW/400 MWh Southern BESS**									100 MW/400 MWh Utility Scale BESS
2029												300 MW Grid Connected Solar
2029	←					150 MW Rooftop Solar						→
2029		60 MW Mannar Wind			100 MW Kondachchi Wind							
2029												10 MW Biomass
2029												10 MW Mini Hydro
2029			**100 MW Sahasdhanavi Steam Turbine**									
2029												300 MW/1200 MWh Utility Scale BESS

Note: Committed power projects are shown in bold text

4.9 Summary of Proposed Transmission Infrastructure Development

Achieving a least cost and sustainable power system in the long term will require significantly higher integration of renewable energy resources into the national electricity grid. While solar generation and energy storage technologies are expected to continue playing an important role in the future energy mix, a well connected and reliable electricity transmission network is essential to ensure energy security, system reliability and cost effective electricity generation and transmission.

Sri Lanka possesses substantial wind energy potential, particularly in the Northern and North Western regions. However, the large scale development of these renewable energy resources is currently constrained by inadequate transmission infrastructure and limited network capacity in high resource zones. Existing transmission networks are insufficient to accommodate the anticipated growth in renewable energy generation, resulting in bottlenecks that restrict the evacuation and integration of new renewable energy projects into the national grid.

To unlock the full potential of renewable energy development and facilitate the timely achievement of national energy transition objectives, the implementation of strategic transmission infrastructure projects must be accelerated. Expedited execution of these projects will enhance grid connectivity to renewable energy resource regions, strengthen system resilience, improve operational flexibility and enable the efficient transfer of renewable power to major demand centres across the country.

It should be noted that the proposed transmission developments are based on the Long Term Transmission Development Plan (LTTDP) 2025–2034. Detailed power system stability studies for the network developments proposed for the period 2027–2029, as presented in the Interim Report are currently in progress and may lead to further refinements of these proposals.

4.9.1 Transmission Capacity Enhancement Projects

Following planned transmission development projects shall be accorded with high priority and fast tracked through the provision of necessary government approvals, land acquisition and clearance processes, environmental permits, financing arrangements and institutional support mechanisms as these are essential to fully utilize the already installed generation and to absorb any renewables to the system if available. The planned completion years are based on the latest long term transmission development plan and may be subject to revision during project implementation, depending on project progress and any implementation related constraints.

1. Re-Construction of Samanalawewa-Embilipitiya 132kV Transmission Line with Zebra (Planned Completion Year -2028)
2. Re-Construction of Pannipitiya-Panadura – Matugama 132kV Transmission Line with 2xZebra (Planned Completion Year -2028)
3. Re-Construction of Laxapana - Wimalasurendra 132kV Transmission Line with Zebra (Planned Completion Year -2028)
4. Re-Construction of New Laxapana - Balangoda 132kV Transmission Line with Zebra (Planned Completion Year -2028)
5. Capacity enhancement of 132kV Lynx transmission lines to Zebra - Laxapana Complex (Planned Completion Year -2028)
6. Re-Construction of Badulla - Laxapana 132kV Transmission Line with Zebra (Planned Completion Year -2030)

4.9.2 Proposed Transmission Development Projects

The following planned transmission development projects shall be accorded high priority and fast tracked through the timely provision of necessary government approvals, land acquisition and clearance processes, environmental permits, financing arrangements and institutional support mechanisms. They are essential for facilitating renewable energy integration, strengthening network reliability and ensuring the efficient operation of the national power system. The planned completion years are based on the latest long term transmission development plan and may be subject to revision during project implementation, depending on project progress and any implementation related constraints.

1. Vavuniya 220 kV Transmission Development (Planned Completion Year -2028)

   Strengthening transmission capacity in the Northern Province to facilitate the integration of planned renewable energy projects and improve regional network reliability.

2. Capacity enhancement through Augmentation of Kurunegala (31.5 MVA) & Mannar (2 x 45 MVA) Grid Substations (Planned Completion Year -2028/2029)

   Enhancing grid capacity is essential to accommodate increasing demand and generation requirements while maintaining the reliability, stability and resilience of the power system.

3. Development of the Northern 400 kV Transmission Network (Planned Completion Year -2030)

   Establishing a high capacity transmission backbone to support large scale renewable energy generation, particularly wind power developments in the Northern region and to enhance long distance power transfer capability.

4. Norochcholai – Wariyapola 220 kV Transmission Development (Planned Completion Year -2030)

   Improving network strength and transmission capacity to accommodate increased renewable energy flows and optimize power system operations.

5. Monaragala – Hambantota 220 kV Transmission Development (Planned Completion Year -2031)

   Facilitating the evacuation of renewable energy from the South Eastern region and supporting future renewable energy expansion in the area.

6. New Habarana – Kirindiwela 400 kV Transmission Development (Planned Completion Year -2032)

   Establishing a critical high capacity transmission backbone is essential to strengthen the national grid and improve the transfer of renewable energy from generation rich regions in Northern Eastern and North Western to major load centres.

7. Development of Colombo City Transmission Network (Planned Completion Year -2030)

   Construction of Colombo G, Colombo K, Sub P, Sub Q grid substations and associated Underground cable network to improve network reliability and meet increasing consumer demand.

8. Development of 132/33 kV Grid Substations (Planned Completion Years -2028-2031)

   Construction of Chemmani, Keeriyankalliya, Ekala, Kalmunai, Wariyapola and Tissamaharama grid substations to improve system reliability and operational flexibility, facilitate the evacuation of renewable energy and meet increasing consumer demand.

The timely completion of these transmission projects is critical for removing network constraints, enabling large scale renewable energy deployment, minimizing renewable energy curtailment and achieving the country's long term least cost objectives.

4.10 Deviations from Previous Plan

Input data considered in the process of preparation of LTPSDP 2027-2046 reflect the latest available information on electricity demand growth, fuel price projections, technology costs and system requirements. The resulting changes have influenced the generation and storage additions and investment priorities recommended in the current plan to deviate from the LTGEP 2025-2044. Comparison of demand forecast with LTGEP 2025-2044 is shown in table 2 in section 2.1.

The comparison of cumulative generation and storage capacity is given in table 13.

Table 13: Comparison of Cumulative Generation and Storage Capacity

	Wind		**Solar**		**BESS**	
	LTGEP 2025-2044	LTPSDP-Interim	LTGEP 2025-2044	LTPSDP-Interim	LTGEP 2025-2044	LTPSDP-Interim
2027	627 MW	354 MW	2,082 MW	3,804 MW	105 MW/110 MWh	645 MW/ 2,570 MWh
2028	827 MW	514 MW	2,532 MW	4,104 MW	205 MW/510 MWh	945 MW/ 3,470 MWh
2029	977 MW	674 MW	2,982 MW	4,554 MW	305 MW/910 MWh	1,245 MW/ 4,670 MWh

4.11 Contingency Scenario Analysis

It is important to assess the impact of both controllable and uncontrollable risk events, which could lead to inadequacy of supply to meet the capacity and energy demand in the immediate future years. The Contingency Analysis focuses on identifying impacts and solutions for dry hydro conditions, outage of major power plant and further increase in electricity demand.

4.11.1 Risk Events

1. Variation in Hydrology

Hydrology is a critical factor affecting the adequacy and reliability of the Sri Lankan power system. Historically, periods of below-average rainfall and reduced reservoir inflows have posed a significant risk to electricity supply. The likelihood of dry hydro conditions is considered high due to forecasts indicating the possible development of El Niño conditions during the early years of the planning period. Under such conditions, the annual energy generation from hydroelectric resources can decrease by approximately 500–1,000 GWh from average hydro conditions, depending on the severity.

2. Variation in Demand

Variation in electricity demand from the base demand projection is considered a key source of uncertainty in power system planning. Although the base demand forecast reasonably reflects the latest trends in economic growth, electrification, and electricity consumption patterns, more rapid than anticipated changes in these factors could have a significant impact on system adequacy and reliability. While the likelihood of electricity demand exceeding the base demand projection is considered low, the level of uncertainty associated with future demand growth remains high due to evolving consumption patterns and accelerated electrification. The projected demand variance of high demand scenarios is tabulated in table 14.

Table 14: Variation of Demand in High Demand Scenario

Year	Generation (GWh)			Day Peak (MW)			Night Peak (MW)		
	Base	High	Difference	Base	High	Difference	Base	High	Difference
2027	20,549	20,743	**194**	3,342	3,463	**121**	3,327	3,448	**121**
2028	21,587	21,845	**258**	3,514	3,651	**137**	3,482	3,617	**135**
2029	22,616	22,944	**328**	3,686	3,838	**152**	3,634	3,784	**150**

3. Long Period Outage of a Major Power Plant

A prolonged outage of a major generating unit during the dry season represents a significant risk to system adequacy. The increasing requirement for cyclic operation of coal fired generating units, can accelerate equipment wear and increase the probability of forced outages. The likelihood of a prolonged outage of a major power plant is considered medium.

Accordingly, the forced outage of one unit of the Lakvijaya Coal Power Plant for a duration of 3 months during the dry season was considered as a risk event in the analysis. It is to be noted that any planned maintenance activities scheduled during the end of the year would be rescheduled to coincide with the forced outage, thereby minimizing the additional impact on generation availability.

4.11.2 Evaluation of Contingencies

Capacity deficit risk is the inability of firm capacity to meet the peak demand in the critical period with minimum reliability requirement. The Energy Deficit risk is the possibility that the available plants will not be able to provide the total energy requirement within the reliability criteria.

Contingency events are analysed to identify the severity of simultaneous occurrence of the risk events identified in 4.11.1 for period from 2027 to 2029 and mitigation measures required where necessary. Under the current planning timeframe and prevailing economic conditions, procuring short term supplementary generation capacity solely to address temporary capacity deficits is not considered a cost effective option. On the other hand, battery energy storage systems introduced to manage such contingencies should be regarded as long term system assets rather than temporary measures, as they are expected to remain in operation well beyond the contingency period.

a) Contingency Event 1 - Dry Hydro Condition and Long Period Outage of Major power plant

Sri Lankas energy mix has evolved rapidly within the last three years with rapid expansion of renewable energy and planned addition of storage solutions. Hence the grid has become more resilient to dry hydro conditions than in the past. The energy requirement under dry hydro conditions can be adequately met with the planned generation capacities.

However, the loss of a 270 MW generating unit significantly reduces the planning reserve margin particularly during critical period of the night peak demand in the dry season. An additional firm capacity of approximately 100 MW/400 MWh dispatchable BESS is required to maintain minimum system reliability levels for the night peak operation in year 2027. No further capacity additions are required for 2028–2029.

Although the reduction in reserve margin increases the risk to system adequacy, the energy deficit risk is managed, as the remaining generating fleet is capable of meeting the annual energy requirement within the reliability criteria. Nevertheless, the system operates with reduced operational flexibility and resilience during these periods.

b) Contingency Event 2 - Dry Hydro Condition and High demand scenario

The most cost effective method of managing impacts of high demand scenarios is by implementing cost reflective time of use tariff mechanisms.

Even in the expected high demand scenario, energy deficit risk is not expected in all three years as the minimum reliability requirement can be achieved with the availability of other power plants. However, under the optimization requirements an additional 170 MW/680 MWh dispatchable BESS and 100 MW solar addition is required for year 2027 to meet the increase in demand. No further capacity additions are required for 2028–2029.

c) Contingency Event 3-Dry Hydro Condition and Long Period Outage of Major power plant in High demand scenario

This is considered as one of the most severe risks that can affect the operation of the power system. There can be energy deficit risks during critical periods without additional support measures in the event of occurrence of combined risk events of largest unit outage and high demand scenario under dry hydro conditions.

In order to mitigate such risk event, an additional 270 MW/1080 MWh dispatchable BESS and 100 MW solar addition is required for year 2027. No further capacity additions are required for 2028–2029.

Accordingly, the contingency capacities identified under a), b) and c) could be considered if the associated risk events mentioned in 4.11.1 are expected to materialize. In such event, procurement can be done by advancing the capacities identified in the Interim Report for the 2028–2029 period.

5. Recommendation

5.1 Timely Completion of Ongoing Generation, Storage and Transmission Projects

Timely commissioning of committed generation and energy storage projects as listed in section 2.2 and 2.3 is essential to ensure system reliability and avoid potential power supply shortages. Integration of low cost renewable energy projects is important to reduce generation costs, while thermal capacity is required to support system security during peak demand periods and contingencies.

i. Battery Energy Storage – 500 MW / 1700 MWh (4 Tender projects)
   a) 50 MW/ 200 MWh Tender with existing solar
   b) 250 MW/ 1000 MWh Tender
   c) 100 MW / 100 MWh Kolonnawa BESS
   d) 100 MW/ 400 MWh Southern BESS

ii. Wind Energy Projects – 210 MW (Multiple projects)

iii. Solar Energy Projects – 492 MW (Multiple SPPA/PPA projects)

iv. Hydro Energy Projects – 41 MW (1 Major Hydro, multiple SPPA projects)

v. Thermal Energy Projects – 312 MW (1 project)

The ongoing and committed transmission development projects listed in section 2.4 are currently at various stages of development. Their timely implementation and commissioning require accelerated progress through coordinated action among relevant institutions. It is also necessary to address implementation bottlenecks and facilitate the expeditious completion of these projects. The transmission development projects are as follows,

i. Habarana – Veyangoda 220 kV Transmission Project

ii. Padukka – Horana 132 kV Transmission Line

iii. Construction of the Hambantota – Matara 132 kV Double-Circuit Transmission Line

iv. Construction of the New Habarana – Kappalthurei 220 kV Transmission Line

v. Construction of the Kerawalapitiya Second Cable

vi. Construction of the Sampur – Kappalthurei 220 kV Transmission Line

vii. Construction of Victoria-Rantambe 220kV Transmission Line

viii. All the ongoing projects under PSRSIEP and NTDND&EIP-I

5.2 Initiate Procurement of New Renewable Energy and Storage Projects

i. A **cumulative 180 MW/720 MWh BESS** is expected to be integrated into the system expeditiously by **March 2027**. Accordingly, a suitable procurement approach should be identified without delay to ensure timely deployment. Utility scale BESS are preferred for this requirement due to their lower cost and higher controllability. However, small scale BESS installations through prosumers may also be considered, given their relatively shorter implementation timelines. In the absence of adequate controllability, such installations shall operate with dedicated predefined discharge time slots or operate in mechanisms similar to a Virtual Power Plant aggregator scheme.

The allocation for the prosumer based BESS installation shall be limited to the first year unless procurement costs become comparable to utility scale BESS installations. However, in the event that demand growth exceeds the planned levels, the deployment of additional prosumer based BESS installations may be considered at the time such requirements are identified.

ii. A new capacity requirement of **100 MW/400MWh BESS** may be procured with solar or standalone BESS projects to be commissioned by **December 2028**. In the event projects are procured as standalone BESS projects, 100 MW of solar capacity may be procured as grid scale projects.

iii. A new capacity requirement of **300 MW/1200MWh BESS** may be procured with solar or standalone BESS projects to be commissioned by **December 2029**. In the event projects are procured as standalone BESS projects, 300 MW of solar capacity may be procured as grid scale projects.

iv. Two projects of **60 MW wind in Mannar and 100 MW wind in Kondachchi** are to be initiated with the expected development in year **2029**. Additional wind capacity may be considered during 2029, subject to the identification of feasible wind power projects that can be implemented within that time.

v. **Rooftop solar** capacity additions for the **three year period shall be 500 MW**, in which part may be procured with BESS installations as outlined in item (i) of 5.2. Distribution licensees shall procure rooftop solar capacity only within these specified limits, taking into consideration the capabilities and constraints of the LV/MV distribution network.

All future wind and grid connected solar projects shall be procured with the necessary grid support capabilities. They shall also possess the capability to operate in accordance with dispatch instructions issued by the National System Control Centre.

Annual additions from mini hydro and biomass projects are not strictly limited to the planned capacities and higher capacity additions may be considered and evaluated on a case by case basis.

Further, the development of pumped storage hydropower project, which are expected to play a critical role as energy storage option in the long term, requires considerable lead time for project preparation, environmental clearances, land acquisition and financing arrangements. Therefore, early action is necessary to undertake these preliminary activities to ensure timely implementation.

5.3 Timely Integration of the Renewable Energy Management System and Smart Metering Systems

The integration of the **Renewable Energy Management System (REMS) to the National System Control Centre together with modernization of the existing SCADA/Energy Management System** is critical to manage the high portion of renewable energy that is been connected to the grid. This shall improve real time monitoring, enhance grid visibility and enable more efficient dispatch and control of variable renewable energy resources. Accordingly, the project shall be expedited for completion by **2028**.

In addition, the deployment of smart meters for rooftop solar PV installations and the establishment of communication systems to provide visibility at Distribution Control Centres, together with aggregated visibility at the National System Control Centre, are also necessary.

5.4 Implementation of Demand Management Measures to Reduce Curtailment

As renewable energy curtailments are predominantly observed during Sundays, it is necessary to introduce mechanisms to **shift a portion of weekday electricity demand to Sundays**. This may be achieved through appropriate tariff structures that encourage industries and commercial establishments to operate on Sundays while reducing demand during weekdays. A rotational mechanism may also be introduced for consumers to select designated weekdays for demand shifting, thereby ensuring balanced demand reduction across the week. In addition, electric vehicle charging may be encouraged through special Sunday tariff schemes.

Further, the introduction of **cost reflective Time of Use tariffs** would encourage consumers to shift a portion of their night time electricity consumption to daytime periods, thereby reducing renewable energy curtailments during daytime hours and minimizing the requirement for high cost generation during the night peak period.

5.5 Implementation of Transmission Line Projects for Renewable Energy Evacuation

Accelerate the implementation of strategic transmission network strengthening projects to facilitate large scale renewable energy integration, particularly from high potential wind and solar resource regions. Timely expansion of the transmission system is essential to eliminate network constraints, improve grid reliability and operational flexibility, enhance energy security and enable the least-cost transition towards a sustainable and low carbon power sector.

Accordingly, following transmission capacity enhancement projects need to be prioritized.

i. Re-Construction of Samanalawewa-Embilipitiya 132kV Transmission Line with Zebra
ii. Re-Construction of Pannipitiya-Panadura – Matugama 132kV Transmission Line with 2xZebra
iii. Re-Construction of Laxapana - Wimalasurendra 132kV Transmission Line with Zebra
iv. Re-Construction of New Laxapana - Balangoda 132kV Transmission Line with Zebra
v. Capacity enhancement of 132kV Lynx transmission lines to Zebra - Laxapana Complex
vi. Reconstruction of Badulla - Laxapana 132kV Transmission Line with Zebra

The following transmission infrastructure projects are considered critical for facilitating future renewable energy integration. Priority will be given to accelerating transmission development to renewable energy zones that has wind resource potential.

i. Vavuniya 220 kV Transmission Development
ii. Capacity enhancement through Augmentation of Kurunegala (31.5 MVA) & Mannar (2 x 45 MVA) Grid Substations
iii. Development of the Northern 400 kV Transmission Network

iv. Norochcholai – Wariyapola 220 kV Transmission Development

v. Monaragala – Hambantota 220 kV Transmission Development

vi. New Habarana – Kirindiwela 400 kV Transmission Development

vii. Development of Colombo City Transmission Network (Construction of Colombo G, Colombo K, Sub P, Sub Q grid substations and associated UG cable network)

viii. Development of 132/33 kV Grid Substations (Construction of Chemmani, Keeriyankalliya, Ekala, Kalmunai, Wariyapola and Tissamaharama grid substations)

5.6 Implementation of System Strength and Stability Support Measures

The increasing penetration of inverter based renewable energy resources, is fundamentally changing the operational characteristics of the power system. While these technologies contribute significantly to the decarbonization of the electricity sector, their large scale integration results in a reduction of system inertia, short-circuit strength and natural frequency response traditionally provided by synchronous generators. Consequently, the power system becomes more susceptible to voltage instability, frequency excursions, oscillatory behavior and other dynamic security challenges, particularly during major disturbances and contingency events.

As the share of inverter based generation continues to increase, it is essential to implement appropriate system strength and stability enhancement measures to maintain secure and reliable grid operation. Timely investment in stability support infrastructure and advanced control capabilities will be critical to mitigating the risk of widespread system disturbances, cascading failures and island-wide blackouts while enabling higher levels of renewable energy integration.

Accordingly, the following actions are recommended:

i. Accelerate the procurement, financing arrangements, regulatory approvals and implementation activities required for the installation of **two 75 MVA synchronous condenser units each at New Habarana and Mannar and the 300 MVAr STATCOM facility at the Padukka 220 kV Grid Substation (100 MVAr at stage 1),** with the objective of achieving commissioning by 2029. These facilities will enhance system strength, improve voltage regulation, increase fault current contribution and provide dynamic reactive power support to maintain secure network operation under high renewable energy penetration scenarios.

ii. Assess and incorporate **synchronous condenser mode operation capabilities at existing and retired major thermal and hydropower generating stations,** together with appropriate governor tuning and control system enhancements, to improve frequency response, inertia support, voltage control and overall power system stability. Existing generating assets should be leveraged to provide essential system services during periods of high renewable energy output and reduced synchronous generation dispatch.

iii. Ensure that a significant proportion of Battery Energy Storage Systems (BESS) deployed within the power system are equipped with **grid forming inverter capabilities**. Appropriate technical standards, performance requirements and coordinated tuning of control parameters should be established to enable these facilities to provide synthetic inertia, voltage support, frequency regulation, black-start capability and other essential grid support services necessary for maintaining system stability in a low inertia power system.

iv. Develop and implement a **comprehensive system strength framework and ancillary services strategy** to identify future stability requirements, establish technical performance standards for inverter based resources and ensure the adequate provision of frequency control, voltage support, inertia and fault level contributions as renewable energy penetration increases. It is important to establish a technical review of the current UFLS scheme parameters relative to system ROCOF dynamics. The operational ROCOF withstand and frequency response capabilities of all major conventional generating units and distributed energy resources have to be adjusted considering their capabilities.

v. Develop and implement a **Wide Area Monitoring System (WAMS)** to enhance real time grid visibility, situational awareness and dynamic system security. This shall include the installation of **Phasor Measurement Units (PMUs)** at strategically selected transmission substations and critical network nodes for high resolution synchronized data acquisition. The centralized WAMS control center requires to be established for real time monitoring, analytics, visualization and disturbance detection which shall be integrated with upgraded SCADA/EMS platforms. The system should support advanced applications such as oscillation monitoring, voltage stability assessment, event analysis and early warning systems, thereby improving grid observability, operational decision making and response capabilities under increasingly complex operating conditions associated with high renewable energy penetration.

The timely implementation of these measures will be critical to maintaining power system security, reliability and resilience while supporting the transition towards a high renewable, low carbon electricity sector.

Implementation timelines of the above recommendations are given in Annex 4.

Candidate Thermal and Renewable Plant Details

Table A1.1: Details of candidate ORE technologies

ORE Technology	Pure Capital Cost (USD/kW)	Fixed O&M Cost (% of the capital cost)	Construction years
Solar (Large Scale)	525	1.5 %	1
Solar (Distributed)	567	0.9 %	1
Floating solar	683	1.5 %	1.5
Onshore Wind	856	2.5 %	2
Biomass	1,871	4.0 %	1.5
Mini hydro	1,932	2.5 %	1.5

Table A1.2: Details of candidate Storage technologies

Technology	Pure Capital Cost (USD/kW)	Fixed O&M Cost (USD/kW year)	Construction years
Utility Scale BESS (2 hour)	297	5.1	1.5
Utility Scale BESS (4 hour)	565	8.1	1.5
Distributed Scale BESS (2 hour)	628	8	1
Distributed Scale BESS (4 hour)	820	10	1

Table A1.3: Cost details of candidate thermal technologies

Plant	Pure Unit Cost (USD/kW)	Construct. Period (Years)	Fixed O&M cost (USD/kW year)	Variable O&M cost (USD/ MWh)
50 MW IC Engine	1,039	2	15.6	6.57
100 MW IC Engine	972	2	15.6	6.57
200 MW IC Engine	938	2	15.6	6.57
50 MW Gas Turbine (Aero)	1,078	2	18.7	5.50
100 MW Gas Turbine (Aero)	785	2	18.7	5.50
50 MW Gas Turbine	907	2	8.1	5.26
100 MW Gas Turbine	695	2	8.1	5.26
200 MW Gas Turbine	567	2	8.1	5.26
300 MW Gas Turbine	495	2	8.1	5.26

Sources: (Gas Turbine World Handbook 2025, OEM data, Feasibility Studies)
Note: All IC Engine and Gas Turbine power plants are designed to operate on dual fuel capability.

Table A1.4: Characteristics of candidate thermal technologies

Plant	Max Load (MW)	Min Load (MW)	Heat Rate (kcal/kWh)		Full Load Efficiency (Net, HHV) %	FOR %
			Full	min		
50 MW IC Engine	47.1	2.12	2,098	3,063	41.1	2.5
100 MW IC Engine	101.9	3.71	2,100	3,174	41.0	2.5
200 MW IC Engine	203.8	3.59	2,099	3,275	41.0	2.5
50 MW Gas Turbine (Aero)	49.5	24.8	2,349	3,053	36.7	8
100 MW Gas Turbine (Aero)	128.4	64.2	2,411	3,134	35.7	8
50 MW Gas Turbine	41.1	16.4	2,921	3,798	29.5	8
100 MW Gas Turbine	106.4	53.2	2,548	3,312	33.8	8
200 MW Gas Turbine	191.9	76.7	2,568	3,338	33.5	8
300 MW Gas Turbine	268.6	61.8	2,519	3,275	34.2	8

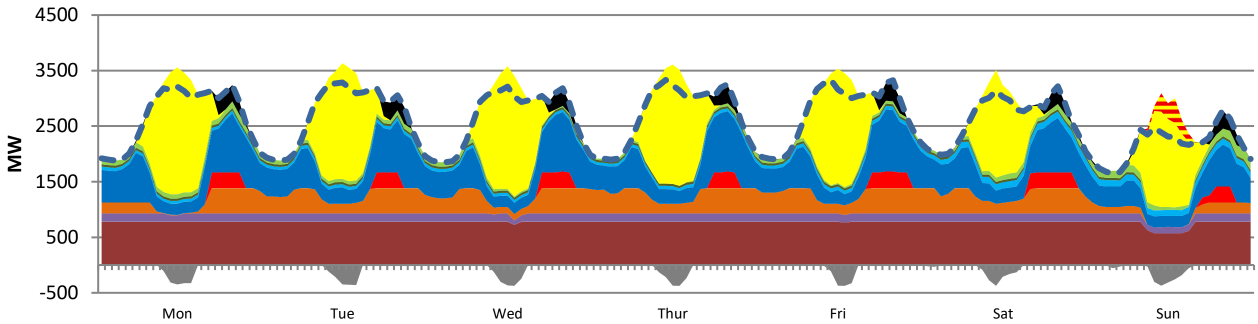
Power Plant Capacities are based on Net Capacity and Heat rates are based on HHV
Sources: (Gas Turbine World Handbook 2025, OEM data, Feasibility Studies)

Annex 2

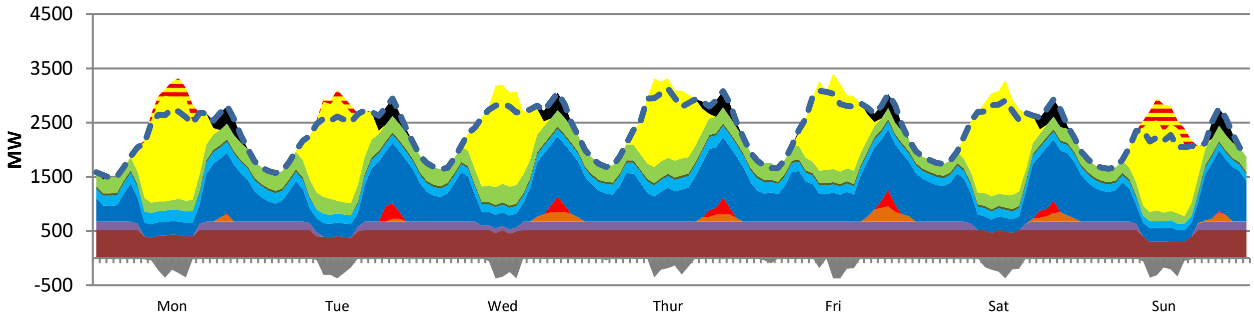
Seasonal Variation in Dispatch

Year 2027

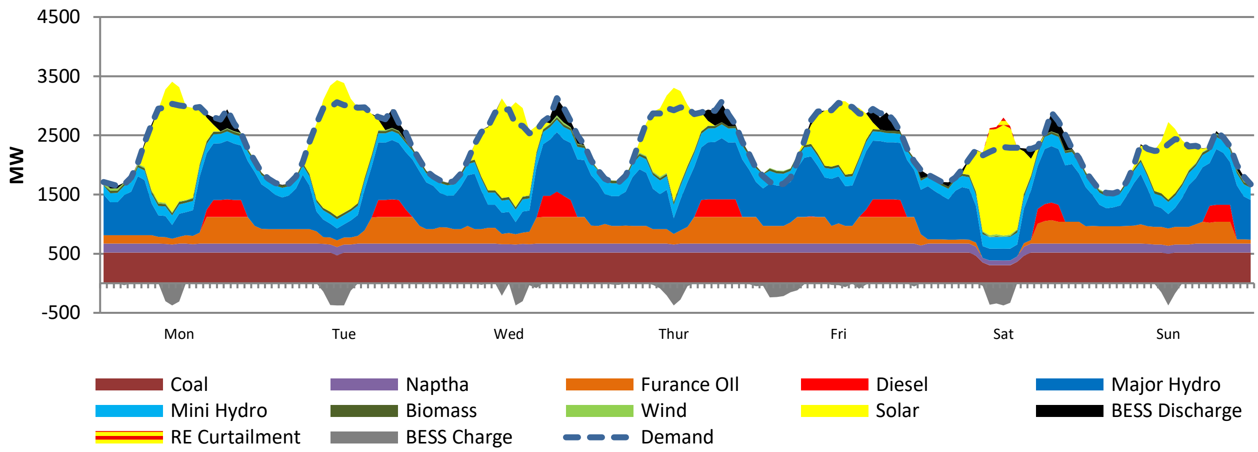
Dry Season (January to April)



High Wind Season (May to September)

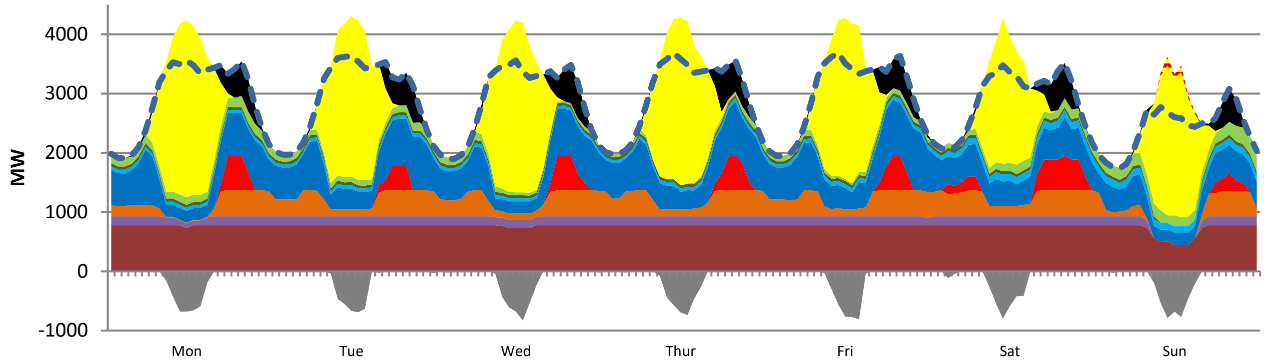


Wet Season (October to December)

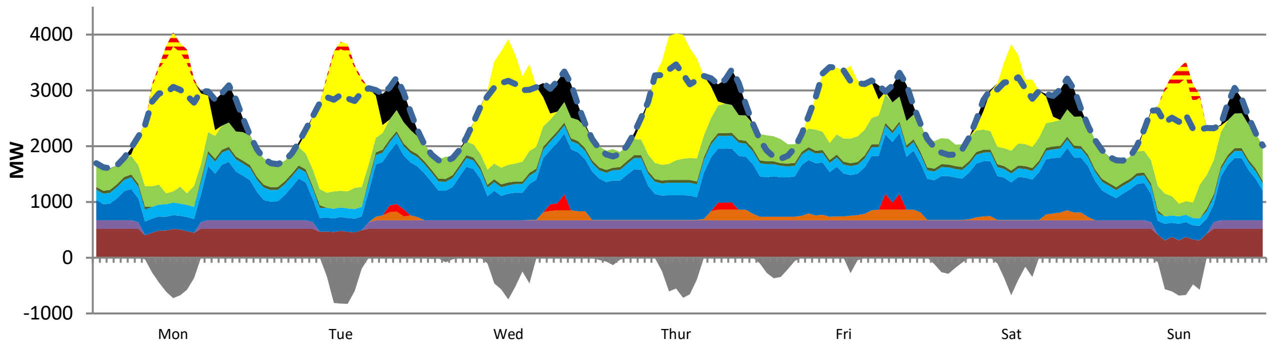


Year 2029

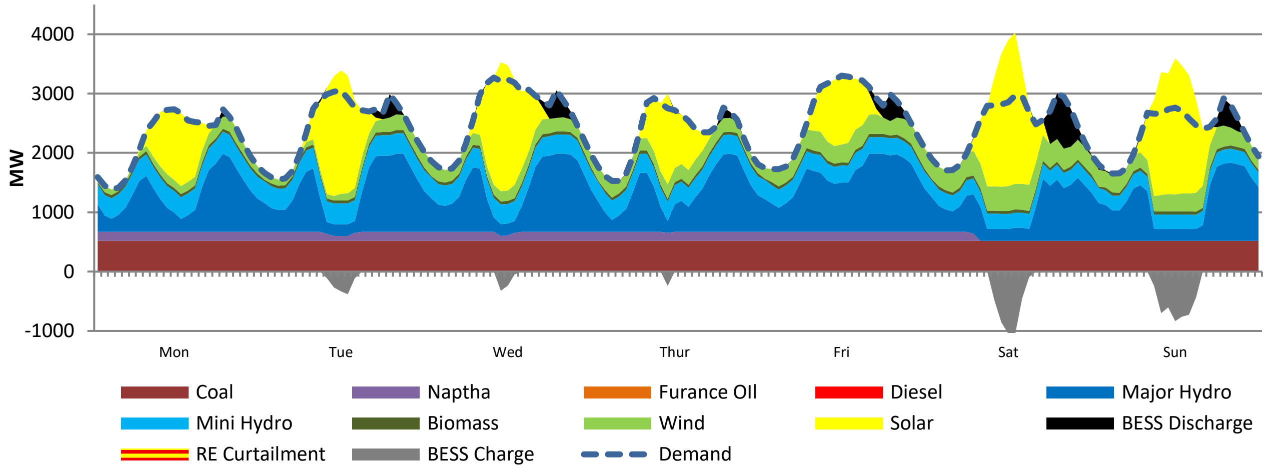
Dry Season (January to April)



High Wind Season (May to September)

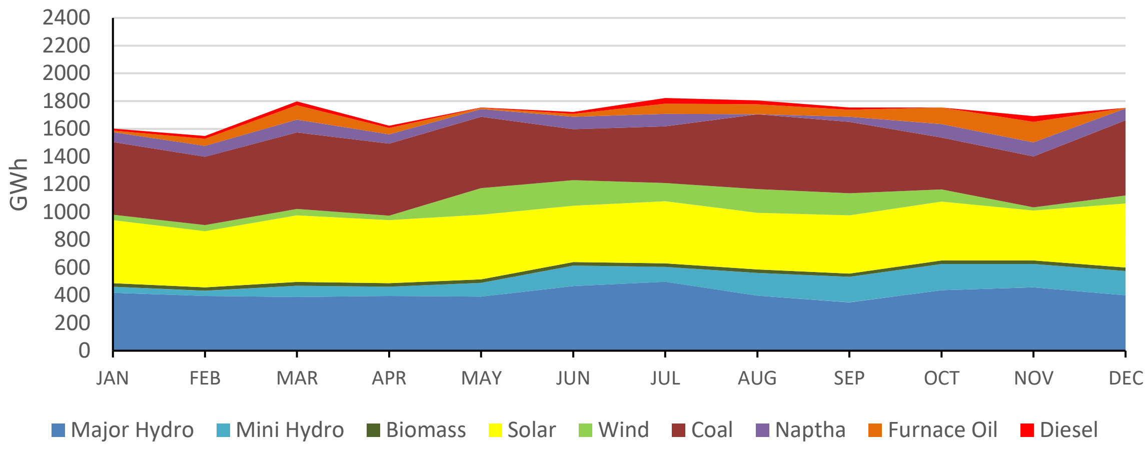


Wet Season (October to December)

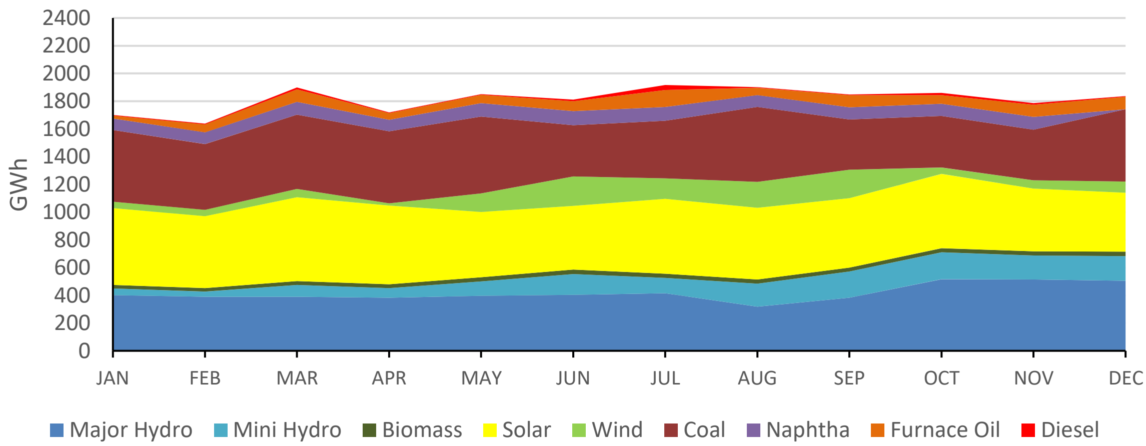


Monthly Distribution of Energy

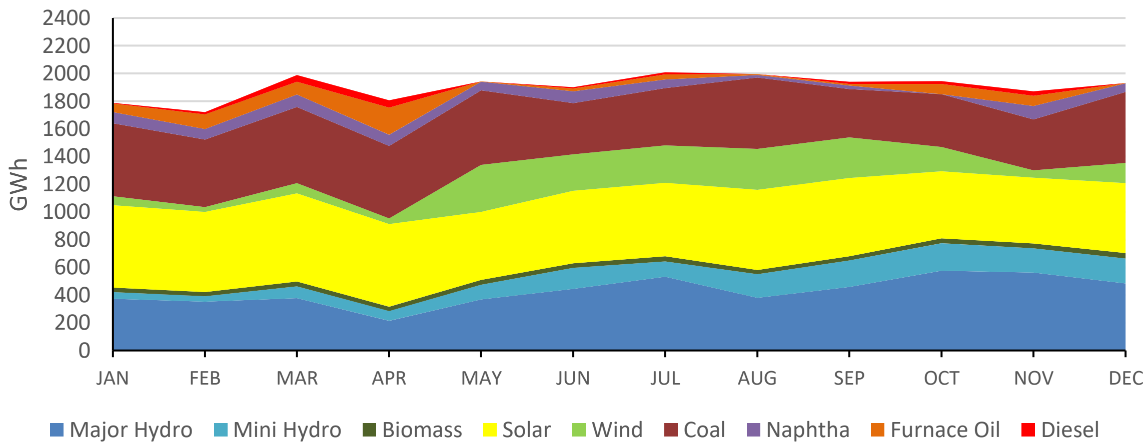
Year 2027



Year 2028



Year 2029



Note : Under stochastic renewable energy generation and varying weather conditions the actual energy distribution among sources may differ from the values presented.

Annex 4

Implementation Plans for Recommendations

5.1. Ongoing Generation, Storage and Transmission Projects

Generation and Storage Projects

Project	Completed By	Remarks	Responsibility
31 MW Moragolla hydro power project	2027	Construction is in its final stage	NTNSP – Project Execution
100 MW Siyambalanduwa solar power project	2027	Construction in progress	Developer – Project Execution
342 MW Ground mounted solar projects under FiT & Tender	2027	SPPA & PPA Signed/ Pending	Developer – Project Execution
50 MW Mannar wind project	2027	Construction in progress	Developer – Project Execution
10 MW Biomass	2027	SPPA Signed	Developer – Project Execution
10 MW Minihydro	2027	SPPA Signed	Developer – Project Execution
25 x 10 MW/ 40 MWh BESS Tender	2027	Tender floated	NSO – Project Initiation Developer – Project Execution
50 MW / 200 MWh BESS from existing ground mounted solar tender	2027	Tender to be floated	NSO – Project Initiation Developer – Project Execution
50 MW Sampur Solar power project	2028	EPC tender technical evaluation in progress	NSO – Project Initiation EGL NTPC Joint Venture – Project Execution
100 MW Mullikulam Wind power project	2028	PPA to be signed	NSO – Project Initiation Developer – Project Execution
60 MW Wind power projects under FiT	2028	SPPA Signed	Developer – Project Execution
100 MW / 100 MWh Kolonnawa BESS	2028	Tender evaluation in progress	NSO – Project Initiation NTNSP – Project Execution
100 MW / 400 MWh Siyambaladuwa BESS	2028	RFP preparation in progress with ADB	NSO – Project Initiation Developer – Project Execution
212 MW Gas Turbine of Sahasdhanavi Combined Cycle Plant (Kerawalapitiya)	2028	Construction in progress	Developer – Project Execution
100 MW Steam Turbine of Sahasdhanavi Combined Cycle Plant (Kerawalapitiya)	2029	Construction in progress	Developer – Project Execution

Ministry of Energy is expected to take timely action to obtain necessary cabinet approvals for the decisions on financing options and decisions on subsequent procurement of all the relevant projects.

Transmission Projects

Project	Completed By	Remarks	Responsibility
Habarana – Veyangoda 220 kV Transmission Project	2027	Preconstruction / Construction in progress	NTNSP
Padukka – Horana 132 kV Transmission Line	2027		
Construction of the Kerawalapitiya Second Cable	2027		
Construction of Victoria-Rantambe 220kV Transmission Line	2027		
Construction of the Hambantota – Matara 132 kV Double-Circuit Transmission Line	2028		
Construction of the Sampur – Kappalthurei 220 kV Transmission Line	2028		
All the ongoing projects under PSRSIEP and NTDND&EIP-I	2028/2029		
Construction of the New Habarana – Kappalthurei 220 kV Transmission Line	2029		

Ministry of Energy is expected to take timely action to obtain necessary cabinet approvals for the decisions on financing options and decisions on subsequent procurement of all the relevant projects.

5.2. Procurement of New Renewable Energy and Storage Projects

Project	Completed By	Remarks	Responsibility
Cumulative 180 MW/720 MWh BESS	2027	Expected to be integrated into the system expeditiously by March 2027. Utility scale BESS are preferred and small-scale BESS installations through prosumers may also be considered.	NSO / EDL & LECO with Prosumers / Developer
100 MW/400MWh BESS	2028	To be procured under tendering. Business model to be decided. Procurement to be started in early 2027	NSO / Developer
100 MW Grid connected solar	2028	1-10 MW solar projects	NSO / Developer
10 MW Biomass	2028	SPPA Signed / Pending	NSO / Developer
10 MW Minihydro	2028	SPPA Signed / Pending	NSO / Developer
100 MW Kondachchi Wind power plant	2029	Provisional approval granted	NSO – Project Initiation Developer – Project Execution
60 MW Mannar Wind power plant	2029	Board approval pending	NSO – Project Initiation Developer – Project Execution
300 MW/1200MWh BESS	2029	To be procured under tendering. Business model to be decided. Procurement to be started in early 2028	NSO / Developer

Project	Completed By	Remarks	Responsibility
300 MW Grid connected solar	2029	To be procured under tendering as solar park projects. Procurement to be started in 2027	NSO / Developer
10 MW Biomass	2029	SPPA Pending	NSO / Developer
10 MW Minihydro	2029	SPPA Pending	NSO / Developer
Development stage of 600 MW Pumped Storage Power Plant (Maha) – Detailed Design	2029	The detailed design will be carried out under ADB funding of 2.5 Mn USD	NSO / Consultant

Ministry of Energy is expected to take timely action to obtain necessary cabinet approvals for the decisions on financing options and decisions on subsequent procurement of all the relevant projects.

5.3. Renewable Energy Management System and Smart Metering Systems

5.3.1. Integration of Renewable Energy Management System and SCADA/ EMS Modernization

The project is being implemented as an Engineering, Procurement and Construction (EPC) contract under the NSO. The estimated project cost is USD 12 million, with funding provided by the Asian Development Bank (ADB). The tender for the project closed on 2 July 2026 and is currently undergoing technical evaluation. The key project milestones are presented below.

Activity	Completed By
Bid Evaluation	Oct 2026
Cabinet Approval	Nov 2026
Contract Award & Agreement Signing	Dec 2026
Installation and Integration of the System	June 2028

5.3.2. Smart Metering Systems

50,000 meters in Dehiwala area has been converted to smart meters by quarter 2 of 2026 by EDL. All Rooftop solar PV customers, bulk supply customer meters have been converted to smart meters by LECO. Following projects are being initiated/carried out by EDL and LECO.

Project	Completed By*	Remarks	Responsibility
Conversion of all Rooftop solar PV customer meters, bulk supply customer meters, LV substation meters & boundary meters	2027	Project is funded by ADB and currently preparation of technical specifications is in progress	EDL

Project	Completed By*	Remarks	Responsibility
Conversion of all above 180 units usage ordinary customers	2027	Project is funded by ADB	EDL
Providing smart meters to all customers in transformer areas which have average monthly consumer energy consumption of more than 120 units	2028	Partially completed	LECO
Virtual Power Plant Aggregator Scheme	2027–2028	To enable the aggregation of prosumers and provide enhanced visibility and controllability of distributed energy resources	PUCSL, NSO, EDL, LECO

**Provisional data*

5.4. <u>Demand Management Measures</u>

<table>
<tr><th>Project</th><th>Completed By</th><th>Remarks</th><th>Responsibility</th></tr>
<tr><td>Transition of all 3 phase low voltage consumers to TOU tariff structure</td><td>2026</td><td rowspan="2">According to Section 5.2, subsection 5.2 (f) of the National Tariff Policy, dated 03 March 2026, TOU tariffs are to be progressively introduced for all low-voltage consumers. The regulator, in consultation with the licensees, is instructed to prepare a detailed time-bound action plan to complete the transition.</td><td rowspan="3">PUCSL in consultation with NSO / EDL & LECO</td></tr>
<tr><td>Transition of all single phase low voltage consumers to TOU tariff structure</td><td>TBD</td></tr>
<tr><td>Introduction of special Sunday daytime tariff for electric vehicle charging, industries etc.</td><td>2027</td><td>To be incorporated early facilitating demand shifting of high consumption periods to low consumption periods while reducing curtailments.</td></tr>
</table>

5.5. Transmission Line Projects for Renewable Energy Evacuation

Project	**Completed By**	**Remarks**
Re-Construction of Samanalawewa-Embilipitiya 132kV Transmission Line with Zebra	2028	Project funding needs to be secured and relevant cabinet and other approvals for the procurement are required to be established. NSO shall take initial action to award these projects with the approval of the cabinet. However, considering the practical lead times associated with project development, procurement, and implementation, the actual commissioning of these projects may be deferred to a later year.
Re-Construction of Pannipitiya-Panadura – Matugama 132kV Transmission Line with 2xZebra	2028	
Re-Construction of Laxapana - Wimalasurendra 132kV Transmission Line with Zebra	2028	
Re-Construction of New Laxapana - Balangoda 132kV Transmission Line with Zebra	2028	
Capacity enhancement of 132kV Lynx transmission lines to Zebra - Laxapana Complex	2028	
Vavuniya 220 kV Transmission Development	2028	
Capacity enhancement through Augmentation of Kurunegala (31.5 MVA) & Mannar (2 x 45 MVA) Grid Substations	2028/2029	
Re-Construction of Badulla - Laxapana 132kV Transmission Line with Zebra	2030	
Development of 132/33 kV Grid Substations	2028-2031	
Development of the Northern 400 kV Transmission Network	2030	
Norochcholai – Wariyapola 220 kV Transmission Development	2030	
Development of Colombo City Transmission Network	2030	
Monaragala – Hambantota 220 kV Transmission Development	2031	
New Habarana – Kirindiwela 400 kV Transmission Development	2032	

Ministry of Energy is expected to take timely action to obtain necessary cabinet approvals for the decisions on financing options and decisions on subsequent procurement of all the relevant projects.

5.6. <u>System Strength and Stability Support Measures</u>

5.6.1. Installation of two 75 MVA synchronous condenser units each at New Habarana and Mannar and the 300 MVAr STATCOM facility at the Padukka 220 kV Grid Substation (100 MVAr at stage 1)

With the current implementation progress, the expected timelines for the projects are as follows:

a. Expected Timeline for 75 MVA synchronous condenser at New Habarana:

Activity	Completed By	Remarks
Preparation of technical specifications	Mid 2027	Currently in Progress by NSO
Funding Arrangement	2027	Currently in progress (Funds committed by World Bank)
Project execution and commissioning	2029	Project to be assigned to NTNSP for implementation.

b. Expected Timeline for 75 MVA synchronous condenser at Mannar:

Activity	Completed By	Remarks
Initial project approvals and funding arrangement	2027-2028	Project approval process to be initiated by NSO in 2026.
Project execution and commissioning	2029	Project to be assigned to NTNSP for implementation.

c. Expected Timeline for Stage 1 of STATCOM facility at Padukka:

Activity	Completed By	Remarks
Initial project approvals and funding arrangement	2027-2028	Currently in Progress by NSO (to be funded through World Bank Phase 2 funding)
Project execution and commissioning	2029	Project to be assigned to NTNSP for implementation.

It should be noted that the Long Term Transmission Development Plan 2025-2034 has identified the requirement for the above projects in 2028-2029 period. However, considering the practical lead times associated with project development, procurement, and implementation, the actual commissioning of these projects may be deferred to a later year.

5.6.2. Assess and incorporate synchronous condenser mode operation capabilities at existing and retired major thermal and hydropower generating stations

The initial study for this activity would be carried out by NSO and EGL jointly. The implementation would be carried out by EGL.

Expected Timeline:

Activity	Completed By	Remarks
Project approvals and initial feasibility study	2027	Project approval process to be initiated by NSO in 2026.
Implementation	2028-2030	Project will be executed by EGL.

5.6.3. Ensure that a significant proportion of Battery Energy Storage Systems (BESS) deployed within the power system are equipped with grid forming inverter capabilities.

All utility scale BESS (except for the BESS integrated at consumer level) to be implemented in the future will be required to have grid forming inverter capabilities. The BESS projects which are currently in procurement stage (100MW at Kolonnawa and 10MW x 25 BESS Tender) have this requirement added in the functional specifications.

5.6.4. Develop and implement a comprehensive system strength framework and ancillary services strategy to identify future stability requirements

The initial project approval and Terms of Reference for the project would be prepared by NSO. The development and implementation of the framework would also be carried out by NSO during 2027-2029 period.

5.6.5. Develop and implement a Wide Area Monitoring System (WAMS) including the installation of Phasor Measurement Units (PMUs) at strategically selected transmission substations and critical network nodes

The initial approvals for the project have already been received. Technical study for this activity including preparation of technical specifications would be carried out by NSO. The implementation would be carried out by NTNSP. World Bank has agreed to fund this project through Technical Assistance scheme.

Expected Timeline:

Activity	Completed By	Remarks
Finalizing the funding and Technical Study	2027	Project approvals have already been processed and technical study will commence in 2026.
Implementation	2028	