Public Utilities Commission of Sri Lanka

Public Consultation on Electricity Tariff Revision - January 2025

December 17, 2024

List of Acronyms

CEB	Ceylon Electricity Board
CPC	Ceylon Petroleum Corporation
CBSL	Central Bank of Sri Lanka
MLKR	Million Sri Lankan Rupees
GWh	Giga Watt Hours
MW	Mega Watt
kWh	Kilo Watt Hour
LECO	Lanka Electricity Company Private Limited
BSOB	Bulk Supply Operations Business
BST	Bulk Supply Tariff
BSTA	Bulk Supply Transaction Account
NCRE	Non-Conventional Renewable Energy
GDP	Gross Domestic Product
HFO	Heavy Fuel Oil
DL	Distribution Licensee
TL	Transmission Licensee
OPEX	Operational Expenditure
CAPEX	Capital Expenditure
PPA	Power Purchase Agreement
ROA	Return on Assets
ROE	Return on Equity
AWPLR	Average Weighted Prime Lending Rate
CCPI	Colombo Consumer Price Index
PPIUS	Producer Price Index United States of America
O&M	Operation and Maintenance
BST	Bulk Supply Tariff
IPP	Independent Power Producers
ToU	Time of Use
2024H1	Period of January to June in the year 2024
2025H1	Period of January to June in the year 2025

Table of Contents

1. Background

In terms of the Section 30 of Sri Lanka Electricity Act No. 20 of 2009 and Commission approved "Tariff Methodology - 2021", the CEB was directed to submit the tariff proposal for the first tariff revision of 2025, by November 01, 2024, via Commission's letter (Annex 1) dated October 18, 2024.

Accordingly, the end user and bulk supply tariff proposals by CEB, for the first tariff revision of 2025, were received by the Commission on December 06, 2024 (Annex 2). To proceed with the tariff review process, the Commission requested information and clarifications from CEB (Annex 3) and LECO (Annex 4).

In terms of Section 17(b) of Public Utilities Commission of Sri Lanka Act, No. 35 of 2002, and Section 30(3)(b) of Sri Lanka Electricity Act, No. 20 of 2009, the Commission wishes to consult the stakeholders, on this tariff review.

Accordingly, the stakeholders are hereby requested to provide their views on the matters listed below.

1. Forecasted generation mix and costs for the period of January to June 2025
2. Revenue difference from January to June 2024
3. Forecasted fuel cost
4. Forecasted hydro generation for the period of January to June 2025
5. Forecasted NCRE generation for the period of January to June 2025
6. Forecasted transmission and distribution costs for the period of January to June 2025
7. Proposed Tariff Structure (Rate table attached - Annex 5)
8. Summary of Commission's analysis on the tariff submission

Details of the above matters are discussed in the subsequent sections of this document. Any further analysis by the Commission or further information received from CEB and LECO will be uploaded to the Commission's website (https://www.pucsl.gov.lk/) during the stakeholder consultation period.

All written stakeholder comments on these shall be sent to the Commission on or before January 08, 2025, via email, fax or post. A series of oral consultation sessions will also be carried out provincially to gather stakeholder comments. The schedule of provincial consultation is given below;

1.	Stakeholder consultation – Central Province	in Kandy	on December 27, 2024
2.	Stakeholder consultation – Uva Province	in Monaragala	on December 31, 2024
3.	Stakeholder consultation – Sabaragamuwa Province	in Ratnapura	on January 03, 2025
4.	Stakeholder consultation – Southern Province	in Matara	on January 04, 2025
5.	Stakeholder consultation – North Western Province	in Kurunegala	on January 04, 2025
6.	Stakeholder consultation – North Central Province	in Anuradhapura	on January 05, 2025
7.	Stakeholder consultation – Northern Province	in Jaffna	on January 06, 2025
8.	Stakeholder consultation – Eastern Province	in Batticaloa	on January 08, 2025
9.	Stakeholder consultation – Western Province	in Colombo	on January 10, 2025

2. Consulted topics

2.1 Forecast generation mix and costs for the period of January to June 2025

Generation energy mix and energy cost of each power plant as submitted by CEB, are given below;

Table 1: 2025H1 electricity generation and energy cost

Plant/Complex	Unit	25-Jan	25-Feb	25-Mar	25-Apr	25-May	25-Jun
Mahaweli/Laxapana/Samanala	GWh	353.29	275.25	305.84	356.60	454.21	471.70
	LKR/kWh	-	-	-	-	-	-
Mananr wind	GWh	20.34	21.00	12.18	5.75	42.98	58.88
	LKR/kWh	-	-	-	-	-	-
Sapugaskanda Old 4 x 18 MW	GWh	27.66	26.90	30.32	29.38	18.24	21.72
	LKR/kWh	46.02	46.10	45.76	45.84	47.01	46.38
Sapugaskanda Ext. 8 x 9 MW	GWh	34.83	34.47	38.17	36.94	32.85	30.74
	LKR/kWh	42.38	42.40	42.19	42.26	42.50	42.66
Kelanitissa GT 4 x 17 MW (small GT)	GWh	-	-	-	-	-	-
	LKR/kWh	-	-	-	-	-	-
Kelanitissa GT 1 x 115 MW (GT7)	GWh	-	-	-	-	-	-
	LKR/kWh	-	-	-	-	-	-
Kelanitissa Combined Cycle 1	GWh	78.33	84.57	84.94	84.98	72.25	72.02
	LKR/kWh	40.31	40.25	40.25	40.25	40.37	40.38
Kelanitissa Combined Cycle 2	GWh	-	11.04	29.47	5.43	-	9.40
	LKR/kWh	-	73.93	66.36	68.24	-	68.60
Coal – Puttlam	GWh	518.87	489.89	542.38	524.88	526.10	367.42
	LKR/kWh	20.16	20.20	20.13	20.15	20.27	20.42
New Chunnakam	GWh	10.80	10.69	11.84	11.46	9.36	9.06
	LKR/kWh	42.47	42.49	42.27	42.34	42.81	42.89
Chunnakam & Islands	GWh	0.20	0.20	0.20	0.20	0.20	0.20
	LKR/kWh	88.52	88.52	88.52	88.52	88.52	88.52
BARGE	GWh	35.37	32.66	36.16	34.99	30.62	29.92
	LKR/kWh	42.59	42.80	42.53	42.62	42.99	43.06
30MW Hambantota	GWh	0.43	0.27	0.42	-	0.16	0.71
	LKR/kWh	96.41	108.45	97.06	-	131.66	88.51
20MW Mathugama	GWh	0.51	0.33	0.38	0.01	0.19	1.17
	LKR/kWh	88.63	95.33	92.66	665.57	107.45	82.27
Kerawalapitiya - IPP (Westcoast)	GWh	127.90	133.15	168.44	91.60	35.85	46.33
	LKR/kWh	48.85	48.82	48.73	49.01	49.60	49.24
Sobadhanavi	GWh	-	-	-	-	-	10.08
	LKR/kWh	-	-	-	-	-	65.00
Other renewable (Excluding solar RT)	GWh	92.05	83.44	129.37	102.64	173.72	240.49
	LKR/kWh	18.84	19.16	17.87	18.43	17.04	16.50
Solar Rooftop Generation	GWh	116.56	117.21	128.41	113.60	110.85	105.23
	LKR/kWh	26.47	26.47	26.47	26.47	26.47	26.47
Total Generated Energy	**GWh**	**1,417**	**1,321**	**1,519**	**1,398**	**1,508**	**1,475**
Monthly Energy Cost	**MLKR**	**29,504**	**29,949**	**35,342**	**28,665**	**25,282**	**24,917**

Generation capacity cost of each power plant is given below;

Table 2: 2025H1 electricity generation capacity costs

Plant/Complex	Unit	25-Jan	25-Feb	25-Mar	25-Apr	25-May	25-Jun
Mahaweli	MLKR	400.86	403.20	403.20	409.87	409.87	421.73
Laxapana	MLKR	395.32	395.32	395.32	395.32	395.32	399.85
Samanala	MLKR	261.94	261.94	261.94	261.94	261.94	262.69
Mannar Wind	MLKR	551.71	551.71	551.71	551.71	551.71	551.71
Sapugaskanda Old 4 x 18 MW	MLKR	71.69	71.69	71.69	71.69	71.69	72.52
Sapugaskanda Ext. 8 x 9 MW	MLKR	73.73	73.73	73.73	73.73	73.73	73.73
Kelanitissa GT 4 x 17 MW (small GT)	MLKR	43.81	44.77	44.77	44.77	44.77	44.77
Kelanitissa GT 1 x 115 MW (GT7)	MLKR	78.73	78.73	78.73	78.73	78.73	81.64
Kelanitissa Combined Cycle 1	MLKR	102.73	102.73	102.73	102.73	102.73	104.73
Kelanitissa Combined Cycle 2	MLKR	90.62	70.44	70.44	70.44	90.62	71.36
Coal – Puttlam	MLKR	1,081.26	1,097.66	1,128.96	1,135.23	1,141.49	1,155.93
New Chunnakam	MLKR	29.17	29.17	29.17	29.17	29.17	31.26
Chunnakam & Islands	MLKR	8.77	8.77	8.77	8.77	8.77	8.77
BARGE	MLKR	51.46	51.46	53.12	53.12	53.12	54.79
30MW Hambantota	MLKR	17.48	17.48	17.48	26.10	17.48	17.48
20MW Mathugama	MLKR	11.65	11.65	11.65	11.65	11.65	11.65
Kerawalapitiya - IPP (Westcoast)	MLKR	1,306.71	1,192.96	1,306.31	1,268.52	1,393.59	1,352.99
Sobadhanavi	MLKR	25.00	25.00	25.00	1,198.62	1,237.74	1,198.62
Other renewables	MLKR	-	-	-	-	-	-
TOTAL	MLKR	**4,602.64**	**4,488.39**	**4,634.72**	**5,792.10**	**5,974.11**	**5,916.21**

2.2 Revenue difference from January to September 2024

CEB submitted value for the revenue difference of Transmission Licensee is MLKR 41,234 for the period of January to September 2024. However, calculation/derivation of the number is not submitted.

Actual generation cost for January – June 2024 has been submitted by CEB. The submitted actual generation energy mix and energy cost of each power plant is given below;

Table 3: 2024H1 actual electricity generation and energy cost

Plant/Complex	Unit	24-Jan	24-Feb	24-Mar	24-Apr	24-May	24-Jun
Mahaweli/Laxapana/Samanala	GWh	629.66	305.87	323.42	379.67	399.27	468.46
	LKR/kWh						
Mananr wind	GWh	21.66	22.04	10.60	8.12	29.84	61.60
	LKR/kWh						
Sapugaskanda Old 4 x 18 MW	GWh	11.41	27.64	37.69	30.69	14.26	-
	LKR/kWh	61.64	38.35	48.94	49.10	48.57	-
Sapugaskanda Ext. 8 x 9 MW	GWh	15.25	31.33	34.29	35.76	29.60	18.73
	LKR/kWh	48.99	36.40	45.04	45.01	41.57	41.43
Kelanitissa GT 4 x 17 MW (small GT)	GWh	-	-	-	-	-	-
	LKR/kWh	-	-	-	-	-	-
Kelanitissa GT 1 x 115 MW (GT7)	GWh	-	-	-	20.16	15.47	-

	LKR/kWh	-	-	-	109.11	129.04	-
Kelanitissa Combined Cycle 1	GWh	0.34	4.86	103.81	73.67	71.71	-
	LKR/kWh	100.40	49.55	56.14	62.50	56.61	-
Kelanitissa Combined Cycle 2	GWh	-	-	0.48	32.50	39.81	-
	LKR/kWh	-	-	218.55	82.59	78.22	-
Coal – Puttlam	GWh	321.53	556.13	596.40	484.70	517.73	468.22
	LKR/kWh	20.93	21.16	21.59	21.11	20.83	19.38
New Chunnakam	GWh	4.73	8.58	11.19	9.98	7.13	3.86
	LKR/kWh	50.33	38.06	40.63	41.81	47.26	96.94
Chunnakam & Islands	GWh	0.22	0.21	0.23	0.25	0.24	0.25
	LKR/kWh	108.70	114.11	114.57	114.81	111.40	105.09
BARGE	GWh	25.37	28.53	32.67	37.86	24.90	15.29
	LKR/kWh	49.11	33.57	46.19	46.37	42.69	43.53
30MW Hambantota	GWh	-	-	-	2.64	2.92	0.03
	LKR/kWh	-	-	-	102.71	97.05	412.97
20MW Mathugama	GWh	0.00	-	-	1.90	1.65	0.01
	LKR/kWh	691.37	-	-	104.02	103.54	752.85
Kerawalapitiya - IPP (Westcoast)	GWh	41.86	103.58	160.72	76.40	-	8.31
	LKR/kWh	56.00	42.15	49.03	49.17	-	56.16
Sobadhanavi	GWh	-	-	-	-	10.32	7.22
	LKR/kWh	-	-	-	-	-	-
ACE Embilipitya - 93 MW	GWh	2.59	16.53	2.73	-	-	-
	LKR/kWh	66.22	51.57	57.96	-	-	-
ACE -Matara - 23.75 MW	GWh	1.20	1.89	-	-	-	-
	LKR/kWh	63.36	45.81	-	-	-	-
Other renewable (Excluding solar RT)	GWh	195.38	144.21	83.11	98.20	227.20	234.13
	LKR/kWh	17.78	18.91	14.61	18.90	15.93	16.00
Solar Rooftop Generation	GWh	53.19	62.10	68.30	72.40	62.82	59.84
	LKR/kWh	23.65	25.06	25.67	26.66	26.66	26.66
Total Generated Energy	**GWh**	**1,324**	**1,313**	**1,466**	**1,365**	**1,455**	**1,346**
Monthly Energy Cost	**MLKR**	**17,048**	**25,108**	**35,194**	**33,049**	**29,052**	**16,742**

Actual generation capacity cost of each power plant is given below;

Table 4: 2024H1 actual electricity generation capacity costs

Plant/Complex	Unit	24-Jan	24-Feb	24-Mar	24-Apr	24-May	24-Jun
Mahaweli	MLKR	285.84	237.77	243.35	951.74	325.30	247.34
Laxapana	MLKR	169.52	249.00	266.98	373.16	437.34	311.70
Samanala	MLKR	125.09	230.64	152.51	181.51	187.55	141.17
Mannar Wind	MLKR	36.62	41.09	2,536.02	370.44	47.00	89.23
Sapugaskanda Old 4 x 18 MW	MLKR	33.50	153.39	115.55	68.23	149.10	102.44
Sapugaskanda Ext. 8 x 9 MW	MLKR	34.46	157.78	118.86	70.18	153.36	90.12
Kelanitissa GT 4 x 17 MW (small GT)	MLKR	23.06	19.38	18.76	28.26	20.61	18.53
Kelanitissa GT 1 x 115 MW (GT7)	MLKR	41.43	34.83	30.62	41.62	34.25	33.29
Kelanitissa Combined Cycle 1	MLKR	84.60	407.74	44.67	113.84	46.19	64.11
Kelanitissa Combined Cycle 2	MLKR	42.03	49.90	26.47	32.79	28.98	27.44
Coal – Puttlam	MLKR	681.37	828.59	1,422.04	1,688.13	1,373.68	814.46
New Chunnakam	MLKR	17.61	20.61	25.40	25.05	446.15	67.76

Chunnakam & Islands	MLKR	5.38	7.47	7.63	11.90	23.11	11.14
BARGE	MLKR	17.51	21.36	17.41	26.27	21.44	19.66
30MW Hambantota	MLKR	18.41	22.38	13.26	14.55	15.16	29.09
20MW Mathugama	MLKR	9.56	14.81	8.84	9.70	10.11	19.39
Kerawalapitiya - IPP (Westcoast)	MLKR	1,543.80	1,236.90	(4.52)	(0.17)	316.14	791.92
Sobadhanavi	MLKR	-	-	-	-	-	-
ACE Embilipitya - 93 MW	MLKR	127.45	153.86	22.55	-	-	-
ACE -Matara - 23.75 MW	MLKR	37.52	15.63	-	-	-	-
Other renewables	MLKR	-	-	-	-	-	-
TOTAL	MLKR	**3,334.76**	**3,903.14**	**5,066.38**	**4,007.20**	**3,635.48**	**2,878.78**

The Commission forecast on the revenue difference for January to June 2024

The Commission calculated the revenue difference of Transmission Licensee as per clauses 2.5.3 and 2.5.4 of the Tariff Methodology, which permits only the revenue difference for the period of January to June 2024 to be considered in January 2025 tariff revision. The detailed calculation is given in the Table 5, 6 and 7 below;

Table 5: 2024H1 BST energy rate related revenue difference

2024H1 Actual Generation, Adjusted for Approved Transmission Loss (GWh) [A]	Approved Forecasted Average BST Energy Rate for 2024H1 (LKR/kWh) [B]	Actual Average BST Energy Rate for 2024H1 (LKR/kWh) [C]	Revenue Difference from Energy Rate for 2024H1 (MLKR) [A x (B-C)]
7,995.52	21.75	19.54	17,670.10

Table 6: 2024H1 BST capacity rate related revenue difference

Actual Average Monthly Peak Demand for 2024H1 (MW) [C]	Approved Forecasted BST Capacity Rate for 2024H1 (LKR/MW/Month) [D]	Actual BST Capacity Rate for 2024H1 (LKR/MW/Month) [E]	Revenue Difference from Capacity Rate for 2024H1 (MLKR) [6C x (D-E)/10^6]
2,659	4,737,913.25	3,267,001.00	23,466.93

Table 7: 2024H1 total revenue difference related to BST

Revenue Difference from Energy Rate for 2024H1 (MLKR)	17,670.10
Revenue Difference from Capacity Rate for 2024H1 (MLKR)	23,466.93
Total Revenue Difference for 2024H1 (MLKR)	41,137.03

In addition to the approved costs included in approved Bulk Supply Tariff of Transmission Licensee for the period January to June 2024, the Commission has allowed an additional 8,000 MLKR for the year 2024 for generation cost variations. This amount has been adjusted only in calculating the total cost to be recovered from end user tariff, but not in Bulk Supply Tariff. This amount will be collected by Distribution Licensees over and above their costs and will be transferred to Transmission Licensee in the form of Uniform National Tariff adjustment. Accordingly, 4,000 MLKR for January to June 2024 additional revenue approved will be added to aforementioned MLKR 41,137, resulting MLKR 45,137.

2.3 Forecasted fuel cost

CEB has obtained a liquid fuel price forecast from CPC (Given in Annex 2 – CEB tariff proposal). All fuel prices considered for CEB submission are as follows.

Table 8: CEB considered fuel prices for 2025H1

Fuel Type	Unit	Price for 2025H1
Coal	LKR/kg	47.57
Diesel	LKR/Ltr	275.00
Naptha	LKR/Ltr	146.00
Fuel Oil	LKR/Ltr	179.00

The Commission forecast on the fuel cost

As per the available data on the Sapugaskanda Oil Refinery production cost, the Commission has estimated that the Naptha and Furnace Oil prices can be lower than CPC submitted forecast. Therefore, the thermal generation cost can be lower than the estimated cost, which the Commission will determine upon the submission of CPC data. If the CPC submits costs to the Commission (for Furnace Oil and Naptha) on the basis of calculation adopted in June 2022 (as submitted previously to the Commission), and adjusting to the current crude oil prices and exchange rate, the generation energy cost will be approximately reduced further by LKR 27.6 Billion, with these prices.

It should be noted that CEB has failed to sign fuel supply agreements with CPC despite several directives issued by the Commission. Due to the absence of a fuel supply agreement and due to the fact that the fuel cost is a pass-through cost to the tariff, CPC revises Naptha and Furnace Oil prices without a clear basis and CEB accepts the same.

Further, Heavy Fuel Oil (HFO), which is a byproduct of Sapugaskanda Oil Refinery, is supplied to Sapugaskanda Power Plant of CEB, at the same price as commercial Fuel Oil. 81 million Liters of this Heavy Fuel Oil, having a very minimal commercial value is planned to be supplied to Sapugaskanda Power Plant in the period of January – June 2025, at 179 LKR/Ltr, as per the dispatch schedule submitted by CEB (assuming Refinery produces enough HFO to cater for Sapugaskanda Power Plant).

2.4 Forecasted hydro generation for the period of January to June 2025

CEB has forecasted following hydro conditions for 2025H1 period.

Table 9: CEB hydro forecast for 2025H1

Description	Unit	Forecast for 2025H1
Hydro starting storage on 1st of January	GWh	1,158
Total hydro inflow	GWh	1,786
Total hydro dispatch	GWh	2,217

The Commission forecast on the hydro generation

The Commission analyzed the hydro inflow and generation forecast of CEB and observed that the seasonal variations are different from those of historical actual values. Further, the hydro generation was observed to be under forecasted. Therefore, the Commission proposes an alternative hydro generation forecast given in the table below (detailed report is attached – Annex 6)

Table 10: Commission forecast of hydro dispatch for 2025H1

Description	Hydro Generation (GWh)						
	Jan	Feb	Mar	Apr	May	Jun	Total
CEB Forecast - 2025	353	275	306	357	454	472	2217
Commission Forecast - 2025	356	307	309	352	474	569	2368

2.5 Forecasted NCRE generation for the period of January to June 2025

The summary of CEB NCRE forecast for 2025H1 is shown below.

Table 11: CEB NCRE forecast for 2025H1

NCRE Source	Unit	Generation Forecast for 2025H1
CEB Wind	GWh	161
Solar Rooftop	GWh	692
IPP Wind	GWh	202
Mini hydro	GWh	407
Ground mounted Solar	GWh	135
Biomass/Dendro	GWh	78
Total NCRE Generation	GWh	1,675

The Commission forecast on the NCRE generation

NCRE generation is observed to be under forecasted by CEB. The Commission conducted an alternative NCRE forecast by estimating NCRE capacity additions and typical plant factors for respective months. Alternative NCRE generation forecast is given below. (detailed report is attached – Annex 7)

Table 12: Commission forecast of NCRE for 2025H1

Description	NCRE Generation (GWh)						
	Jan	Feb	Mar	Apr	May	Jun	Total
CEB Forecast - 2025	229	222	270	222	328	405	1675
Commission Forecast - 2025	292	269	293	291	393	435	1973

2.6 Forecasted transmission and distribution cost for the period of January to June 2025

The CEB proposed transmission and distribution *Allowed Revenue* along with LECO distribution *Allowed Revenue* (before Claw-backs) obtained for 2025H1, applying the revenue control formula as per the clauses 3.1.2.8 and 3.2.1 of the Tariff Methodology, are given in the table below.

Table 13: CEB Transmission & Distribution Cost and LECO distribution cost

Description	Unit	Forecast for 2025H1
Transmission Allowed Revenue	MLKR	12,181
Distribution Allowed Revenue – CEB DLs	MLKR	43,718
Distribution Allowed Revenue – LECO DL	MLKR	6,289

The Commission forecast on the Transmission and Distribution costs

In terms of clause 2.3.2.5 of Tariff Methodology, a claw back must be done for CAPEX (capital Expenditure) approved by the Commission and not expensed/capitalized by the Transmission and Distribution licensees.

Transmission and Distribution costs of 2025 will be adjusted through a claw back on approved CAPEX for 2023, in final tariff decision of the Commission.

OPEX (Operational Expenditure) savings of Transmission and Distribution licensees from the Commission approved expenditure could be due to operational efficiency or over budgeting by licensees. Therefore, the claw back of OPEX of 2023 will be considered by the Commission on a fair basis, in final tariff decision of the Commission.

The surplus calculation done by the Commission (Table 15) is before the Transmission and Distribution cost claw back.

2.7 Proposed tariff structure

CEB proposed revenue and cost summary for 2025H1 is given in the table below,

Table 14: CEB Transmission & Distribution Cost and LECO distribution cost

Description		Unit	2025H1 CEB Forecast
Generation	Energy cost	MLKR	173,658
	Capacity cost	MLKR	31,408
Transmission Allowed Revenue		MLKR	12,181
Distribution Allowed Revenue - CEB		MLKR	43,718
Finance Cost		MLKR	7,728
Total Cost		MLKR	268,693
Estimated Revenue at present tariff		MLKR	229,776
Jan - Sept 2024 period revenue difference		MLKR	41,251
Surplus/ (Deficit)		MLKR	2,334

Accordingly, stating that the estimated revenue surplus from above is within the error margin, CEB has proposed to continue with the existing tariff structure (Annex-5).

2.8 Commission's analysis on the tariff submission

The CEB tariff proposal was studied by the Commission with the available data submitted by CEB. The additional data requirements were requested from CEB and LECO. The findings related to each area were described in the previous sections.

Accordingly, the Commission has formulated a scenario considering the findings from the previous sections. (i.e. Revising NCRE and hydro forecast of CEB with the Commission proposed NCRE and hydro forecast as per *Table 10* and *Table 12*). The Scenario analysis summary is shown in the table below.

Table 15: Summary of scenario

Description		Unit	As per CEB Forecast	Commission's scenario with CPC Fuel Prices and adjusted for Commission Proposed NCRE & Hydro forecast
Generation	Energy cost	MLKR	173,658	157,424[(1)]
	Capacity cost	MLKR	31,408	31,408
Transmission Allowed Revenue		MLKR	12,181	12,181[(2)]
Distribution Allowed Revenue	CEB	MLKR	43,718	43,718[(2)]
	LECO	MLKR	6,289	6,289[(2)]
Finance Cost		MLKR	7,728	7,728
Total Cost		MLKR	274,982	258,748
Total Revenue		MLKR	236,065	242,297[(3)]
Revenue Surplus/(Deficit)		MLKR	(38,917)	(16,451)
Revenue Difference for January - September 2024		MLKR	41,251	45,137[(4)]
Revenue Surplus/(Deficit) for Tariff Revision		**MLKR**	**2,334**	**28,686[(5)]**
Possible Tariff Revision Percentage		**%**	**-0.99%**	**-11.84%[(5)]**

Notes:

(1). Considering both NCRE & Hydro forecast corrections as mentioned above

(2). Claw-backs are yet to be done

(3). Sales revenue calculated for Jan-Jun 2025, as per the sales forecasts submitted by all DLs

(4). Only the revenue correction for Jan-Jun 2024 is considered even though CEB has taken Jan-Sep 2024

(5). This surplus is calculated without any adjustment on CPC submitted fuel prices

It should also be noted that the Generation energy costs for the above scenario is determined by manually adjusting dispatch, replacing costly thermal generation, disregarding operational constraints.

3. Social impact of tariff increase

The Commission studied the social impact of tariff increase with respect to electricity supply disconnections carried out by CEB and LECO in recent years (detailed report is attached – Annex 8).

It should be noted that one of the key factors determining supply security is the affordability of electricity prices.

Annex 1

ශ්‍රී ලංකා මහජන උපයෝගිතා කොමිෂන් සභාව
இலங்கைப் பொதுப் பயன்பாடுகள் ஆணைக்குழு
PUBLIC UTILITIES COMMISSION OF SRI LANKA

ඔබේ අංකය உமது இல. Your No.	අපේ අංකය எமது இல. Our No.	දිනය திகதி Date
	PUC/E/Tariff/01	October 18, 2024

Mr. K. G. R. F. Comester,
General Manager,
Ceylon Electricity Board,
No. 50, Sir Chittampalam A. Gardinar Mw.,
Colombo – 02.

First Electricity Tariff Revision - 2025

Reference is made to the CEB letter (Ref: DGM(CS&RA)/TRF/Trf 2024) dated September 09, 2024, and the Commission letter (Ref: PUC/E/Tariff/01) dated September 13, 2024, on the Third Electricity Tariff Revision – 2024, and the Commission letter (Ref: PUC/E/Tariff/01) dated July 15, 2024, with the decision on Second Electricity tariff revision for 2024.

As communicated by CEB through the above letter, the tariff submission for the period of October to December – 2024 has not yet been submitted to the Commission.

Further, it should be noted that the Second Electricity tariff revision for 2024 was carried out considering the submissions made for the forecast period until December 31, 2024. Accordingly, the next tariff revision becomes mandatory by January 1, 2025. Therefore, you are hereby required to make a tariff submission, as per the Section 30(2) of the Sri Lanka Electricity Act No. 20 of 2009, considering the year 2025. The submission shall be received by the Commission, by November 1, 2024, to ensure the implementation of revised tariff effective from January 1, 2025.

Damitha Kumarasinghe
Director General

06.වන මහල, ලංකා බැංකු වෙළඳ කුළුණ,
28. ශාන්ත මයිකල් පාර, කොළඹ 03.

06 ஆவது மாடி, இலங்கை வங்கி வர்த்தகக் கோபுரம்,
28, சென் மைக்கல் வீதி, கொழும்பு 03.

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ලංකා විදුලිබල මණ්ඩලය
இலங்கை மின்சார சபை
CEYLON ELECTRICITY BOARD

Your ref: My ref: DGM(CS&RA)/TRF/Trf. 2025 Date: December 6, 2024

Director General,
Public Utilities Commission of Sri Lanka,
6th Floor, BOC Merchant Tower,
No.28, St, Michael's Road,
Colombo 3.

Dear Sir,

First Electricity Tariff Revision 2025

This has reference to the PUCSL letter No. PUC/E/Tariff/01 dated 2024-10-18 regarding the above subject.

Accordingly, the tariff revision proposal for the first half of the year 2025 is submitted as Annex I. Additionally, the Bulk Supply Tariff (BST) for the same is attached as Annex II.

The salient points of the tariff revision proposal are explained below.

1. Generation Forecast for the first half 2025 (1H 2025)

The energy generation for 1H 2025 was estimated based on the actual 2024 generation and the growth predictions. The total net generation for the 1H 2025 has been estimated as 8,636.7 GWh and the 2025 generation dispatch forecast has been prepared for the same. The monthly net generation forecast for the year 2025 is as follows.

Table 1: Forecasted Net Generation for 1H 2025

2025	Jan	Feb	Mar	Apr	May	Jun	Total
Forecast Net Gen. (GWh)	1,417.0	1,320.9	1,518.3	1,398.2	1,507.4	1,474.8	**8,636.7**

2. Dispatch

The generation dispatch plan was updated to reflect the latest hydro storage levels, boosted by significant inflows from recent deep depression and cyclonic conditions. Additionally, the Meteorological Department's December weather forecast for December 2024 to February 2025 (Annex III) was considered. With improved initial hydro storage, increased hydro generation has been allocated for the early dry period, while managing reservoir drawdowns to reserve capacity for the next monsoon.

The annual maintenance outage schedule prepared with the coordination of the respective power plants has been reviewed and used to determine the dispatch forecast preparation. A Level C maintenance for

Unit 3 of Lakvijaya Power Plant, requiring a 30-day outage, is planned for June, 2025. A Generator Major Inspection for KCCP2 is planned for 8 weeks from mid-April 2025. The Sobadhanavi IPP Thermal Plant (312 MW) will commence commercial operation in combined cycle mode from April 2025.

Accordingly in first half of 2025, approximately 2,216.9 GWh of energy is expected from hydro, while thermal and other renewable energy sources are anticipated to contribute 4,745.0 GWh and 1,674.7 GWh, respectively. The expected hydro inflow is estimated as 1,786.1 GWh.

3. Sales Forecast

The sales forecast was prepared based on the net generation and transmission and distribution losses. Accordingly, the total estimated sales for 1H 2025 is 7,937.1 GWh. The share of sales to LECO is taken as 851.3 GWh from the 33 kV boundary. Please refer the table 2 below.

Table 2: Sales forecast for 2025

2025	CEB End User Customers (Nos.)	CEB End User Sales (GWh)	LECO 33 kV Sales (GWh)	Total Sales (GWh)
January	7,168,747	1,157.7	145.0	1,302.7
February	7,177,879	1,079.5	135.7	1,215.1
March	7,186,141	1,250.5	145.0	1,395.6
April	7,194,075	1,145.0	140.3	1,285.3
May	7,200,300	1,239.3	145.0	1,384.3
June	7,207,597	1,213.7	140.3	1,354.1
Total	-	**7,085.7**	**851.3**	**7,937.1**

4. Revenue

The forecasted revenue for both CEB and LECO has been calculated, giving due consideration to the transfer price for bulk sales from CEB to LECO. The transfer price, provided by LECO, is taken as 26.14 LKR/kWh for the first half of 2025.The total estimated revenue for 1H 2025 from the existing tariff is LKR 229.7 billion.

5. Expenditure

The existing composite Power Purchase Agreement outlines the pricing for capacity and energy transactions between CEB's Generation and Transmission Divisions, while separate agreements set prices for energy sold by Independent Power Producers (IPPs) and Small Power Producers (SPPs). In CEB Thermal Power Plants, the Energy Price covers startup expenses, variable O&M, and fuel costs based on contractual fuel consumption rates. IPP and SPP energy costs are recovered through their respective PPAs. Energy costs for CEB's hydro and wind generation are considered zero. Expenditure estimates account for actual or tendered fuel prices at CEB's boundary, with liquid fuel pricing beyond CEB's control. Coal pricing reflects actual values. Fuel prices, exchange rates, and VAT revisions have been updated as of December, 2024 and according to the letter of Managing Director, CPC letter no. FD/DGM/2024/02/CEB dated 2024-12-05 (Annex IV). Please refer the table 3 below.

Table 3: Fuel Prices and Exchange rates used in Tariff Revision 1H 2025

	Description	1H 2025
1	Auto Diesel (Rs./l)	275.00
2	Furnace oil (Rs./l)	179.00
3	Naphtha (Rs./l)	146.00
4	Coal (Rs./kg)	47.57
5	Ex. Rate (Rs./USD)	294.97

CEB plant capacity costs cover fixed O&M, services by CEB and Generation HQ, allocated based on installed capacity. IPP and SPP capacity costs are recovered through their PPAs. Capacity and energy costs are calculated accordingly. For CEB plants, major CAPEX is managed via monthly bank loans, easing the impact of capital-intensive projects on tariff. This strategy, approved in the 2024 Tariff Decision, spreads costs over time to moderate immediate tariff increases.

Total Transmission and Distribution allowed revenue excluding the finance cost component are calculated based on the tariff filing approved by the PUCSL by the decision dated 2024-07-15 and provisional BST decision document of PUCSL dated 2024-09-19.

It is important to note that CEB has informed PUCSL of certain operational errors identified in the transmission revenue filing templates during the previous tariff submission. While the Commission is yet to address these discrepancies, the allowed revenue for the Transmission Licensee in 2024 was determined based on the latest actual expenses available at that time. However, this decision has resulted in an approved transmission allowed revenue insufficient to cover expenses. Accordingly, the allowed revenue for the Transmission Licensee for the first half of 2025 has been estimated as LKR 12,181million.

Similarly, the approved allowed revenue of Distribution Licensees for 2024 has been indexed and updated for 2025 and the distribution cost including adjustment of allowed revenue for CEB for 1H 2025 is as follows.

Table 4: Distribution Costs for 1H 2025

Description	Unit	DL1	DL2	DL3	DL4
Distribution Allowed Revenue	MLKR	7,914	10,962	6,284	5,793
Retail Service Cap	LKR/Customer	5,095	2,449	3,541	3,352
Total Distribution Cost	**MLKR**	13,009	13,989	8,937	7,783

Furthermore, the finance cost has been updated as per the latest Average Weighted Prime Lending Rate (AWPLR) of 9.3%. The finance cost for the 1H 2025 has been estimated as LKR 7,728 million.

6. Conclusion

As per Clause 5.2 of PUCSL's Tariff Methodology, end-user tariffs are determined based on CEB's revenue requirements. CEB analyzed factors such as current tariffs, fuel availability, future prices, hydro inflows, plant schedules, interest rates, economic recovery, energy demand, transmission and distribution adjustments, and government policies to develop the BST and tariff proposal.

The summary of expenditure for 2024 considered for the tariff revision is tabulated below.

Table 5: Summary of Expenditures considered for 1H 2025

Description	**Unit**	**2025 1H**	**Source**
Generation - Energy Cost	MLKR	173,658	BST 1H 2025
Generation - Capacity Cost	MLKR	31,408	-do-
Transmission Allowed Revenue	MLKR	12,181	As above
Finance Cost	MLKR	7,728	Latest forecast
Distribution Allowed Revenue	MLKR	43,718	As above
Total Cost	**MLKR**	**268,693**	-
Estimated Revenue at present tariffs	**MLKR**	**229,776**	Latest Forecast
Jan – Sept 2024 period revenue difference	**MLKR**	**41,251**	Annex V
Surplus/(Deficit)	**MLKR**	**2,334**	-

Based on the above analysis, a surplus of LKR 2,334 million has been estimated for 1H 2025 warranting a tariff reduction of 1.02 %. Any variations in the estimate, whether an excess or a shortfall, will be accounted for in the Bulk Supply Transaction Account (BSTA) and considered in the next tariff revision.

However, considering the inherent uncertainties associated with hydroelectric generation predictions for the year 2025, the projected surplus must be evaluated with caution. Therefore, it is prudent to recognize that the indicated surplus falls well within the margin of estimation error.

In light of this, and to ensure financial and operational stability while avoiding potential risks to the reliability of electricity supply, CEB proposes to maintain the prevailing tariff structure for the first six months in 2025.

The Board approved the tariff proposal for the first half of 2025, is hereby submitted to the Commission for its approval and subsequent implementation, please.

Yours faithfully
CEYLON ELECTRICITY BOARD

Eng. K.G.R.F. Comester
General Manager
Ceylon Electricity Board

Eng. K. G. R. F. Comester
General Manager
Ceylon Electricity Board

Copy to:

1. *Secretary to the Treasury* - *fi & na pl.*
2. *Chairman, CEB* - *fi pl.*
3. *Addl. GM (CS)* - *fi pl.*
4. *FM, CEB* - *fi pl.*

Annex I

			Existing tariff to be continued for the first 6 months of 2025			
EFFECTIVE FROM (for each 30 - day billing period)			2025-01-01			
DOMESTIC						
			Energy Charge (Rs./kWh)		**Fixed Charge (Rs./mth)**	
Consumption 0 - 60 kWh per month						
Block 1 : 0 - 30 kWh			6.00		100.00	
Block 2 : 31 - 60 kWh			9.00		250.00	
Consumption above 60 kWh per month						
Block 1 : 0 – 60 kWh			15.00		N/A	
Block 2 : 61 – 90 kWh			18.00		400.00	
Block 3 : 91 – 120 kWh			30.00		1,000.00	
Block 4 : 121 – 180 kWh			42.00		1,500.00	
Block 5 : 181 and above			65.00		2,000.00	
Optional Time of Use (ToU) Electricity Tariff for Dom. Consumers						
Day (05:30 – 18:30 hrs)			56.00		2,000.00	
Peak (18:30 – 22:30 hrs)			72.00			
Off Peak (22:30 – 05:30 hrs)			24.00			
RELIGIOUS & CHARITABLE INSTITUTIONS						
Consumption 0 - 180 kWh per month						
Block 1 : 0 – 30 kWh			6.00		100.00	
Block 2 : 31 – 90 kWh			6.00		250.00	
Block 3 : 91 – 120 kWh			10.00		300.00	
Block 4 : 121 – 180 kWh			20.00		1,200.00	
Block 5 : 181 kWh and above			30.00		1,600.00	
OTHER CONSUMER CATEGORIES			**Industrial / Hotel**		**General Purpose / Government**	
Volume differentiated monthly consumption			**IP/H 1-1 (≤ 300 kWh/mth)**	**IP/H 1-2 (> 300 kWh/mth)**	**GP/GV 1-1 (≤ 180 kWh/mth)**	**GP/GV 1-2 (> 180 kWh/mth)**
Rate 1 Supply at 400/230 V Contract demand <= 42 kVA	Energy Charge (Rs. /kWh)		10.00	16.00	26.40	34.40
	Fixed Charge (Rs./mth)		300.00	1,000.00	600.00	1,500.00
Rate 2 Supply at 400/230 V Contract demand > 42 kVA	Energy Charge (Rs./kW)	Day (05:30 – 18:30 hrs)	20.50		38.25	
		Peak (18:30 – 22:30 hrs)	30.50		46.75	
		Off Peak (22:30 – 05:30 hrs)	18.00		31.45	
	Demand Charge (Rs./kVA)		1,500.00		1,500.00	
	Fixed Charge (Rs./mth)		5,000.00		5,000.00	
Rate 3 Supply at 11 kV & above	Energy Charge (Rs./kW)	Day (05:30 – 18:30 hrs)	19.50		37.40	
		Peak (18:30 – 22:30 hrs)	29.50		45.90	
		Off Peak (22:30 – 05:30 hrs)	17.00		30.60	
	Demand Charge (Rs./kVA)		1,400.00		1,400.00	
	Fixed Charge (Rs./mth)		5,000.00		5,000.00	
STREET LIGHTING						
Street Lighting (Rs./kWh)			45.00			
EV CHARGING OF CEB CHARGING STATIONS			**DC Fast Charging (Rs./kWh)**		**Level 2 AC Ch. (Rs./kWh)**	
Day (05:30 – 18:30 hrs)			87.00		70.00	
Peak (18:30 – 22:30 hrs)			111.00		90.00	
Off Peak (22:30 – 05:30 hrs)			53.00		40.00	
AGRICULTURE - Optional Time of Use (ToU) Electricity Tariff			**Energy Charge (Rs./kWh)**		**Fixed Charge (Rs./mth)**	
Rate 1 Supply at 400/230V Contract demand <= 42 kVA		Day (05:30 – 18:30 hrs)	18.00		1,000.00	
		Peak (18:30 – 22:30 hrs)	35.00			
		Off Peak (22:30 – 05:30 hrs)	8.00			

4

Bulk Supply Tariff Jan - June 2025 Index

Capacity Charge

Month	Unit	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Capacity Charge							
Generation capacity	SLR/MW	1,724,634.86	1,626,428.95	1,656,598.21	2,147,803.12	2,223,833.11	2,302,658.48
Transmission	SLR/MW	696,009.29	673,083.49	663,924.01	688,783.26	691,438.53	722,953.14
Bulk Supply Service	SLR/MW	549,262.65	525,572.35	513,449.78	523,877.40	520,605.92	622,871.78
BST (C)	**SLR/MW**	**2,969,906.80**	**2,825,084.79**	**2,833,972.00**	**3,360,463.77**	**3,435,877.56**	**3,648,483.40**

BST (C) 6-Month Weighed average	**SLR/MW**	**3,171,933.97**

Energy Charge

Month	Unit	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Block1							
Transmission Loss Factor B1	%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%
Generation energy Cost B1	SLR/kWh	21.47	23.37	24.00	21.13	17.29	17.42
BST (E1)	**SLR/kWh**	**22.19**	**24.17**	**24.81**	**21.85**	**17.88**	**18.01**
Block 2							
Transmission Loss Factor B2	%	4.34%	4.34%	4.34%	4.34%	4.34%	4.34%
Generation energy Cost B2	SLR/kWh	27.90	30.39	31.20	27.47	22.48	22.64
BST (E2)	**SLR/kWh**	**29.12**	**31.70**	**32.55**	**28.67**	**23.45**	**23.62**
Block 3							
Transmission Loss Factor B3	%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%
Generation energy Cost B3	SLR/kWh	12.88	14.02	14.40	12.68	10.37	10.45
BST (E3)	**SLR/kWh**	**13.19**	**14.36**	**14.74**	**12.99**	**10.62**	**10.70**

BST (E1) 6-Month Weighed average	**SLR/kWh**	**21.43**
BST (E2) 6-Month Weighed average	**SLR/kWh**	**28.12**
BST (E3) 6-Month Weighed average	**SLR/kWh**	**12.74**

E1 - Day
E2 -peak
E3 -off peak

Annex (4)

Generation Capacity Cost

Index

Remarks :Added Sobadhanavi

Item\Month	Unit	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
System Coincidental Peak demand	MW	2669	2760	2798	2697	2686	2569

Capacity Payment

Plant\Month	Unit	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Mahaweli	Mn. SLR	400.9	403.2	403.2	409.9	409.9	421.7
Laxapana	Mn. SLR	395.3	395.3	395.3	395.3	395.3	399.8
Samanala	Mn. SLR	261.9	261.9	261.9	261.9	261.9	262.7
Mannar Wind	Mn. SLR	551.7	551.7	551.7	551.7	551.7	551.7
DSP1	Mn. SLR	71.7	71.7	71.7	71.7	71.7	72.5
DSP2	Mn. SLR	73.7	73.7	73.7	73.7	73.7	73.7
GT16	Mn. SLR	43.8	44.8	44.8	44.8	44.8	44.8
GT07	Mn. SLR	78.7	78.7	78.7	78.7	78.7	81.6
CCKP	Mn. SLR	102.7	102.7	102.7	102.7	102.7	104.7
CCKP 02	Mn. SLR	90.6	70.4	70.4	70.4	90.6	71.4
CPUT	Mn. SLR	1,081.3	1,097.7	1,129.0	1,135.2	1,141.5	1,155.9
DNCHU	Mn. SLR	29.2	29.2	29.2	29.2	29.2	31.3
Island Gen	Mn. SLR	8.8	8.8	8.8	8.8	8.8	8.8
BARGE	Mn. SLR	51.5	51.5	53.1	53.1	53.1	54.8
30MW Hambantota	Mn. SLR	17.5	17.5	17.5	26.1	17.5	17.5
20MW Mathugama	Mn. SLR	11.7	11.7	11.7	11.7	11.7	11.7
CCKW	Mn. SLR	1,306.7	1,193.0	1,306.3	1,268.5	1,393.6	1,353.0
SGPS (100MW)	Mn. SLR	0.0	0.0	0.0	0.0	0.0	0.0
DEMB	Mn. SLR	0.0	0.0	0.0	0.0	0.0	0.0
DMAT	Mn. SLR	0.0	0.0	0.0	0.0	0.0	0.0
Sobadhanavi	Mn. SLR	25.0	25.0	25.0	1,198.6	1,237.7	1,198.6
RENW	Mn. SLR	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	**Mn. SLR**	**4,602.6**	**4,488.4**	**4,634.7**	**5,792.1**	**5,974.1**	**5,916.2**
Depreciation	**Mn. SLR**						
ROE	**Mn. SLR**						
Generation Capacity cost	**Mn. SLR**	**4,602.6**	**4,488.4**	**4,634.7**	**5,792.1**	**5,974.1**	**5,916.2**

Generation Capacity cost

	Unit	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Generation Capacity cost	**SLR/MW**	**1,724,634.86**	**1,626,428.95**	**1,656,598.21**	**2,147,803.12**	**2,223,833.11**	**2,302,658.48**

Energy price and Energy generated in each plant

Plant\Month	Unit	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Mahaweli	GWh	353.291	275.247	305.838	356.599	454.208	471.702
	SLR/kWh						
Laxapana	GWh						
	SLR/kWh						
Samanala	GWh						
	SLR/kWh						
Mannar wind	GWh	20.345	20.999	12.183	5.748	42.976	58.876
	SLR/kWh						
DSP1	GWh	27.662	26.905	30.320	29.376	18.239	21.719
	SLR/kWh	46.02	46.10	45.76	45.84	47.01	46.38
DSP2	GWh	34.828	34.474	38.167	36.936	32.853	30.736
	SLR/kWh	42.38	42.40	42.19	42.26	42.50	42.66
GT16	GWh	0.000	0.000	0.000	0.000	0.000	0.000
	SLR/kWh	0.00	0.00	0.00	0.00	0.00	0.00
GT07	GWh	0.0	0.0	0.0	0.0	0.0	0.0
	SLR/kWh	0.00	0.00	0.00	0.00	0.00	0.00
CCKP	GWh	78.3	84.6	84.9	85.0	72.2	72.0
	SLR/kWh	40.31	40.25	40.25	40.25	40.37	40.38
CCKP 02	GWh	0.0	11.0	29.5	5.4	0.0	9.4
	SLR/kWh	0.00	73.93	66.36	68.24	0.00	68.60
CPUT	GWh	518.9	489.9	542.4	524.9	526.1	367.4
	SLR/kWh	20.16	20.20	20.13	20.15	20.27	20.42
DNCHU	GWh	10.8	10.7	11.8	11.5	9.4	9.1
	SLR/kWh	42.47	42.49	42.27	42.34	42.81	42.89
Island Gen	GWh	0.20	0.20	0.2	0.2	0.2	0.2
	SLR/kWh	88.52	88.52	88.52	88.52	88.52	88.52
BARGE	GWh	35.4	32.7	36.2	35.0	30.6	29.9
	SLR/kWh	42.6	42.8	42.5	42.6	43.0	43.1
30MW Hambantota	GWh	0.430	0.274	0.417	0.000	0.157	0.707
	SLR/kWh	96.41	108.45	97.06	0.00	131.66	88.51
20MW Mathugama	GWh	0.515	0.327	0.379	0.010	0.193	1.169
	SLR/kWh	88.63	95.33	92.66	665.57	107.45	82.27
CCKW	GWh	127.9	133.1	168.4	91.6	35.9	46.3
	SLR/kWh	48.85	48.82	48.73	49.01	49.60	49.24
SGPS (100MW)	GWh	0.00	0.00	0.00	0.00	0.00	0.00
	SLR/kWh	0.00	0.00	0.00	0.00	0.00	0.00
DEMB	GWh	0.0	0.0	0.0	0.0	0.0	0.0
	SLR/kWh	0.0	0.00	0.00	0.00	0.00	0.00
DMAT	GWh	0.0	0.000	0.000	0.000	0.000	0.000
	SLR/kWh	0.00	0.000	0.000	0.000	0.000	0.000
Sobadhanavi	GWh	0.00	0.00	0.00	0.00	0.00	10.08
	SLR/kWh	0.00	0.00	0.00	0.00	0.00	65.00
RENW	GWh	92.052	83.441	129.374	102.644	173.723	240.490
	SLR/kWh	18.84	19.16	17.87	18.43	17.04	16.50
Solar Rooftop Generation	GWh	116.557	117.206	128.413	113.596	110.850	105.235
	SLR/kWh	26.47	26.47	26.47	26.47	26.47	26.47
TOTAL generated energy	**GWh**	**1,417.150**	**1,321.070**	**1,518.510**	**1,398.450**	**1,507.581**	**1,475.051**
Energy Cost	SLR	29,503,947,841	29,948,771,456	35,341,638,050	28,665,145,482	25,281,935,287	24,916,629,562
Energy Cost	SLR Million	29,504	29,949	35,342	28,665	25,282	24,917
		29,504	29,949	35,342	28,665	25,282	24,917

Total Energy cost for six-months	LKR Million	173,658.07
Total energy dispatch for six months	GWh	8,637.811
Six-month average energy cost	LKR/kWh	20.10
loss adjusted six-month average energy cost	LKR/kWh	20.79

Loss factor %		[redacted]	Loss Calculation Prepared by CS as at April 27, 2024
		96.69	
		97.18	

Notes

TOU enregy ratio is chaged as follows. These ratios were calculated using actual sales to DLs from May 2018 to April 2019 considering a consistent period of 12 months.

TOU Factors	Day	Peak	Offpeak
	58.0%	19.7%	22.3%

Capacity Transmission tariff (TR) & Bulk Supply and Operations Business Tariff (BSS)

Index

Item	Unit	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Transmission system allowed revenue *	Mn. SLR	1,681	1,681	1,681	1,681	1,681	1,681
BSOB allowed revenue *	Mn. SLR	113	113	113	113	113	113
[illegible]							
Long / Short Term Interest Account	Mn. SLR	566	550	536	513	498	700
Overdraft Interest Account	Mn. SLR	500	500	500	500	500	500
Debenture Interest Account	Mn. SLR	156	156	156	156	156	156
Lease interest Account	Mn. SLR	2	2	2	2	2	2
Delayed Interest on IPP Payments	Mn. SLR	20	20	20	20	20	20
Delayed Interest on NCRE Payments	Mn. SLR	50	50	50	50	50	50
TL Additional OPEX Requirement							
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TL Additional CAPEX Requirement							
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
System Coincidental Peak demand	MW	2669	2760	2798	2697	2686	2569

Month	Unit	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Capacity Transmission tariff (TR)	**SLR/MW**	**696,009**	**673,083**	**663,924**	**688,783**	**691,439**	**722,953**
Bulk Supply and Operations Business Tariff (BSS)	**SLR/MW**	**549,263**	**525,572**	**513,450**	**523,877**	**520,606**	**622,872**

Transmission Losses Factor

Block 1

Month	Unit	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Forecasted transmission losses	GWh	28	26	30	28	30	29
Total forecasted energy supplied	GWh	822	766	881	811	874	856
Forecasted TLF	**%**	**3.40%**	**3.40%**	**3.40%**	**3.40%**	**3.40%**	**3.40%**

Block 2

Month	Unit	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Forecasted transmission losses	GWh	12	11	13	12	13	13
Total forecasted energy supplied	GWh	279	260	299	275	297	291
Forecasted TLF	**%**	**4.34%**	**4.34%**	**4.34%**	**4.34%**	**4.34%**	**4.34%**

Block 3

Month	Unit	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Forecasted transmission losses	GWh	8	7	8	8	8	8
Total forecasted energy supplied	GWh	316	295	339	312	336	329
Forecasted TLF	**%**	**2.41%**	**2.41%**	**2.41%**	**2.41%**	**2.41%**	**2.41%**

Capacity Transmission tariff (TR)	SLR	1,857,481,176.39	1,857,481,176.39	1,857,481,176.39	1,857,481,176.39	1,857,481,176.39	1,857,481,176.39
Bulk Supply and Operations Business Tariff (BSS)	SLR	1,465,849,727.51	1,450,400,667.47	1,436,494,681.37	1,412,770,111.93	1,398,556,292.49	1,600,342,473.05

avg tx loss factor	%	3.38%

ENERGY DISPATCH FORECAST - GWh- 2025													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Total Net Generation	**1417**	**1321**	**1518**	**1398**	**1507**	**1475**	**1534**	**1537**	**1464**	**1495**	**1424**	**1462**	**17553**
Total Net Generation/day	45.7	47.2	49.0	46.6	48.6	49.2	49.5	49.6	48.8	48.2	47.5	47.2	
NCRE Generation	**229.0**	**221.6**	**270.0**	**222.0**	**327.5**	**404.6**	**366.0**	**416.7**	**426.1**	**374.0**	**310.8**	**334.9**	**3903**
No. of days	31.0	28.0	31.0	30.0	31.0	30.0	31.0	31.0	30.0	31.0	30.0	31.0	**365**
Generation (Centrally dispatch)	1188.0	1099.3	1248.4	1176.3	1179.9	1070.2	1167.8	1120.7	1038.2	1120.7	1113.1	1127.2	
Reqd. Generation/day(Centraly)	38.3	39.3	40.3	39.2	38.1	35.7	37.7	36.2	34.6	36.2	37.1	36.4	
IPP Thermal Generation													
Sobadanavi	0.0	0.0	0.0	0.0	0.0	10.1	13.5	0.7	0.6	10.9	7.3	16.1	**59.4**
WCPP	127.9	133.1	168.4	91.6	35.9	46.3	62.4	63.8	29.9	51.8	90.6	122.4	**1024.3**
TOTAL IPP	**127.9**	**133.1**	**168.4**	**91.6**	**35.9**	**56.4**	**76.0**	**64.5**	**30.5**	**62.7**	**97.9**	**138.6**	**1083.6**
CEB Thermal Generation													
LAKVIJAYA1	157.3	163.3	180.8	175.0	175.4	169.7	28.9	175.4	169.6	173.0	167.4	175.4	
LAKVIJAYA2	180.8	163.3	180.8	175.0	175.4	169.7	175.4	175.4	169.6	0.0	0.0	175.4	**5591.0**
LAKVIJAYA3	180.8	163.3	180.8	175.0	175.4	28.0	175.4	175.4	169.6	173.0	167.4	175.4	
SAPU B	34.8	34.5	38.2	36.9	32.9	30.7	33.2	33.1	24.9	33.7	33.7	34.5	**401.1**
SAPU A	27.7	26.9	30.3	29.4	18.2	21.7	17.2	21.8	15.3	17.8	23.4	24.3	**274.0**
BARGE	35.4	32.7	36.2	35.0	30.6	29.9	32.6	33.4	27.7	31.0	30.3	33.6	**388.3**
Uthuru Jannanee	10.8	10.7	11.8	11.5	9.4	9.1	9.6	9.4	7.1	9.5	9.2	10.3	**118.4**
KCCP_Naptha	78.3	84.6	84.9	85.0	72.2	72.0	73.0	77.4	60.7	69.8	78.4	0.0	**836.4**
KCCP_Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
GT7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
SMALL_GT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
KCCPS 2	0.0	11.0	29.5	5.4	0.0	9.4	19.9	8.2	6.1	24.5	18.2	36.1	**168.3**
Dakanu Jananee	0.4	0.3	0.4	0.0	0.2	0.7	0.2	0.3	0.1	0.3	0.1	0.1	**3.2**
Matugama-CEB	0.5	0.3	0.4	0.0	0.2	1.2	1.2	0.3	0.1	0.3	0.1	0.7	**5.3**
Total CEB Thermal Generation	**706.8**	**690.8**	**774.1**	**728.1**	**689.8**	**542.1**	**566.6**	**710.0**	**650.7**	**533.0**	**528.3**	**665.6**	**7785.9**
Prospective Gen. / Energy shortfall													
Total Thermal Generation	**834.7**	**824.0**	**942.5**	**819.7**	**725.6**	**598.5**	**642.5**	**774.6**	**681.2**	**595.7**	**626.2**	**804.2**	**8869.5**
Hydro Gen Reqd.	**353.3**	**275.2**	**305.8**	**356.6**	**454.2**	**471.7**	**525.2**	**346.1**	**357.0**	**525.0**	**486.9**	**323.0**	**4780.1**
Deficit	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Net Generation excluding deficit	**1417**	**1321**	**1518**	**1398**	**1507**	**1475**	**1534**	**1537**	**1464**	**1495**	**1424**	**1462**	**17553**
Inflow	275.9	166.3	156.0	271.7	447.3	468.9	482.0	359.3	449.3	549.6	531.6	345.6	4503.4
Drawdown from reservoirs	-77.4	-108.9	-149.8	-84.9	-7.0	-2.8	-43.3	13.1	92.2	24.6	44.7	22.6	
STARTING STORAGE	1158	1081	972	822	737	730	727	684	697	789	814	859	
Month End Storage	1081	972	822	737	730	727	684	697	789	814	859	881	
% Storage	0.8	0.8	0.6	0.6	0.6	0.6	0.5	0.5	0.6	0.6	0.7	0.7	

Annex III

කාලගුණ විද්‍යා දෙපාර්තමේන්තුව
வளிமண்டலவியல் திணைக்களம்
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No SF-2024-12

Seasonal, Monthly and weekly Rainfall Forecasts for December 2024-February 2025

Issued on 2nd December 2024 by Seasonal Forecasting Division of the Department of Meteorology, Sri Lanka.

This consensus Climate Outlook for December 2024 to February 2025 season over Sri Lanka has been developed through an expert assessment of the prevailing global climate conditions influencing the South Asian climate and seasonal forecasts from different climate models around the world. ENSO-neutral conditions are present. Equatorial sea surface temperatures (SSTs) are near-to-below-average in the central and eastern Pacific Ocean. La Niña is favored to emerge in October-December (57% chance) and is expected to persist through January-March 2025.The Indian Ocean Dipole (IOD) index for the week ending 24 November was −0.54 °C, having been below the negative IOD threshold (–0.4 °C) since mid-October. Careful consideration is also given to other regional and global factors as well as the intraseasonal variability of the region that can affect the rainfall and temperature patterns over the country.

Seasonal Rainfall Forecast for December–February 2024/25 (DJF)

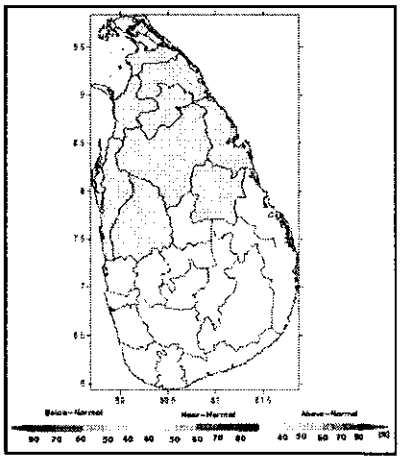


Fig 1: Consensus Probabilistic Monthly rainfall forecast for DJF 2024/25

There is a possibility for having near or slightly above normal rainfall over Northern, North-central and Northwestern provinces and in Trincomalee district and no signal for remaining areas of the country during DJF 2024/25 as a whole. In addition to that development of the

synoptic scale systems such as wavy type disturbances, lows, depressions and cyclones are also possible during the season particularly during December and January. If so rainfall can increase **(Fig.01).**

Monthly Rainfall Forecasts for December 2024, January and February 2025

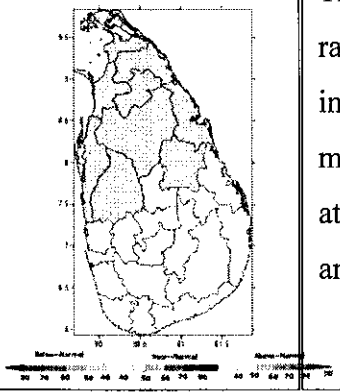
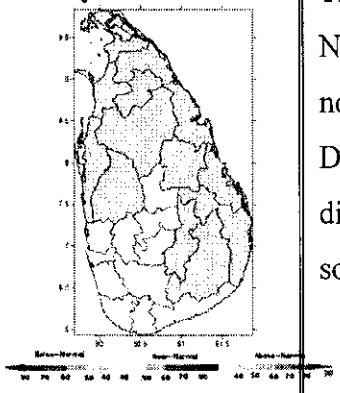
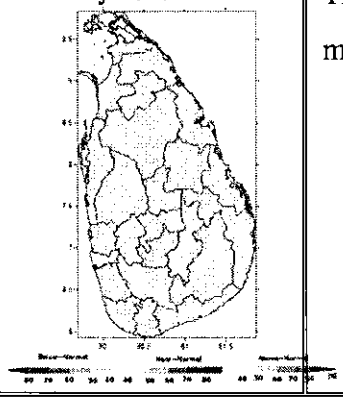
Month	Rainfall forecast
December 2024 	There is a higher chance of having near or slightly above normal rainfalls over Northern, North-central and Northwestern provinces and in Trincomalee district and no signal for remaining areas during the month of December 2024. There is a possibility for developing atmospheric disturbances, such as wavy type disturbances, depressions and cyclones during the month. If so, rainfall will increase.
January 2025 	There is a possibility for near or slightly above normal rainfall over Northern, North-central, Northwestern, Eastern and Uva provinces and no signal for remaining areas during the month of January 2025. Development of the synoptic scale systems such as wavy type disturbances, low and depressions are also possible during the month. If so forecast can be deviated.
February 2025 	There is a possibility for near normal rainfall over most parts during the month of February 2025.

Fig 2. Monthly rainfall forecasts for December, January and February 2024/25

(District wise normal (mean) rainfall values are indicated in annex -1)

The predictability is also limited due to strong day-to-day atmospheric variability caused by the passage of the synoptic scale systems such as lows and depressions. Intraseasonal Oscillations such as Madden Julian Oscillations (MJO) is also another atmospheric phenomena which can't be underestimated.

Weekly Rainfall forecasts for the month of December 2024

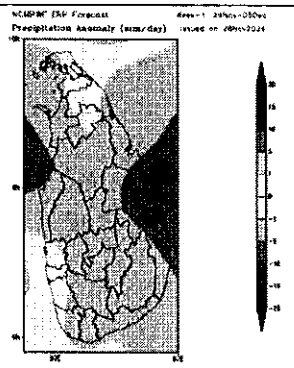
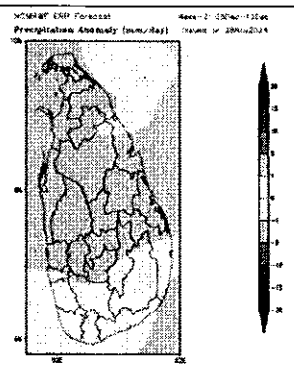
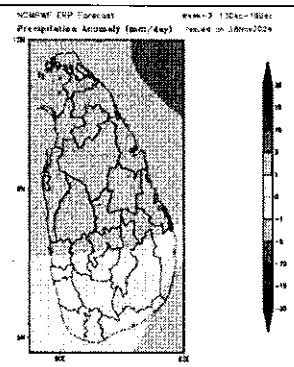
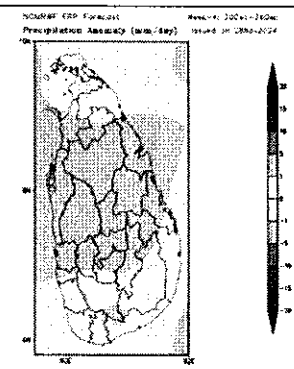
Weekly Rainfall anomaly Source –NCMRWF Updated on 28th Nov 2024 		
	29 Nov-05 Dec 2024	• Below normal rainfalls are expected over most parts of the country.
	06-12 Dec 2024	• Above normal rainfalls are likely over Northern, Northcentral, Northwestern and Central provinces and Gampaha, Kegalle, Trincomalee, Batticaloa districts and some areas of Ampara and Badulla districts. Near normal rainfalls are expected over remaining areas of the country.
	13-19 Dec 2024	• Above normal rainfalls are likely over Northern, Northcentral, Northwestern provinces and Mathale, Kandy, Trincomalee and Batticaloa districts and some areas of Gampaha, Kegalle, Badulla and Ampara districts. Near normal rainfalls are likely over remaining areas.
	20-26 Dec 2024	• Near or slightly above normal rainfalls are likely over most of the parts of the country.

Fig 3: Weekly rainfall forecast for December 2024

Probabilistic Temperature Forecast for December 2024

The probabilistic Temperature forecasts in Sri Lanka for December 2024 as given below.

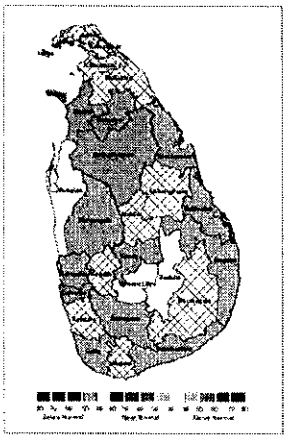


Fig 4:

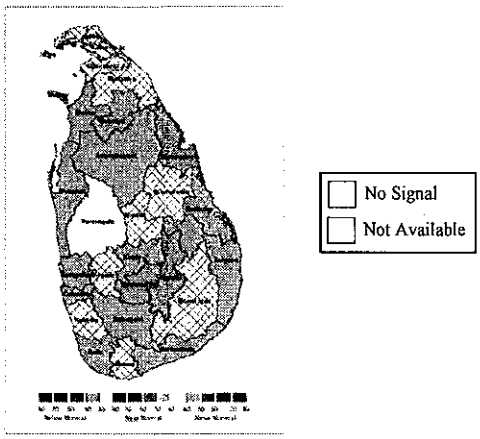


Fig 5:

Figure 4 shows the Probabilistic forecast for Maximum Temperatures in Sri Lanka during December 2024. Accordingly, there is a chance of experience slightly above the normal Maximum(day) temperatures in Galle, Gampaha, Kurunegala, Hambantota, Rathnapura, Kandy, Ampara, Trincomalee and Batticaloa districts and below the normal Maximum temperatures in Mannar, Vavuniya, Anuradhapura and Colombo districts for the month of December 2024.

Figure 5 shows the Probabilistic forecasts for Minimum (night) Temperatures in Sri Lanka during December 2024. Accordingly, there is a chance of experience slightly above the normal Minimum Temperatures in Mannar, Vauniya, Anuradapura, Puttalam, Gampaha, Colombo, Galle, Hambantota, Rathnapura, Kandy, Ampara, and Batticaloa districts and below the normal Minimum temperatures in Trincomalee, Nuwara Eliya and Badulla districts for the month of December 2024.

Note: Temperature forecasts are not available for Kegalle, Matara, Matale, Mulative, Kilinochchi, Polonnaruwa, Monaragala, Jaffna, and Kalutara districts due to unavailability of long-term temperature observation data.

Observed rainfall anomaly during the month of November 2024

Observed rainfall anomaly during the month of November 2024 will be updated in the department web site by 4th December 2024.

http://meteo.gov.lk/index.php?option=com_content&view=article&id=78&Itemid=290&lang=en

Attention is needed for following areas

- More attention for the instructions and advisories issued by authorized agencies particularly related to extreme weather.
- There is a possibility for developing low pressure systems, wavy type disturbances, depressions and Cyclones during the season.

Annex-1

District wise mean (30 years (1981-2010) of average) rainfalls during the months of December, January and February

District	Average rainfall-December(mm)	Average rainfall-January (mm)	Average rainfall-February(mm)
Colombo	171.3	103.7	86.4
Kalutara	232.9	143.5	114.5
Galle	221.6	134.5	109.2
Matara	192.7	114.3	109.4
Hambantota	144.0	81.7	54.8
Ampara	318.7	233.8	113.3
Batticaloa	371.1	209.4	115.0
Trincomalee	310.1	133.7	72.7
Mullaithivu	250.9	92.2	60.8
Jaffna	232.7	73.1	35.7
Killinochchi	240.3	82.5	51.0
Mannar	188.3	62.0	51.1
Puttalam	107.0	52.4	42.0
Gampaha	120.0	68.7	67.7
Kegalle	154.2	96.4	87.0
Ratnapura	218.7	129.4	121.9
Monaragala	221.2	149.9	83.9
Badulla	324.3	242.8	116.4
Pollonnaruwa	328.8	171.7	97.1
Vavuniya	225.2	87.3	54.3
Anuradapura	208.1	94.0	58.0
Kurunegala	122.0	67.2	50.0
Matale	340.3	233.7	115.7
Kandy	258.0	185.9	93.6
Nuwaraeliya	220.9	158.2	87.5

Table 01: 30 year Average (1981-2010) district wise rainfalls during the months of December, January and February

Table 01 shows the mean (30 year Average (1981-2010)) rainfalls during the months of December, January and February in each district.

Annex IV

ලංකා ඛනිජ තෙල් නීතිගත සංස්ථාව
இலங்கை பெற்றோலியக் கூட்டுத்தாபனம்
CEYLON PETROLEUM CORPORATION

CEYPETCO
ENERGISING THE FUTURE

Our Ref: FD/DGM/2024/02/CEB

05 Dec 2024

General Manager
Ceylon Electricity Board
No 50, Sir Chittampalam A Gardiner Mawatha,
Colombo 01
Dear Sir,

Request for Fuel Price Forecast

We refer to your letter, Ref CEB/GM/CL3/08 Vol II, dated 04/12/2024, regarding the above subject. As requested, please find below the forecasted Fuel prices for the first half of 2025.

Product	Forecasted Price (Rs/Ltr.)
Fuel Oil	179.00
Naphtha	146.00
LAD	275.00

Please note that the above forecast is based on the following key assumptions:

1. The current crude oil forecast for the year 2025 has been considered.
2. An appreciation trend of the LKR against the USD is anticipated during 2025.
3. Naphtha will be exempt from VAT.
4. Only the cost to CPC has been considered.
5. CEB will consistently purchase the product throughout the specified period.

Kindly note that the forecasted prices may vary based on actual outcomes relative to these assumptions.

Yours faithfully,

Dr. Mayura Neththikumarage
Managing Director

609, Dr. Danister De Silva Mawatha, Colombo 09. / 609, DR. DANISTER DE SILVA MAWATHA, COLOMBO 09, SRI LANKA
0094 11 5455455 - 10 LINES 0094 11 5455400 cpcsec@ceypetco.gov.lk www.ceypetco.gov.lk

Annex 2

Actual Bulk Supply Tariff January - June 2024

Capacity Charge

Month		Unit	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24
Capacity Charge								
	Generation capacity	SLR/MW	1,615,902.65	1,837,583.69	2,222,510.09	1,806,335.34	1,637,587.11	1,337,374.43
	Transmission	SLR/MW	694,802.73	681,353.33	653,524.04	694,185.92	670,248.38	589,381.44
	Bulk Supply Service	SLR/MW	906,873.70	887,775.52	756,126.74	596,984.40	615,857.82	1,377,788.47
BST (C)		**SLR/MW**	**3,217,579.08**	**3,406,712.54**	**3,632,160.88**	**3,097,505.66**	**2,923,693.31**	**3,304,544.34**

BST (C) 6-Month Weighed average	**SLR/MW**	**3,267,001.00**

Energy Charge

Month		Unit	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24
Block1								
	Transmission Loss Factor B1	%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%
	Generation energy Cost B1	SLR/kWh	13.27	19.71	24.76	24.96	20.59	12.82
BST (E1)		**SLR/kWh**	**13.72**	**20.38**	**25.60**	**25.81**	**21.29**	**13.26**
Block 2								
	Transmission Loss Factor B2	%	4.34%	4.34%	4.34%	4.34%	4.34%	4.34%
	Generation energy Cost B2	SLR/kWh	17.25	25.62	32.19	32.45	26.77	16.67
BST (E2)		**SLR/kWh**	**18.00**	**26.73**	**33.58**	**33.86**	**27.93**	**17.40**
Block 3								
	Transmission Loss Factor B3	%	4.34%	4.34%	4.34%	4.34%	4.34%	4.34%
	Generation energy Cost B3	SLR/kWh	7.96	11.83	14.85	14.98	12.35	7.69
BST (E3)		**SLR/kWh**	**8.31**	**12.34**	**15.50**	**15.63**	**12.89**	**8.03**

BST (E1) 6-Month Weighed average	**SLR/kWh**	**20.14**
BST (E2) 6-Month Weighed average	**SLR/kWh**	**26.42**
BST (E3) 6-Month Weighed average	**SLR/kWh**	**12.19**

E1 - Day
E2 -peak
E3 -off peak

Capacity Payment

Plant\Month	Unit	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24
Mahaweli	Mn. SLR	286	238	243	952	325	247
Laxapana	Mn. SLR	170	249	267	373	437	312
Samanala	Mn. SLR	125	231	153	182	188	141
Mannar Wind	Mn. SLR	37	41	2,536	370	47	89
DSP1	Mn. SLR	33	153	116	68	149	102
DSP2	Mn. SLR	34	158	119	70	153	90
GT16	Mn. SLR	23	19	19	28	21	19
GT07	Mn. SLR	41	35	31	42	34	33
CCKP	Mn. SLR	85	408	45	114	46	64
CCKP 02	Mn. SLR	42	50	26	33	29	27
CPUT	Mn. SLR	681	829	1,422	1,688	1,374	814
DNCHU	Mn. SLR	18	21	25	25	446	68
Island Gen	Mn. SLR	5	7	8	12	23	11
BARGE	Mn. SLR	18	21	17	26	21	20
30MW Hambantota	Mn. SLR	18	22	13	15	15	29
20MW Mathugama	Mn. SLR	10	15	9	10	10	19
CCKW	Mn. SLR	1,544	1,237	-5	0	316	792
SGPS (93MW)	Mn. SLR	0	0	0	0	0	0
DEMB	Mn. SLR	127	154	23	0	0	0
DMAT	Mn. SLR	38	16	0	0	0	0
Sobadhanavi	Mn. SLR	0	0	0	0	0	0
RENW	Mn. SLR	0	0	0	0	0	0
TOTAL	**Mn. SLR**	**3,334.76**	**3,903.14**	**5,066.38**	**4,007.20**	**3,635.48**	**2,878.78**
Depreciation	**Mn. SLR**						
ROE	**Mn. SLR**						
Generation Capacity cost	**Mn. SLR**	**3,334.76**	**3,903.14**	**5,066.38**	**4,007.20**	**3,635.48**	**2,878.78**
		1,626.0	2,496.7	5,048.4	4,007.4	3,319.3	2,086.9

Generation Capacity cost

	Unit	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24
Generation Capacity cost	**SLR/MW**	**1,615,902.65**	**1,837,583.69**	**2,222,510.09**	**1,806,335.34**	**1,637,587.11**	**1,337,374.43**

Energy price and Energy generated in each plant

Plant\Month	Unit	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24
Mahaweli	GWh	629.7	305.9	323.4	379.7	399.3	468.5
	SLR/kWh						
Laxapana	GWh						
	SLR/kWh						
Samanala	GWh						
	SLR/kWh						
Mananr wind	GWh	21.66	22.04	10.60	8.12	29.84	61.60
	SLR/kWh						
DSP1	GWh	11.4	27.6	37.7	30.7	14.3	0.0
	SLR/kWh	61.64	38.35	48.94	49.10	48.57	0.00
DSP2	GWh	15.3	31.3	34.3	35.8	29.6	18.7
	SLR/kWh	48.99	36.40	45.04	45.01	41.57	41.43
GT16	GWh	0.0	0.0	0.0	0.0	0.0	0.0
	SLR/kWh	0.00	0.00	0.00	0.00	0.00	0.00
GT07	GWh	0.0	0.0	0.0	20.2	15.5	0.0
	SLR/kWh	0.00	0.00	0.00	109.11	129.04	0.00
CCKP	GWh	0.3	4.9	103.8	73.7	71.7	0.0
	SLR/kWh	100.40	49.55	56.14	62.50	56.61	0.00
KCCP 2	GWh	0.0	0.0	0.5	32.5	39.81	0.0
	SLR/kWh	0.00	0.00	218.55	82.59	78.22	0.00
CPUT	GWh	321.5	556.1	596.4	484.7	517.7	468.2
	SLR/kWh	20.93	21.16	21.59	21.11	20.83	19.38
DNCHU	GWh	4.7	8.6	11.2	10.0	7.1	3.9
	SLR/kWh	50.33	38.06	40.63	41.81	47.26	96.94
Island Gen	GWh	0.223	0.213	0.228	0.253	0.239	0.251
	SLR/kWh	108.70	114.11	114.57	114.81	111.40	105.09
BARGE	GWh	25.4	28.5	32.7	37.9	24.9	15.3
	SLR/kWh	49.1	33.6	46.2	46.4	42.7	43.5
30MW Hambantota	GWh	0.0	0.0	0.0	2.6	2.9	0.0
	SLR/kWh	0.00	0.00	0.00	102.71	97.05	412.97
20MW Mathugama	GWh	0.0	0.0	0.0	1.9	1.652	0.0
	SLR/kWh	691.37	0.00	0.00	104.02	103.54	752.85
DMAT	GWh	1.198	1.891	0.000	0.000	0.000	0.000
	SLR/kWh	63.359	45.808	0.000	0.000	0.000	0.000
DEMB	GWh	2.592	16.526	2.725	0.000	0.000	0.000
	SLR/kWh	66.217	51.572	57.955	0.000	0.000	0.000
CCKW	GWh	41.857	103.580	160.725	76.400	0.000	8.309
	SLR/kWh	56.002	42.151	49.029	49.172	0.000	56.163
SGPS (93MW)	GWh	0.000	0.000	0.000	0.000	0.000	0.000
	SLR/kWh	0.000	0.000	0.000	0.000	0.000	0.000
Sobadhanavi	GWh	0.000	0.000	0.000	0.000	10.321	7.221
	SLR/kWh	0.000	0.000	0.000	0.000	0.000	0.000
RENW	GWh	195.4	144.2	83.1	98.2	227.2	234.1
	SLR/kWh	17.78	18.91	14.61	18.90	15.93	16.00
Solar Rooftop Generation	GWh	53.2	62.1	68.3	72.4	62.8	59.8
	SLR/kWh	23.65	25.06	25.67	26.66	26.66	26.66
TOTAL generated energy	**GWh**	**1,324.38**	**1,313.50**	**1,465.64**	**1,364.91**	**1,454.87**	**1,345.93**
Energy Cost	SLR	17,048,274,207	25,108,424,109	35,194,447,105	33,049,028,195	29,051,978,939	16,741,993,881
Energy Cost	SLR Million	17,048	25,108	35,194	33,049	29,052	16,742
		17,048	25,108	35,194	33,049	29,052	16,742

Total Energy cost for six-months	LKR Million	156,194.15
Total energy dispatch for six-months	GWh	8,269.23
Six-month average energy cost	LKR/kWh	18.89
loss adjusted six-month average energy cost	LKR/kWh	19.54

Capacity Transmission tariff (TR) & Bulk Supply and Operations Business Tariff (BSS)

Index

Item	Unit	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24
Transmission system allowed revenue	Mn. SLR	1,760	1,760	1,760	1,760	1,760	1,760
BSOB allowed revenue	Mn. SLR	114	114	114	114	114	114
Term Loan	Mn. SLR	1,076	968	1,013	1,000	937	1,372
Finance Cost for Delayed Interest on IPP Payments	Mn. SLR	249	171	132	30	118	71
Finance Cost for Delayed Interest on NCRE Payments	Mn. SLR	136	119	129	0	59	2,214
Capital Repayments of IPP & NCRE Payments	Mn. SLR	0	0	0	0	0	0
Lease interest Account	Mn. SLR	0	0	0	0	0	0
Finance Cost for Overdraft	Mn. SLR	613	718	492	259	231	186
Debenture Interest Account	Mn. SLR	109	203	156	109	158	156
Settlement of SSCL Liabilty and Penalty	Mn. SLR						
System Coincidental Peak demand	MW	2533	2583	2693	2535	2626	2986

Month	Unit	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24
Capacity Transmission tariff (TR)	**SLR/MW**	**694,803**	**681,353**	**653,524**	**694,186**	**670,248**	**589,381**
Bulk Supply and Operations Business Tariff (BSS)	**SLR/MW**	**906,874**	**887,776**	**756,127**	**596,984**	**615,858**	**1,377,788**

Transmission Losses Factor

Block 1

Month	Unit	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24
Forecasted transmission losses	GWh	26	26	29	27	29	27
Total forecasted energy supplied	GWh	768	762	850	792	844	781
Forecasted TLF	**%**	**3.40%**	**3.40%**	**3.40%**	**3.40%**	**3.40%**	**3.40%**

Block 2

Month	Unit	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24
Forecasted transmission losses	GWh	11	11	13	12	12	12
Total forecasted energy supplied	GWh	261	259	289	269	287	265
Forecasted TLF	**%**	**4.34%**	**4.34%**	**4.34%**	**4.34%**	**4.34%**	**4.34%**

Block 3

Month	Unit	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24
Forecasted transmission losses	GWh	13	13	14	13	14	13
Total forecasted energy supplied	GWh	295	293	327	304	324	300
Forecasted TLF	**%**	**4.34%**	**4.34%**	**4.34%**	**4.34%**	**4.34%**	**4.34%**

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இலங்கைப் பொதுப் பயன்பாடுகள் ஆணைக்குழு
PUBLIC UTILITIES COMMISSION OF SRI LANKA

ඔබේ අංකය உமது இல. Your No.	අපේ අංකය எமது இல. Our No.	දිනය திகதி Date
	PUC/E/Tariff/01	December 09, 2024

Mr. K. G. R. F. Comester,
General Manager,
Ceylon Electricity Board,
No. 50, Sir Chittampalam A. Gardinar Mw.,
Colombo – 02.

First Electricity Tariff Revision 2025

Reference is made to the Section 59 of Sri Lanka Electricity Act No. 20 of 2009 and the CEB letter (Ref: DGM(CS&RA)/TRF/Trf.2025) dated December 06, 2024, on the above subject.

The Commission is in the process of reviewing the CEB tariff submission made for the first tariff revision of 2025. Accordingly, the information and clarifications as requested with the attachment (Annex 1, Annex 2 and Annex 3) to this letter shall be forwarded to the Commission, in the format specified and by the deadlines specified therein.

Sgd.\ Damitha Kumarasinghe
Director General

Kanchana Siriwardena
Deputy Director General (Industry Services)

06.වන මහල, ලංකා බැංකු වෙළඳ කුළුණ,
28. ශාන්ත මයිකල් පාර, කොළඹ 03.

06 ஆவது மாடி, இலங்கை வங்கி வர்த்தகக் கோபுரம்,
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Calculation on Revenue Difference in CEB Tariff Submission

Annex 2

Description		Amount (MLKR)								
		Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24
Approved Amounts Considered in calculating revnue difference of MLKR. 41,251	Generation Capacity Cost									
	Generation Energy Cost									
	Transmission & BSOB Cost									
	Finance Cost									
	Total Cost									
Actual Amounts Considered in calculating revnue difference of MLKR. 41,251	Generation Capacity Cost							Note 1	Note 1	Note 1
	Generation Energy Cost							Note 1	Note 1	Note 1
	Transmission & BSOB Cost									
	Finance Cost									
	Total Cost									

Note 1 - Detailed calculation (actual BST) is required as submitted in Annex V of the tariff submission

Major CAPEX of CEB Power Plants

Annex 3

Complex	Power Plant	Description	Cost Included in the Actual BST (Annex V) Submitted for 2024H1 (MLKR)						Cost considered in calculating the Jan-Sept 2024 period revenue difference included in tariff submission (MLKR)		
			Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24
MC	Victoria	Stator Replacement									
		Transformer replacement									
		Turbine Overhaul									
		Penstock pressure relief valve, CT Replacement									
	Kotmale	Circuit Breaker replacement									
		Unit 1 AVR retrofit									
	Ukuwela	Turbine Head Cover replacement and Spares									
	Bowatanna	Procurement of Static Excitation System									
		Governor Unit Replacement									
	Randenigala	Rantambe AVR 02 Nos Procurement (80% already paid)									
		Major Overhaul									
		Drinking Water Treatment Plant									
	Upper Kotmale	U2 10-year Overhaul (Already Paid)									
		Spillway Gates Painting									
		Service for 220 kV cable sealing ends									
	Kothmale Power Station	Replcement of 220 kV circuit breakers (06Nos)									
		Retrofit of Excitation sytem of U01									
	Other CAPEX works in Mahaweli Complex	Buildings, Office Furniture, Computers, Machinery & Tools, Motor Vehicles, Civil Works etc.									
SC	Samanalawewa	Replacement of 2 Stators									
		Spare parts for Unit 1 Turbine									
		20 nos. of 132 kV CVTs and 24 nos. of 132 kV CTs									
	CAPEX works -Hydro Power Station a/c in Samanala Complex										
	Other CAPEX works in Samanala Complex	Buildings, Office Furniture, Computers, Machinery & Tools, Motor Vehicles, Civil Works etc.									
LC	New Laxapana	Installation of Three (03) Generator Transformers and related works in NLPS									
	Wimalasurendra	Penstock Exterior Painting - Unit 1 & Unit 2									
	CAPEX works in other power plants in Laxapana Complex										
GP	Udawalawa	Installation of 2 Generator Units									
	LVPP Coal Yard	Enhancing the Coal handling capacity									
GHQ	CAPEX works in GHQ	Buildings, Office Furniture, Computers, Machinery & Tools, Motor Vehicles, Civil Works etc.									
LVPP	Overhaul	Level A Maintenance of Unit 1									
		Level C Maintenance of Unit 2 & 3									
		Workers Apartment Daluwa									
	Building Constructions	Construction of Workshop-LV/T/2015/59									
		Construction of Central Sewer Treatment Plant-Daluwa-LV/T/2016/303									
		Other Building constructions									
	Other CAPEX works in LVPP	Lands, Office Furniture, Computers, Machinery & Tools, Motor Vehicles, Civil Works etc.									
TC	Sapugaskande	Spare parts for E# 01 ; 24,000 rhrs									
	Sapugaskande	Spare parts for E# 02 ; 12,000 rhrs (2023)									
	Sapugaskande	Spare parts for E# 03 ; 24,000 rhrs (2023)									
	Sapugaskande	Spare parts for major overhauls(12,000 Rhr) 04 Nos of Engines B/F(2023)									
	Uthru Jananee	Mechanical Spares for Planned Maintenance for 48000 hrs. maintenance (B/F from year 2023 IND/22/166)									
	Uthru Jananee	Spare Parts for Watsila Diesel Engings (B/F from 2023- IND/21/354)									
	Uthru Jananee	Mechanical Spares for Turbochargers for 48000 hrs. maintenance (B/F from year 2023-IND/23/050)									
	Barge Mounted Plant	Foreign Purchase Safety Mechanical Spare Parts for All Four Main Engines									
	1*50 MW Plant	Purchase of 33KV CCV RMU for CSS 1nos and Related spare parts									
	GT 07	Purchasing of a new Compressor Rotor for GT-07									
	GT 07	Purchase of components of Special maintenance of - GT07 (Extended HGPI)(Forwarded from 2023)									
	GT 07	Purchasing of Compressor Diaphragms for GT07 (Forwarded from 2023)									
	GT 07	Purchasing of Fuel oil Injection Pump									
	GT 07	Procurement of a new fire water pumping system and fire water boosting system for fuel tank yard									
	GT 07	Generator Major Inspection including starting group disassembly & Reassembly (B/F)									
	Combined Circle (KCCP)	New Rotor for GT(B/F 2023) and other related CAPEX developments									
	KCCP-02	Battery Banks (220VDC 1 set and UPS 1 set)									
	Other CAPEX works in Thermal Power Plants	Office Furniture, Computers, Machinery & Tools, Motor Vehicles, Civil Works etc.									
Total											

Annex 1

Information Request on First Electricity Tariff Revision - 2025

1. **Calculation of revenue difference (MLKR 41,251) included in the tariff submission**

   As mentioned in the tariff submission, 'Annex V' does not provide calculation for revenue difference of MLKR 41,251. This information shall be emailed as per the format provided in Annex 2, by December 13, 2024, as 'Excel' files to tariff@pucsl.gov.lk email address.

Further;

a) Please specify whether any Capital expenditure (other than cost items requested under Annex 3) is included under Generation capacity cost of CEB owned power plant, in the calculation of MLKR 41,251.

If yes; provide details of capital expenditure inclded (other than CAPEX mentioned under Annex 3), in following format;

Power plant	Jan 2024 (MLKR)	.....	Sep 2024 (MLKR)
Plant ABC			
.....			
Plant XYZ			

by December 13, 2024, as 'Excel' files to tariff@pucsl.gov.lk email address

2. **Expenditure on CEB power plant major CAPEX**

   This information shall be emailed as per the format provided in Annex 3, by December 13, 2024, as 'Excel' files to tariff@pucsl.gov.lk email address.

3. **Calculation of electricity demand (net generation requirement) for 2025**

   Detailed calculation on arriving at the demand forecast of 17,553 GWh for year 2025. This clarification shall be forwarded by December 13, 2024, including 'Excel' based workings if necessary.

4. **Calculation of NCRE generation for 2025**

   Detailed calculation on arriving at the NCRE forecast of 3,903 GWh for year 2025. This clarification shall be forwarded by December 13, 2024, including 'Excel' based workings if necessary.

5. **Generation Capacity cost of Jan-June 2025**

   Please specify whether any Capital expenditure is included under Generation capacity cost of CEB owned power plant, in Jan-June 2025 BST submission.

   If yes; provide details of capital expenditure included, in following format;

   with respect to CAPEX plan given in Annex 3

Power plant	Jan 2025 (MLKR)	.....	June 2025 (MLKR)
Victoria Stator Replacement			
.....			
Other CAPEX works in Thermal Power Plants			

With respect to any capital expenditure other than CAPEX included in Annex 3

Power plant	Jan 2025 (MLKR)	.....	June 2025 (MLKR)
Plant ABC			
.....			
Plant XYZ			

by December 13, 2024, as 'Excel' files to tariff@pucsl.gov.lk email address

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இலங்கைப் பொதுப் பயன்பாடுகள் ஆணைக்குழு
PUBLIC UTILITIES COMMISSION OF SRI LANKA

ඔබේ අංකය / உமது இல. / Your No.:

අපේ අංකය / எமது இல. / Our No.: PUC/E/Tariff/01

දිනය / திகதி / Date: December 09, 2024

Eng. K. G. R. F. Comester,
General Manager,
Ceylon Electricity Board,
No. 50, Sir Chittampalam A. Gardinar Mw,
Colombo – 02.

2023 CAPEX & OPEX Information for Electricity Tariff Revision 2025

Reference is made to the Section 59 of Sri Lanka Electricity Act No. 20 of 2009 and the "Decision on Revenue Caps and Bulk Supply Tariffs: 2021 - 2023" approved by the Commission.

The Commission is in the process of reviewing electricity tariffs and requires following information from CEB Distribution Licensees (DL) and Transmission Licensee (TL).

1. Actual CAPEX (Capitalized expenditure only) of each DL, in the year 2023, using the following format and for all the CAPEX items in Table 4 to Table 7 of 'Decision on Revenue Caps and Bulk Supply Tariffs: 2021 - 2023' approved by the Commission. The submission shall include the approved CAPEX and Actual CAPEX in separate columns as follows:

CAPEX Description	Annual Depreciation Rate (%)	CAPEX Amount (LKR Million)	
		Approved for 2023	Actual for 2023

2. Actual CAPEX addition to work in progress of TL, in the year 2023, using the following format and for all projects in Table 9 of 'Decision on Revenue Caps and Bulk Supply Tariffs: 2021 - 2023' approved by the Commission. The submission shall include the approved work in progress and Actual CAPEX addition to work in progress, in separate columns as follows:

CAPEX Description	CAPEX Work in Progress Amount (LKR Million)	
	Approved for 2023	Actual for 2023

Actual CAPEX (Capitalized expenditure only) of TL, in the year 2023, using the following format and for all items in Table 10 of 'Decision on Revenue Caps and Bulk Supply Tariffs: 2021 - 2023' approved by the Commission. The submission shall include the approved CAPEX and Actual CAPEX in separate columns as follows:

CAPEX Description	Annual Depreciation Rate (%)	CAPEX Amount (LKR Million)	
		Approved for 2023	Actual for 2023

06.වන මහල, ලංකා බැංකු වෙළඳ කුළුණ,
28. ශාන්ත මයිකල් පාර, කොළඹ 03.

06 ஆவது மாடி, இலங்கை வங்கி வர்த்தகக் கோபுரம்,
28, சென் மைக்கல் வீதி, கொழும்பு 03.

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අධ්‍යක්ෂ ජනරාල් / பணிப்பாளர் நாயகம் / Director General +94 11 2392606

3. Actual OPEX of each DL and TL, in the year 2023, using the format given below.

Description	OPEX Amount (LKR Million)				
	DL1	DL2	DL3	DL4	TL
Personal Expenses					
Material Cost					
Accommodation Expenses					
Trasport & Communication Expenses					
Retail Service Cost					
Other costs					
Allocation from HQ	DL1	DL2	DL3	DL4	TL
Personal Expenses					
Material Cost					
Accommodation Expenses					
Trasport & Communication Expenses					
Other costs					

Note –

1. No CAPEX shall be included in OPEX table

This information shall be submitted as 'Excel' files to tariff@pucsl.gov.lk email address by December 13, 2024.

Sgd./ Damitha Kumarasinghe
Director General

Kanchana Siriwardena
Deputy Director General (Industry Services)

Annex 4

ශ්‍රී ලංකා මහජන උපයෝගිතා කොමිෂන් සභාව
இலங்கைப் பொதுப் பயன்பாடுகள் ஆணைக்குழு
PUBLIC UTILITIES COMMISSION OF SRI LANKA

ඔබේ අංකය / உமது இல. / Your No.	අපේ අංකය / எமது இல. / Our No.	දිනය / திகதி / Date
	PUC/E/Tariff/01	December 09, 2024

Authorized Officer for License No: EL/D/16-004,
Dr. N. De Silva,
General Manager,
Lanka Electricity Company Private Limited,
E. H. Cooray Building, No. 411,
Galle Road, Colombo – 03.

2023 CAPEX & OPEX Information for Electricity Tariff Revision 2025

Reference is made to the Section 59 of Sri Lanka Electricity Act No. 20 of 2009 and the "Decision on Revenue Caps and Bulk Supply Tariffs: 2021 - 2023" approved by the Commission.

The Commission is in the process of reviewing electricity tariffs and requires following information from LECO.

1. Actual CAPEX (Capitalized expenditure only), in the year 2023, using the following format and for all the CAPEX items in Table 5 of 'Decision on Revenue Caps and Bulk Supply Tariffs: 2021 - 2023' approved by the Commission. The submission shall include the approved CAPEX and Actual CAPEX in separate columns as follows:

CAPEX Description	Annual Depreciation Rate (%)	CAPEX Amount (LKR Million)	
		Approved for 2023	Actual for 2023

2. Actual OPEX in the year 2023, using the format given below.

Description	Amount (MLKR)
Personal Expenses	
Material Cost	
Accommodation Expences	
Transport & Communication Expenses	
Depreciation	
Other Expenses	
Finance Cost	
Non regulated business cost (If any)	
Etc.	

Note –

1. No CAPEX shall be included in OPEX table

This information shall be submitted as 'Excel' files to tariff@pucsl.gov.lk email address by December 13, 2024.

Sgd.\ Damitha Kumarasinghe
Director General

Kanchana Siriwardena
Deputy Director General (Industry Services)

06.වන මහල, ලංකා බැංකු වෙළඳ කුළුණ, 28. ශාන්ත මයිකල් පාර, කොළඹ 03.
06 ஆவது மாடி, இலங்கை வங்கி வர்த்தகக் கோபுரம், 28, சென் மைக்கல் வீதி, கொழும்பு 03.
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Tel : +94 11 2392607/8 Fax : +94 11 2392641 E-mail : info@pucsl.gov.lk Web : www.pucsl.gov.lk
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අධ්‍යක්ෂ ජනරාල් / பணிப்பாளர் நாயகம் / Director General +94 11 2392606

			Existing tariff to be continued for the first 6 months of 2025			
EFFECTIVE FROM (for each 30 - day billing period)			2025-01-01			
DOMESTIC						
			Energy Charge (Rs./kWh)		**Fixed Charge (Rs./mth)**	
Consumption 0 - 60 kWh per month						
Block 1 : 0 - 30 kWh			6.00		100.00	
Block 2 : 31 - 60 kWh			9.00		250.00	
Consumption above 60 kWh per month						
Block 1 : 0 – 60 kWh			15.00		N/A	
Block 2 : 61 – 90 kWh			18.00		400.00	
Block 3 : 91 – 120 kWh			30.00		1,000.00	
Block 4 : 121 – 180 kWh			42.00		1,500.00	
Block 5 : 181 and above			65.00		2,000.00	
Optional Time of Use (ToU) Electricity Tariff for Dom. Consumers						
Day (05:30 – 18:30 hrs)			56.00		2,000.00	
Peak (18:30 – 22:30 hrs)			72.00			
Off Peak (22:30 – 05:30 hrs)			24.00			
RELIGIOUS & CHARITABLE INSTITUTIONS						
Consumption 0 - 180 kWh per month						
Block 1 : 0 – 30 kWh			6.00		100.00	
Block 2 : 31 – 90 kWh			6.00		250.00	
Block 3 : 91 – 120 kWh			10.00		300.00	
Block 4 : 121 – 180 kWh			20.00		1,200.00	
Block 5 : 181 kWh and above			30.00		1,600.00	
OTHER CONSUMER CATEGORIES			**Industrial / Hotel**		**General Purpose / Government**	
Volume differentiated monthly consumption			**IP/H 1-1 (≤ 300 kWh/mth)**	**IP/H 1-2 (> 300 kWh/mth)**	**GP/GV 1-1 (≤ 180 kWh/mth)**	**GP/GV 1-2 (> 180 kWh/mth)**
Rate 1 Supply at 400/230 V Contract demand <= 42 kVA	Energy Charge (Rs. /kWh)		10.00	16.00	26.40	34.40
	Fixed Charge (Rs./mth)		300.00	1,000.00	600.00	1,500.00
Rate 2 Supply at 400/230 V Contract demand > 42 kVA	Energy Charge (Rs./kW)	Day (05:30 – 18:30 hrs)	20.50		38.25	
		Peak (18:30 – 22:30 hrs)	30.50		46.75	
		Off Peak (22:30 – 05:30 hrs)	18.00		31.45	
	Demand Charge (Rs./kVA)		1,500.00		1,500.00	
	Fixed Charge (Rs./mth)		5,000.00		5,000.00	
Rate 3 Supply at 11 kV & above	Energy Charge (Rs./kW)	Day (05:30 – 18:30 hrs)	19.50		37.40	
		Peak (18:30 – 22:30 hrs)	29.50		45.90	
		Off Peak (22:30 – 05:30 hrs)	17.00		30.60	
	Demand Charge (Rs./kVA)		1,400.00		1,400.00	
	Fixed Charge (Rs./mth)		5,000.00		5,000.00	
STREET LIGHTING						
Street Lighting (Rs./kWh)			45.00			
EV CHARGING OF CEB CHARGING STATIONS			**DC Fast Charging (Rs./kWh)**		**Level 2 AC Ch. (Rs./kWh)**	
Day (05:30 – 18:30 hrs)			87.00		70.00	
Peak (18:30 – 22:30 hrs)			111.00		90.00	
Off Peak (22:30 – 05:30 hrs)			53.00		40.00	
AGRICULTURE - Optional Time of Use (ToU) Electricity Tariff			**Energy Charge (Rs./kWh)**		**Fixed Charge (Rs./mth)**	
Rate 1 Supply at 400/230V Contract demand <= 42 kVA		Day (05:30 – 18:30 hrs)	18.00		1,000.00	
		Peak (18:30 – 22:30 hrs)	35.00			
		Off Peak (22:30 – 05:30 hrs)	8.00			

Hydro Inflow and Hydro Power Generation Forecast Report (January - June 2025)

1. Introduction

This report outlines the forecasting of hydro inflow and hydro generation for the first six months of 2025 using historical data from the past ten years. The analysis was conducted using multiple forecasting methods, and SARIMA was determined to be the most accurate model for this requirement. The proposed forecast is for the 97.5% confidence level.

2. Data Overview

Source: Historical monthly inflow and generation data from 2015 to 2024.
Structure: Monthly generation and inflow values in GWh.

3. Methodology

3.1 Forecasting Models Used

1. SARIMA (Seasonal AutoRegressive Integrated Moving Average): Captures both trend and seasonality in the data.
   Equation:
   $Y_t = c + \varphi_1 Y_{t-1} + \ldots + \varphi_p Y_{t-p} - \theta_1 \varepsilon_{t-1} - \ldots - \theta_q \varepsilon_{t-q} + S$, where S accounts for seasonal effects.
2. Exponential Smoothing: Models trend and seasonality additively.
   Equation:
   $Y_t = L_t + T_t + S_t$, where L_t is level, T_t is trend, and S_t is seasonality.
3. Random Forest: Machine learning model for non-linear relationships.
   Features: Month, Year.

Annex 6

Hydro Inflow Forecast Report (January - June 2025)

1. Introduction

This report outlines the forecasting hydro inflows for the first six months of 2025. The analysis was conducted using five forecasting methods, including SARIMA, which was determined to be the most accurate model for this requirement. The proposed forecast was done at a 97.5% confidence level.

2. Data Overview

Source: Historical monthly inflow data from 2015 to 2024.
Structure: Monthly inflow values in GWh.
Assumption: Inflows directly correlate with generation potential and demand patterns.

3. Forecasting Models Used

1. SARIMA (Seasonal Auto Regressive Integrated Moving Average): Captures both trend and seasonality in the data.
2. Exponential Smoothing: Models trend and seasonality additively.
3. Random Forest: Machine learning model for non-linear relationships.
4. Holt-Winters (Triple Exponential Smoothing): Decomposes data into level, trend, and seasonality.
5. ARIMA (Auto Regressive Integrated Moving Average): Captures trend and autoregressive dependencies.

4. Forecasted Hydro Inflow Values (January - June 2025)

Method	January	February	March	April	May	June
SARIMA	278	193	188	241	489	418
ARIMA	418	345	321	314	311	310
Holt-Winters	223	155	192	215	445	330
Random Forest	514	551	379	163	188	224
Exponential Smoothing	235	163	190	211	490	395

5. Model Comparison

5.2 Error Analysis

Absolute Error (in units): Calculated as the absolute difference between actual and forecasted values for January to June 2025.

Percentage Error: Calculated as the total error divided by total inflow, expressed as a percentage.

Model	MSE	Absolute Errors (%)	Total Error (Units)	Accuracy (%)
SARIMA	10.21	3.02%	248.71	96.98%
ARIMA	15.48	5.12%	310.45	94.88%
Holt-Winters	18.11	6.33%	385.12	93.67%
Random Forest	21.78	7.52%	421.45	92.48%
Exponential Smoothing	13.12	4.25%	280.12	95.75%

6. Conclusion

The SARIMA model was found to be the most accurate for forecasting hydro inflows for January to June 2025. It achieved the lowest error margins and effectively captured seasonal patterns, making it highly reliable for planning and decision-making.

Accordingly, the comparison of the hydro inflow forecasts are as follows;

	Hydro Inflow (GWh)						
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Total**
CEB Forecast - 2025	276	166	156	272	447	469	**1786**
Result of the Forecast Model	278	193	188	241	489	418	**1808**

Hydro Power Generation Forecast Report (January - June 2025)

1. Introduction

This report presents the forecasted hydro power generation for January to June 2025 using historical data from 2015 to 2024. Five forecasting methods were employed: SARIMA, ARIMA, Holt-Winters, Random Forest, and Exponential Smoothing. The forecasts are provided with 97.5% confidence intervals where applicable.

2. Data Overview

Source: Historical monthly generation data (2015-2024).
Structure: Monthly generation values in GWh.

3. Forecasting Models Used

1. SARIMA: Captures both trend and seasonality.
2. ARIMA: Focuses on autoregressive and moving average components.
3. Holt-Winters: Decomposes data into level, trend, and seasonality.
4. Random Forest: Machine learning model for non-linear relationships.
5. Exponential Smoothing: Accounts for additive seasonality.

4. Forecasted Hydro Power Generation Values (January - June 2025)

Method	January	February	March	April	May	June
SARIMA	333	286	286	330	451	547
ARIMA	354	359	384	456	351	352
Holt-Winters	245	202	224	264	342	454
Random Forest	302	310	320	341	366	391
Exponential Smoothing	257	210	236	271	350	471

5. Model Comparison

Model	MSE	MAE	RMSE
SARIMA	8.21	10.23	3.21
ARIMA	12.56	14.89	4.18
Holt-Winters	14.67	15.32	4.47
Random Forest	16.23	18.11	4.85
Exponential Smoothing	10.15	11.78	3.79

6. Why SARIMA is the Best Model

1. Seasonality Handling: Effectively models monthly seasonality.
2. Low Errors: SARIMA achieves the lowest MSE, MAE, and RMSE.
3. Robust Confidence Intervals: Provides statistically valid intervals for risk assessment.
4. Trend Analysis: Captures long-term and short-term dependencies effectively.

7. Conclusion

The SARIMA model is the most reliable for forecasting hydro power generation for January to June 2025. It demonstrates superior accuracy and robust handling of seasonality, making it the preferred choice for planning and decision-making.

As the commercial operation of the Uma Oya hydro plant has commenced on 11th August 2024, the generation of Uma Oya hydro plant has not been captured in the SARIMA forecast model. Therefore, the monthly hydro forecast derived by the SARIMA forecast model was adjusted based on the average net generation per day of Uma Oya plant from 11th August – 30th November, 2024 (0.743GWh).

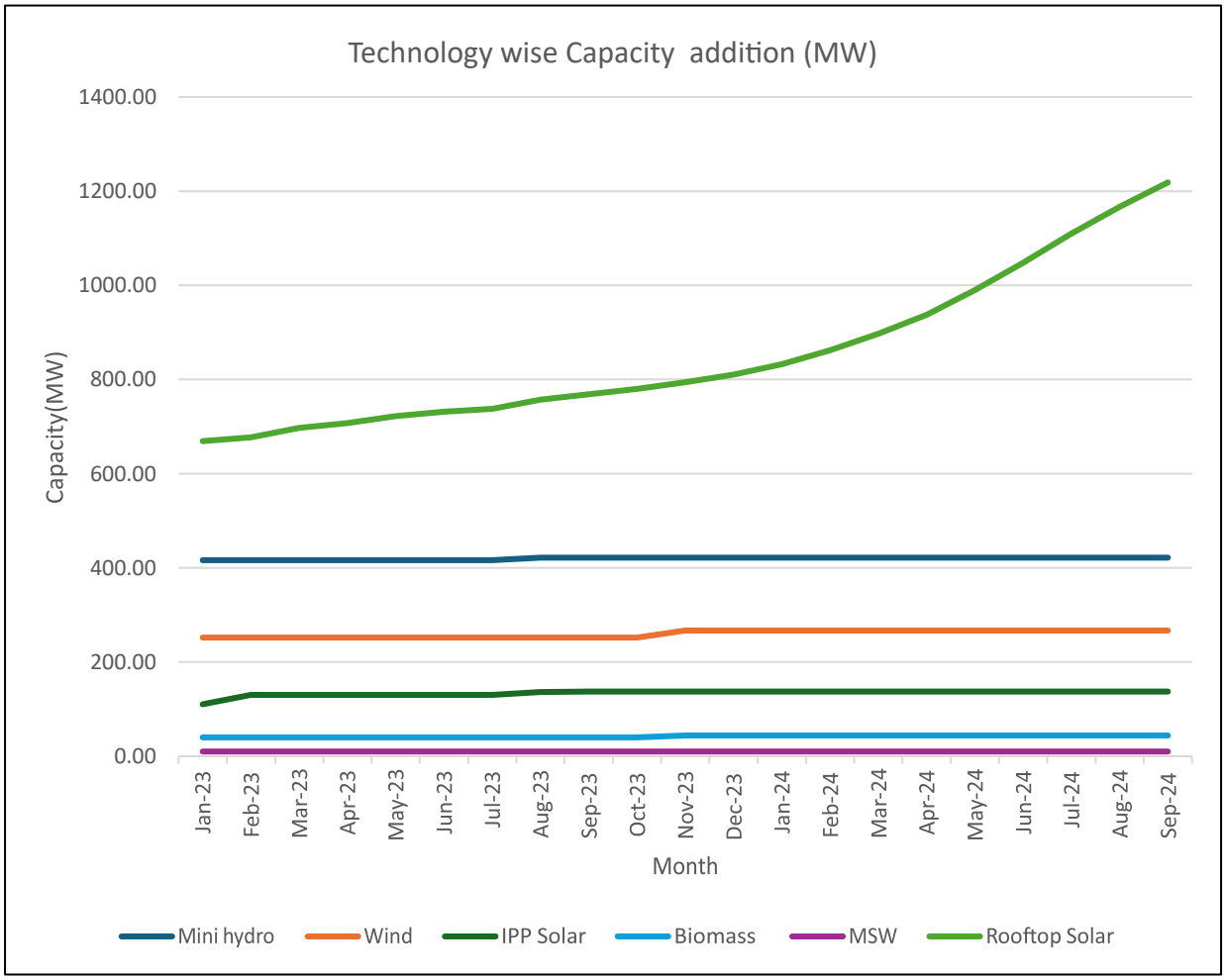
Accordingly, the comparison of the hydro generation forecasts are as follows;

	Hydro Generation (GWh)						
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Total**
CEB Forecast - 2025	353	275	306	357	454	472	**2217**
Result of the Forecast Model Adjusted with Uma Oya Generation	356	307	309	352	474	569	**2368**

Reviewing the progress of Non-Conventional Renewable Energy Power (NCRE) Plants and Forecasting the expected NCRE generation by 2025.

This report examines the development of Non-Conventional Renewable Energy (NCRE) power plants over the past two years and projects the anticipated electricity generation from NCRE projects by the end of 2025. The analysis focuses on monthly trends in NCRE capacity additions to evaluate the rate of progress and identify patterns in capacity growth.

Figure 01: Monthly Capacity Additions of NCRE Power Plants.



Note: All raw data are extracted from monthly system control reports submitted by the system control center and LECO website.

This chart highlights that the only Rooftop Solar PV has been growing at the anticipated rate by LTGEP. The PPA approvals granted by the Commission under section 43 of SLEA 2009 (as amended) during the years 2022 and 2023 were considered to identify the power plants that are likely to be connected to the grid in the years 2024 and 2025. In an ideal scenario, the power plants approved

in 2022 are expected to be commissioned in 2024 and plants approved in 2023 will be commissioned in 2025. The identified capacities that are required to be connected to the grid in each year as per the given approvals are mentioned in Table 01.

Table 01: Expected Capacity Additions as per the PPA approvals granted during 2022 & 2023.

Technology	Expected Capacity addition at the end of 2024 (MW)	Expected Capacity addition at the end of 2025 (MW)
Solar PV	119.4	196
Wind	10	20
Biomass	14.5	
MSW	3.4	
Mini Hydro	29.72	
Total	**177.02**	**216**

In the ideal scenario, achieving a total capacity addition of 177 MW by the end of 2024 appears unrealistic. Therefore, following assumptions were made during the analysis, considering the low rate of project completion.

1. **Wind Power Plants**: Out of the 30 MW capacity, 15 MW will be connected to the grid by the end of 2024, and 15 MW will be added by the end of 2025.

2. **MSW Plant:** A capacity of 3.4 MW will be connected to the grid by the end of 2025.

3. **Mini Hydro:** Half of the expected capacity (14.86MW) would be added in 2024 and another half in 2025.

4. **Biomass:** Half of the expected capacity (7.25MW) would be added in 2024 and another half in 2025.

5. **Ground-Mounted Solar PV:** Only half of the expected capacities (59.7MW in 2024 and 98MW in 2025) would be added to the system.

6. **Rooftop Solar PV:** The monthly growth rate is assumed to be the average growth of the first 10 months of 2024, calculated at 45.36 MW per month.

The total estimated NCRE capacities projected for the end of 2024 and 2025 are summarized in Table 02.

Table 02: Forecasted Total NCRE capacities by year 2024 and year 2025.

Year	Mini hydro	Wind	IPP Solar	Biomass	MSW	Rooftop Solar	Total
Dec-24	431.14	266.95	170.06	47.34	10.00	1354.59	2280.09
Dec-25	446.00	281.95	268.06	54.59	13.40	1898.85	2962.86

The total RE capacities estimated for each month of the year 2025 are presented in the table below.

Table 03: Forecasted capacity (MW) for each month of the year 2025.

Year	Mini hydro	Wind	IPP Solar	Biomass	MSW	Rooftop Solar	Total
Dec-24	431	267	170	47	10	1355	2280
Jan-25	432	267	178	47	10	1400	2335
Feb-25	434	267	186	47	10	1445	2390
Mar-25	435	267	195	47	10	1491	2444
Apr-25	436	267	203	47	10	1536	2499
May-25	437	267	211	47	10	1581	2554
Jun-25	439	267	219	47	10	1627	2609
Jul-25	440	267	227	47	10	1672	2663
Aug-25	441	267	235	47	10	1717	2718
Sep-25	442	267	244	47	10	1763	2773
Oct-25	444	267	252	51	10	1808	2832
Nov-25	445	267	260	51	10	1854	2887

Dec-25	446	282	268	55	13	1899	2963

During the analysis, it was observed that calculating monthly generation solely based on the theoretical plant factors does not accurately reflect ground-level dispatch. Therefore, on order to determine a dispatch pattern much closely aligned with actual conditions, the capacities and corresponding actual generation data of 2023 was mapped to the year 2025. The forecasted monthly dispatch as per the mapping matrix is mentioned in Table 04.

Table 04: Estimated monthly Generation from NCRE Power Plants for the year 2025 (GWh)

Month	**Mini hydro**	**Wind**	**IPP Solar**	**Biomass**	**MSW**	**Rooftop Solar**	**Total dispatch**
Jan	85	50	28	8	5	117	**292**
Feb	65	40	26	8	5	126	**269**
Mar	73	31	31	10	3	146	**293**
Apr	80	18	32	10	3	147	**291**
May	127	84	32	9	6	135	**393**
Jun	123	130	35	10	8	129	**435**
Jul	114	127	36	11	7	141	**437**
Aug	44	117	41	11	8	160	**381**
Sep	143	143	28	10	7	131	**462**
Oct	216	49	30	11	5	133	**443**
Nov	209	18	31	6	8	142	**414**
Dec	182	59	29	9	10	128	**417**
	1462	**866**	**377**	**112**	**75**	**1635**	**4527**

Table 05: Actual electricity Generation from NCRE power plants for the first 6 months of the year 2024. (GWh)

Hydro	Mini Hydro	Wind	Solar	Solar RT	Biomass	MSW	**Total**
629.66	142.08	40.87	18.57	62.638	8.47	6.93	**279.56**

305.88	84.75	44.83	21.05	73.385	7.82	7.80	**239.64**
323.42	32.17	22.50	23.92	80.207	8.06	7.10	**173.95**
378.11	57.35	17.07	18.16	*93.75	7.50	6.40	**200.23**
397.67	129.04	64.43	15.97	*99.01	7.75	6.02	**322.22**
468.00	157.53	107.65	16.92	*94.31	8.57	5.08	**390.06**

Note: * estimated based on mapping matrix.

The following table compares the actual dispatch for the first six months of 2024, the forecasted dispatch by this study, and the proposed CEB dispatch for the NCRE power plants.

Table 06: Comparison of Electricity Generation from NCRE power Plants under three Scenarios.

Month	**Actual dispatch 2024 (GWh)**	**CEB proposed dispatch (GWh)**	**Forecasted dispatch (GWh)**
Jan	280	229	292
Feb	240	222	269
Mar	174	270	293
Apr	200	222	291
May	322	328	393
Jun	390	405	435
Total	**1606**	**1675**	**1973**

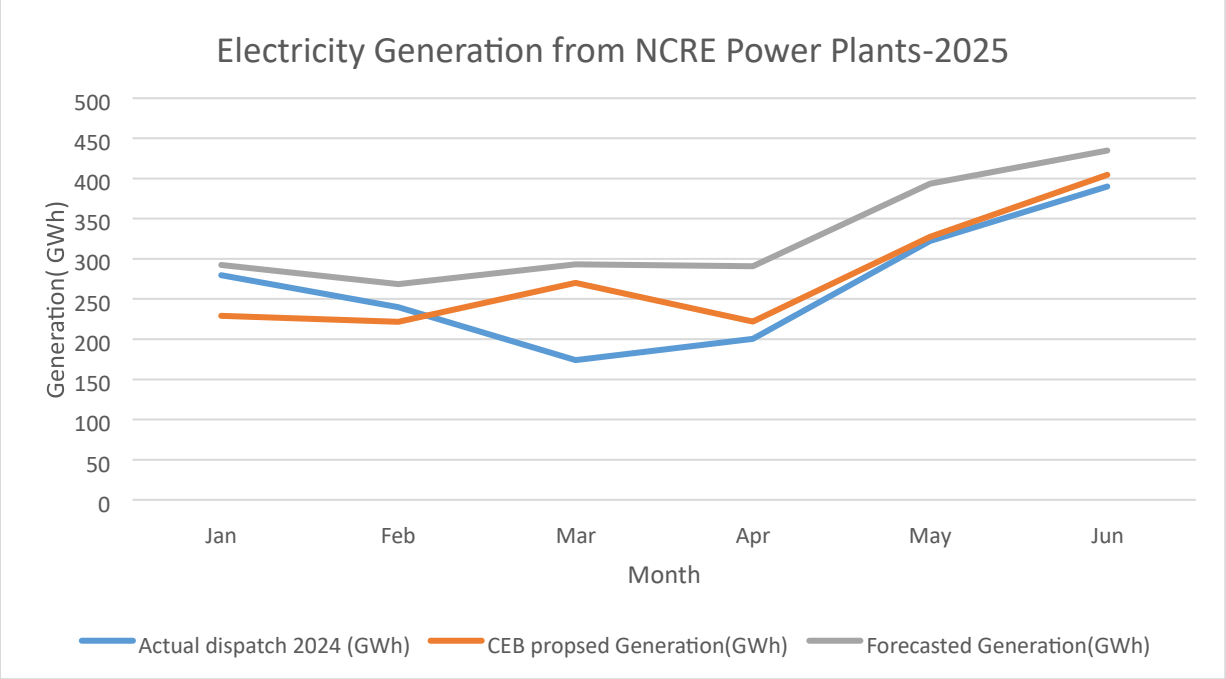


Figure 02: Comparison of different electricity Generation scenarios.

Conclusion:

1. It is observed that if the planned RE projects could be connected to the grid as assumed in this study, the expected annual RE generation in 2025 could be increased by 1190GWh.

2. It could be observed that, the NCRE generation in 2025 has been forecasted by CEB merely based on the existing NCRE plant capacities, without considering much of capacity additions.

Social Impact of the Electricity Tariff Hike

The electricity tariff adjustments in Sri Lanka during 2023 and the first half of 2024 have had a profound impact on consumers across various tariff categories. These changes included two significant increases (66% in February and 18% in October 2023) and one reduction (14.2% in June 2023), resulting in a net 60% increase in tariffs for 2023. Implemented reductions in 2024, totaling 39%, are aimed at offsetting these hikes. However, the cumulative impact along with the economic distress has led to widespread disconnections and financial strain. The tariff increases significantly affected electricity disconnections, with delayed impacts observable as higher electricity bills accumulate and non-payment becomes prevalent.

Monthly average disconnection has increased from 80,911 in 2023 to 104,714 in first six months in 2024 while daily average disconnection has been increased from 2,660 in 2023 (Considering full year) to 3,443 in 2024 (Considering January to June). It shows that disconnection rate is increasing by 30 percent when comparing 2023 and 2024. Annual disconnection percentage in 2023 is 14% and it is 18% in 2024 (Considering January to June).

Table 1:1 Disconnections by CEB from Jan to Dec in 2023

Tariff Category	Total Disconnections	Monthly Average Disconnection	Daily Average Disconnection	No. of Customers	Annual Disconnection % from tariff category Customers (%)	Annual Disconnection % from total Customers (%)
Domestic	793,192	66,099	2,173	6,058,784	13	11
General Purpose	152,475	12,706	418	880,103	17	2
Government	1,239	103	3	75,262	2	0
Industrial	18,230	1,519	50	44,002	41	0
Religious	5,748	479	16	9,708	59	0
Hotel	49	4	0	685	7	0
Total	970,933	80,911	2,660	7,068,544	14	14

1. Disconnection Analysis

1.1 Disconnections in 2023 by CEB

The data shows that 970,933 customers faced disconnections in 2023, with an average of 80,911 disconnections per month or 2,660 per day. This represents 14% of the total consumer base. The distribution of disconnections across categories reveals the affordability differences among consumer groups (Table 1:1).

Industrial and Religious Consumers experienced the highest disconnection percentages within their respective categories (41% and 59%), indicating severe challenges in managing increased costs.

Domestic consumers, while representing the majority of total disconnections (793,192), had a relatively lower category disconnection percentage (13%).

1.2 Disconnections in 2024 (January–June)

In the first half of 2024, total disconnections reached 628,286, with monthly and daily averages rising to 104,714 and 3,443, respectively—a 30% increase in average disconnections compared to 2023.

Table 1:2 Disconnections by CEB from Jan to June 2024

Tariff Category	Total	Monthly Average Disconnection	Daily Average Disconnection	No. of Customers	Annual Disconnection % from tariff category Customers (%)	Annual Disconnection % from total consumers (%)
Domestic	505,949	84,325	2,780	6,058,784	17	14
General Purpose	111,276	18,546	611	880,103	25	3
Industrial	8,579	1,430	47	75,262	23	0
Religious	2,090	348	11	44,002	10	0
Government	353	59	2	9,708	7	0
Hotel	39	7	0	685	11	0
Total	628,286	104,714	3,452	7,068,544	18	18

While disconnection percentages have decreased for some categories (e.g., Industrial and Religious consumers), the overall percentage has increased, reflecting ongoing affordability challenges.

2. LECO Data: Disconnections by LECO in 2023 and first half of 2024

LECO data provides further insights into the socio-economic burden of tariff hikes.

Table 2:1 Disconnections by LECO from Jan to Dec in 2023

Tariff Category	Total Disconnections	Monthly Average Disconnection	Daily Average Disconnection	No of Customers	Annual Disconnection % from tariff category Customers (%)	Annual Disconnection % from total consumers (%)
Domestic	80,049	6,671	219	515,298	16	13
General Purpose	17,307	1,442	47	104,253	17	3
Hotel	29	2	0	91	32	0
Religious	223	19	1	2,743	8	0
Industrial	998	83	3	3,535	28	0
Government	0	0	0	0	0	0
Total	98,606	8,217	270	625,920	16	16

Table 2:2 Disconnections by LECO from Jan to June in 2024

Tariff Category	Total Disconnections	Monthly Average Disconnection	Daily Average Disconnection	No of Customers	Annual Disconnection % from tariff category Customers (%)	Annual Disconnection % from total consumers (%)
Domestic	37,915	6,319	208	515,298	15	12
General Purpose	12,593	2,099	69	104,253	24	4
Hotel	4	1	0	91	9	0
Industrial	440	73	2	3,535	25	0
Religious	130	22	1	2,743	9	0
Government	0	0	0	0	0	0
Total	51,082	8,514	281	625,920	16	16

The Industrial category faced high disconnection rates, reflecting pressure on businesses. It shows that LECO monthly average disconnection rate has risen from 8,217 to 8,514 and daily average disconnection rate has risen from 270 to 281 when comparing in 2023 and first half of 2024. It shows that the disconnection rate is increasing by 3.81 percent when comparing 2023 and 2024. Annual disconnection percentage in 2023 is 16% and it remains the same for 2024 (Considering the first six months of 2024).

Tariff and Unit Price Trends

Between 2014 and 2023, tariff increases disproportionately affected specific consumer groups such as;

1. Industrial consumers: Unit prices rose from Rs. 14.99 (2014-Oct) to Rs. 41.20 (2023-Feb), a 175% increase.
2. Religious consumers: Unit prices escalated from Rs. 7.31 (2014-Oct) to Rs. 49.15 (2023-Feb), marking a 573% increase.

These hikes have directly contributed to higher disconnection rates, particularly among religious and industrial consumers, who often lack financial flexibility. The rising disconnections highlight persistent economic vulnerabilities, with industrial and religious consumers most affected.

These results underscore a widening affordability gap, exacerbating inequalities among consumer categories. High disconnection rates signal underlying economic distress, reflecting broader issues such as stagnant income growth and inflation.