WEST BENGAL ELECTRICITY REGULATORY COMMISSION

Ref No. WBERC/ Regulation-81/25-26/ 916 Dated, Kolkata, the 02nd February, 2026

PUBLIC NOTICE

In reference to Public Notice Nos. WBERC/Regulation-81/25-26/668 dated 13.11.2025 and WBERC/Regulation-81/25-26/780 dated 12.12.2025 of West Bengal Electricity Regulatory Commission published in the Newspaper on 14.11.2025 and 13.12.2025 respectively, inviting suggestions/objections/comments on the Draft West Bengal Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations 2025, the last date for submission as such has been further extended upto **2nd April, 2026 (3 PM)** based on the requests received from various stakeholders.

By Order of the Commission

Sd/-

Deputy Director (Engineering)

Place: Kolkata

Date : 02nd February, 2026

Tel : (033) 2962 3756 Plot No : AH/5 (2nd and 4th Floor), Premises No : MAR 16-1111 Email: wberc99@gmail.com/cp-wberc@gov.in
Fax : (033) 2962 3757 Action Area-1A , New Town, Kolkata - 700163 Website: www.wberc. gov.in

WEST BENGAL ELECTRICITY REGULATORY COMMISSION

Ref No. WBERC/ Regulation-81/25-26/780 **Dated, Kolkata, the 12th December, 2025**

PUBLIC NOTICE

In reference to Public Notice No. WBERC/Regulation-81/25-26/668 dated 13.11.2025 of West Bengal Electricity Regulatory Commission published in the Newspaper on 14.11.2025, inviting suggestions/objections/comments on the Draft West Bengal Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations 2025, the last date for submission as such has been extended upto **2nd February, 2026 (3 PM).**

By Order of the Commission

Sd/-

Deputy Director (Engineering)

Place : Kolkata

Date : 12th December, 2025

Tel : (033) 2962 3756
Fax : (033) 2962 3757
Plot No : AH/5 (2nd and 4th Floor), Premises No : MAR 16-1111
Action Area-1A , New Town, Kolkata - 700163
Email: wberc99@gmail.com/cp-wberc@gov.in
Website: www.wberc.gov.in

WEST BENGAL ELECTRICITY REGULATORY COMMISSION

Ref No. WBERC/ Regulation-81/25-26/ **Dated, Kolkata, the 13th November, 2025**

PUBLIC NOTICE

Subject : Notice Inviting Comments/ Suggestions/ Objections on Draft West Bengal Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2025

The West Bengal Electricity Regulatory Commission has brought out the Draft West Bengal Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2025 which is available at **www.wberc.gov.in**.

All stakeholders / interested persons may submit Comments/ Suggestions/ Objections on the draft to West Bengal Electricity Regulatory Commission at Plot No : AH/5 (2nd and 4th Floor) Premises No : MAR 16-1111, Action Area – 1A, New Town, Kolkata – 700 163 by **12th December, 2025 (3 P.M).**

By Order of the Commission

Sd/-

Deputy Director (Engineering)

Place : Kolkata

Date : 13th November, 2025

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WEST BENGAL ELECTRICITY REGULATORY COMMISSION

NOTIFICATION

No. ../WBERC Kolkata, the ………,2025.

In exercise of the powers conferred by sub-sections (1) of section 181, clause (o), (u), (y), (zd), (ze), (zf), (zg), (zh) and (zp) of sub-section (2) of section 181 read with section 41, 45, 51,61, 62, 63, 64, 65 and sub-section (1) of section 86 of the Electricity Act, 2003 (36 of 2003) and all powers enabling on that behalf and in supersession of the Notification No. 48/WBERC dated 25th April 2011 published in the *Kolkata Gazette, Extraordinary*, with all subsequent amendments, the West Bengal Electricity Regulatory Commission (WBERC) hereby makes the following regulations.

CHAPTER – 1: GENERAL

1. Short title, extent, applicability and commencement.

1.1 These regulations may be called the West Bengal Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2025.

1.2 These regulations shall extend to the whole of the State of West Bengal.

1.3 These regulations shall be applicable to all existing and future Generating Companies, Transmission Licensees and Distribution Licensees for the determination of Aggregate Revenue Requirement, Tariff, Mid-term Review, Truing-up, and all other matters covered under these Regulations, with effect from 1st April 2026 onwards.

1.4 These regulations shall be applicable in all cases where a Generating Company has the arrangement for supply of coal or lignite from the integrated mine(s) allocated to it, for one or more of its specified end-use generating stations, whose tariff is required to be determined by the Commission under Section 62 of the Act read with Section 86 thereof.

1.5 These regulations shall not apply to the following cases:

(i) Generating station of transmission licensee whose tariff has been discovered through competitive bidding in accordance with the guidelines issued by the central government and adopted by this Commission under section 63 of the Act.

(ii) Generating stations based on renewable source of energy or cogeneration whose tariff is determined or ceiling tariff is specified under West Bengal Electricity Regulatory Commission (Cogeneration and Generation of Electricity from Renewable Sources of Energy) Regulations, 2013 or any other regulations framed subsequently which will be the replacement of the said regulations.

1.6 These Regulations shall come into force from the date of their publication in the Official Gazette:

Provided that matters relating to determination of Annual Performance Review and any review pertaining to the period upto March 31st, 2026, shall be governed by the provisions of the then prevailing WBERC Tariff Regulations applicable at that time.

2. Definitions.

2.1 In these regulations, unless the context otherwise requires:

(i) "Act" means the Electricity Act, 2003 (36 of 2003);

(ii) "Accounts" means regulatory accounts as may be specified by the Commission and till such time these are specified by the Commission, the said accounts shall be the accounts as maintained in accordance with the Companies Act, 2013 or the relevant statutes or repealed statutes under which the licensee or the generating company is incorporated or created but subject to such deviations as specified in these regulations;

(iii) "Accounting Statement" means for each financial year, the following statements, together with notes thereto, incorporating modifications required under these regulations and such other supporting statements and information as the Commission may direct from time to time;

(a) Balance sheet, as at the end of the financial year, prepared in accordance with the statute of incorporation;
(b) Profit and loss account, prepared in accordance with the statute of incorporation;
(c) Cash flow statement for the financial year;
(d) A statement of changes in equity;
(e) An explanatory note annexed to, or forming part of, any document referred to in sub-clause (a) to sub-clause (d) above
(f) Report of the auditors;
(g) Reconciliation statement, duly certified by the auditor, showing the reconciliation between the total expenses, income, assets and liabilities, of the entity as a Company / Corporation and the expenses, income, assets and liabilities, separately for each business regulated by the Commission and unregulated business operations;
(h) Cost records prescribed under the Companies (cost records and audit) Rules, 2014 along with Cost Audit Report under Section 148 of Companies Act, 2013; together with notes thereto, and such other supporting statements and information as the Commission may direct from time to time;
(i) For Damodar Valley Corporation (DVC) the cost records as per the provisions of DVC Act 1948, shall be submitted;

(iv) "Additional Capital Expenditure" means the capital expenditure incurred, or projected to be incurred after the date of commercial operation of the project by the generating company or the licensee, as the case may be, in accordance with the provisions of these regulations.

(v) "Additional Capitalization" means the additional capital expenditure admitted by the Commission after prudence check, in accordance with these regulations.

(vi) "Admitted Capital Cost" means the capital cost which has been allowed by the Commission for servicing through tariff after due prudence check in accordance with the relevant tariff regulations.

(vii) "Aggregate Revenue Requirement" or "ARR" means the revenue requirement for activities related to the business of electricity of a licensee or a generating company, as the case may be, for recovery of allowable expenses, return on equity and other permitted allowances, for any specific period as a part of revenue recoverable through tariff in accordance with these regulations;

(viii) "Allocation Statement" means for each financial year, a statement in respect of each of the separate businesses of the licensee, showing the amounts of any cost, revenue, asset, liability, reserve or provision, which has been either;

(a) Charged from or to each such separate business together with a description of the basis of that charge; or

(b) Determined by apportionment or allocation between the core business and every other separate business of the licensee, together with a description of the basis of the apportionment or allocation;

(ix) "Allotted Transmission Capacity" means the power-transfer in MW between the specified point(s) of injection and point(s) of drawal allowed to a long-term customer on the intra-state transmission system under the normal circumstances and the expression "allotment of transmission capacity" shall be construed accordingly;

(x) "Annexure" or "Annex" means the annexure to these regulations;

(xi) "Annual Target Quantity" or 'ATQ' in respect of an integrated mine(s) means the quantity of coal or lignite to be extracted during a year from such integrated mine(s) corresponding to 85% of the quantity specified in the Mining Plan;

(xii) "Ancillary Services" or 'AS' means the same as defined in the West Bengal Electricity Regulatory Commission (Ancillary Services) Regulations 2023 or its subsequent Amendment, if any;

(xiii) "Area Load Despatch Centre" or "ALDC" means the area load despatch centre as defined in the State Grid Code;

(xiv) "Auditor" means an auditor appointed by a generating company or a licensee, as the case may be, in accordance with the provisions of sections 224, 233B and 619 of the Companies Act, 1956 (1 of 1956), as amended from time to time or Chapter X of the Companies Act, 2013 (18 of 2013) or any other law for the time being in force

(xv) "Auxiliary Energy Consumption" or "AUX" in relation to a period in case of a generating station means the quantum of energy consumed by auxiliary equipment of the generating station, such as the equipment being used for the purpose of operating plant and machinery including switchyard of the generating station and the transformer losses within the generating station, measured through meters and expressed as a percentage of the sum of gross energy generated at the generator terminals of all the units of the generating station;

Provided that auxiliary energy consumption shall not include energy consumed for the supply of power to the housing colony and other facilities at the generating station and the power consumed for construction works at the generating station and integrated mine(s);

Provided further that auxiliary energy consumption for compliance with revised emission standards, sewage treatment plant and external coal handling plant (jetty and associated infrastructure) shall be considered separately.

(xvi) "Auxiliary Energy Consumption for emission control system" or "AUXe" in relation to a period in the case of coal or lignite based thermal generating station means the quantum of energy consumed by auxiliary equipment of the emission control system of the coal or lignite based thermal generating station in addition to the auxiliary energy consumption under clause (xv) of this Regulation;

(xvii) "Availability" in terms of Availability Based Tariff in relation to

a) thermal generating station/unit for any period means the average of the daily average declared capacities as certified by SLDC for all the days during that period expressed as a percentage of the installed capacity (in MW) of the generating station/unit minus normative auxiliary energy consumption and normative auxiliary energy consumption for emission control system, as specified in these regulations and shall be computed in accordance with the following formula;

$$Availability = 1000\ x \sum_{i=1}^{N} \frac{DC_i}{\{N\ x\ IC\ x\ (100 - AUX_n - AUXe_n)\}}\ \%$$

Where -

N = Number of time blocks in the given period as may be decided by the Commission from time to time;

DC_i = Average Declared ex-bus Capacity in MW for the i^{th} time block in such period;

IC = Installed Capacity of the generating station in MW;

AUX_n = Normative auxiliary consumption as a percentage of gross generation;

$AUXe_n$= Normative auxiliary consumption for Emission Control System as a percentage of gross generation;

b) transmission system for a given period means the time in hours in that period the transmission system is capable of transmitting electricity at its rated voltage expressed in percentage of total hours in the given period, and shall be certified by SLDC and computed as provided in Schedule 7 of these Regulations;

(xviii) “Balancing and Settlement Code” refers to the West Bengal Electricity Regulatory Commission (Balancing and Settlement Code) Regulations, 2021;

(xix) “Bank Rate” means the one-year Marginal cost of the lending rate as specified by the State Bank of India from time to time or any replacement thereof for the time being in force plus 100 basis points;

(xx) “Banking/swapping” means an arrangement under any agreement or order where a licensee supplies power to a person other than own consumer or a licensee with a condition that the said recipient will reciprocate such supply by returning in a manner as will be determined by the terms and conditions of the agreement or order a certain quantum of power to the supplier as committed in lieu of the power already supplied to him.

(xxi) “Base Year” means the financial year immediately preceding the first year of the control period;

(xxii) “Base rate of Delayed Payment Surcharge” shall means, the one-year Marginal Cost of Funds-based Lending Rate ('MCLR') as declared by the State Bank of India, as applicable on the 1st April of the financial year in which the period lies, plus five percent and in the absence of MCLR, any other arrangement that substitutes it, which the Central Government may, by notification, in the Official Gazette specify:

Provided that if the period of default lies in two or more financial years, the Base Rate of Delayed Payment Surcharge shall be calculated separately for the periods falling in different years;

(xxiii) "Beneficiary" in relation to a generating station means means a distribution licensee who is purchasing electricity generated at such generating station by entering into a Power Purchase Agreement either directly or through a trading licensee on payment of capacity charges and energy charges:

Provided that where the distribution licensee is procuring power through a trading licensee, the arrangement shall be secured by the trading licensee through back to back power purchase agreement and power sale agreement:

Provided further that beneficiary shall also include any person who has been allocated capacity in any inter-State generating station by the Government of India;

(xxiv) "Captive Generating Plant" means the Captive Generating Plant as defined in the Act and qualifies as per the provisions of the Electricity Rules, 2005 or any subsequent amendment or replacement of the said rules;

(xxv) "Capital Expenditure" means the fund, where the equity or debt or both, actually deployed and paid in cash or cash equivalent for creation or acquisition of a useful asset and does not include commitments or liabilities for which no payment has been released.

(xxvi) "CERC" means Central Electricity Regulatory Commission established undersection 76 of the Act;

(xxvii) 'Change in law' means the occurrence of any of the following events:

(a) enactment, bringing into effect or promulgation of any new Indian law; or

(b) adoption, amendment, modification, repeal or re-enactment of any existing Indian law; or

(c) change in interpretation or application of any Indian law by a competent court, Tribunal or Indian Governmental Instrumentality which is the final authority under law for such interpretation or application; or

(d) change by any competent statutory authority in any condition or covenant of any consent or clearances or approval or licence available or obtained for the project; or

(e) coming into force or change in any bilateral or multilateral agreement or treaty between the Government of India and any other Sovereign Government having implications for the generating station or the transmission system regulated under these regulations.

(xxviii) "Commission" means the West Bengal Electricity Regulatory Commission constituted under section 82 of the Act;

(xxix) "Competitive Bidding" means a transparent process for procurement of equipment, services and works in which bids are invited by open advertisement covering the scope and specifications of the equipment, services and works required for the project, and the terms and conditions of the proposed contract as well as the criteria by which bids shall be evaluated, and shall include domestic competitive bidding and international competitive bidding.

(xxx) "Conduct of Business Regulations" means such regulations as may be specified by the Commission under sub-sections (1) and (4) of section 91, sub-section (1) of section 92, sub-section (1) of section 127, section 130 and sub-section (1) of section 181 read with clauses (zl), (zn), (zo) and (zp) of sub-section (2) of section 181 of the Act;

(xxxi) "Control Period" means a period consisting of five (05) years, for which the licensee or generating company will file the application for tariff determination under the multi-year tariff framework;

(xxxii) "Controllable factor" means those elements of ARR for which the entitlement is controllable or the expenditure can be controlled by the concerned licensee or generating company for whom ARR is determined at the amount for such element permitted by the

Commission in the tariff order subject to specific conditions as permitted under these regulations;

(xxxiii) “Core Business” means the electricity generation business for a generating company or the business of transmission or distribution of electricity as per license of the licensee excluding embedded generation business, if any;

(xxxiv) “Cut-off Date” means the last day of the financial year closing after thirty-six months from the date of commercial operation of the project, except in case of integrated mine(s);

(xxxv) “Date of commercial operation” or COD means

(a) In relation to a unit, the date declared by the generator after demonstrating the maximum continuous rating (MCR) or installed capacity (IC) through a successful trial run after notice to the beneficiaries following the methodology and manner specified in Schedule-1 of these Regulations;

(b) In relation to a generating station, the date of commercial operation of the last unit or block of the generating station in accordance with clause (a) above;

(c) In case of (a) above, the date of commercial operation shall not be more than 90 days from the date of unit synchronization to the grid;

(d) In relation to an emission control system of generating station, or a network element or communication element of Transmission and Distribution system, the date of put to use in regular service after successful trial operation following the methodology specified under Schedule-1 of these regulations;

(e) In relation to integrated mine the date as specified in Schedule -1 of these regulations;

(xxxvi) ‘Date of commencement of production” in respect of integrated mine(s) means the date of touching of coal or lignite, as the case may be, as declared by the generating company;

(xxxvii) "Date of Synchronization" means the date on which synchronization as defined in clause (cxl) of this regulation has taken place with the bus bar.

(xxxviii) 'Day' means a calendar day consisting of 24 hours period starting at 0000 hours;

(xxxix) "Declared Capacity" or "DC" in relation to a generating station means the capability to deliver ex-bus electricity in MW declared by such generating station in relation to any time-block of the day as defined in the State Grid Code or whole of the day, duly taking into account the availability of fuel or water, and subject to further qualification in these regulations;

(xl) "De-capitalization" for the purpose of the tariff under these regulations, means a reduction in Gross Fixed Assets of the project as admitted by the Commission corresponding to the inter-unit transfer of assets or the assets taken out from service;

(xli) 'De-commissioning" means removal from service of a generating station or a unit thereof or transmission or distribution system including communication system or element thereof, after it is certified by the Central Electricity Authority or any other authorized agency, either on its own or on an application made by the project developer or the beneficiaries or both, that the project cannot be operated due to non-performance of the assets on account of technological obsolescence or uneconomic operation or due to environmental concerns or safety issues or a combination of these factors;

(xlii) "Design Energy" in relation to a hydro-generating station means the quantum of energy, which could be generated in a 90 per cent dependable year with 95 per cent installed capacity of the generating station;

(xliii) "Distribution Business" means the business of operating and maintaining a distribution system for supplying electricity in the area of supply of a distribution licensee;

(xliv) "Distribution Licensee" means a person exempted under section 13 of the Act within the State or a person who has been granted a licence by the Commission under section 14 of the Act including a deemed licensee under the purview of the Commission in pursuance to first, third, fourth proviso to section 14 of the Act and licensee created in accordance with fifth proviso to section 14 of the Act to distribute electricity within its area of supply;

(xlv) “Distribution Loss” means the difference between the energy inputs in the distribution system and the sum of energy sold, energy consumed by the licensee for its own purposes in its own premises within its area of supply and the energy delivered at the drawal point of the open access customer after wheeling by the licensee including normative technical loss of energy due to wheeling as per Open Access Regulations;

(xlvi) “Distribution system user” means a person who has been allowed open access to the distribution system of a Distribution Licensee and the consumer or a class of consumers allowed to receive supply from a person other than a Distribution Licensee;

(xlvii) “DPR” means the detailed project report;

(xlviii) “Detailed Project Report Scheme” (or "DPR Scheme") means a capital expenditure Scheme with projected capital cost exceeding the limits specified in the ‘Capital Expenditure Approval Framework’ as provided in Schedule-3 to these Regulations, for in-principle clearance of proposed Investment schemes or any such amount stipulated by the Commission, for which the Generating Company or Transmission Licensee or Distribution Licensee, as the case may be, is required to obtain prior in-principle approval by submitting a Detailed Project Report (DPR) in accordance with above said framework;

(xlviia) 'EHT or EHV' means the same as defined in State Grid Code;

(xlix) “Element” means an asset which has been distinctively defined under the scope of the transmission or distribution project in the Investment Approval, such as transmission/ distribution lines, including line bays and line reactors, substations, bays, compensation devices, Transformers which can be put to use.

(l) "Ensuing Year" means the year(s) in the control period for which applicable tariff and charge would be determined by the Commission in subsequent years following the base year in the control period and one, two, three, four, five in reference to ensuing year means first, second, third, fourth and fifth years respectively immediately subsequent to such base year;

(li) “Emission control system” means a set of equipment or devices required to be installed in a coal or lignite based thermal generating station or unit thereof to meet the revised emission standards;

(lii) “ERC” or “Expected Revenue from Charges” means the expected revenue from charges and tariff that a licensee or a generating company is permitted to recoverpursuant to these regulations;

(liii) “Existing Project” means the project declared under commercial operation from a date prior to 01.04.2026;

(liv) “Existing Generating Station” means a generating station, which had a date of commercial operation prior to 01.04.2026;

(lv) “Expansion project” shall include any addition of new capacity to the existing generating station or augmentation of the transmission / distribution system of existing project, as the case may be;

(lvi) 'Expenditure Incurred' in relation to capital cost, means the fund, whether the equity or debt or both, actually deployed and paid in cash or cash equivalent, for the creation or acquisition of a useful asset and does not include commitments or liabilities for which no payment has been released;

(lvii) 'Extended Life' means the life of a generating station or unit thereof or transmission / distribution system or element thereof beyond the period of useful or operational life, as may be determined by the Commission on case to case basis;

(lviii) “Fees Regulations” means such regulations as may be specified by the Commission under clause (g) of sub-section (1) of section 86 of the Act;

(lix) “Fixed Cost” means ARR or revenue recoverable through tariff reduced by corresponding variable cost for any activity or as a whole of the licensee or a generating station, as the case may be;

(lx) “Financial Statement” shall have the same meaning as defined in clause (iii) of this regulation;

(lxi) “Force Majeure” for the purpose of these regulations means the events or circumstances or combination of events or circumstances, including those stated below, which prevent the generating company or the licensee from completing or operating the project, and only if such events or circumstances are not within the control of the generating company or the licensee and could not have been avoided, had the generating company or the licensee taken reasonable care or complied with prudent utility practices:

(a) Act of God including lightning, drought, fire and explosion, earthquake, volcanic eruption, landslide, flood, cyclone, typhoon, tornado, geological surprises, or exceptionally adverse weather conditions which are in excess of the statistical measures for the last hundred years; or

(b) Any act of war, invasion, armed conflict or act of a foreign enemy, blockade, embargo, revolution, riot, insurrection, terrorist or military action; or

(c) Strikes and industrial disturbances having a State-wide / nation-wide impact or extensive impact in the area of supply of a Licensee, but excluding strikes and industrial disturbances in the Generating Company's or Licensee's own organisation; or

(d) Delay in obtaining statutory approval for the project except where the delay is attributable to the project developer;

(lxii) "Fuel Cost" means all expenditure related to procurement of fuel that is required for combustion in thermal generating station for generation of electricity following the principles specified in these regulations;

(lxiii) 'Fuel Supply Agreement' means the agreement executed between the generating company and fuel supplier for the generation and supply of electricity to the beneficiaries;

(lxiv) "Generating Company" means any company or body corporate or association or body of individuals, whether incorporated or not, or artificial juridical person, which owns or operates or maintains a generating station and excludes those generating companies covered under clauses (a) and (b) of sub-section (1) of section 79 of the Act or lying outside India or outside the state, except those generating companies whose inter-state supply to any licensee is under the purview of the Commission under sub-section (5) of section 64 of the Act;

(lxv) "Generation Business" means the business of production of electricity from a generating station for the purpose of giving supply to any person or enabling a supply to be so given;

(lxvi) "Generating station" shall have the same meaning as defined under sub-Section 30 of Section 2 of the Act and, for the purpose of these regulations, shall also include stages or blocks or units of a generating station

(lxvii) 'Generating Unit' or 'Unit' in relation to a thermal generating station (other than combined cycle thermal generating station) means steam generator, turbine-generator and auxiliaries, or in relation to a combined cycle thermal generating station, means turbine-generator and auxiliaries or combustion turbine-generator, associated waste heat recovery boiler, connected steam turbine- generator and auxiliaries, and in relation to a hydro generating station means turbine-generator and its auxiliaries;

(lxviii) "Government" or "State Government" means the Government of West Bengal;

(lxix) "Gross Calorific Value" or GCV in relation to a thermal power generating station means the heat produced in Kilo Calorie by the complete combustion of one Kg of solid fuel or one litre of liquid fuel or one standard cubic meter of gaseous fuel, as the case may be;

(lxa) "GCV as received" means the GCV of coal as measured at the unloading point of the thermal generating station through collection, preparation and testing of samples from the loaded wagons, trucks, ropeways, Merry-Go-Round (MGR), belt conveyors and ships in accordance with the IS 436 (Part-1/ Section 1)- 1964 and clause 6.2 of IS 1350 (Part-II)-1970:

Provided that the measurement of coal shall be carried out through sampling by a third party to be appointed by the generating companies from the list empaneled or approved by the Ministry of Coal, Government of India/ Coal India Limited:

Provided further that samples of coal shall be collected either manually or through hydraulic augur or through any other method considered suitable keeping in view the safety of personnel and equipment:

Provided also that the generating companies may adopt any advanced technology for collection, preparation and testing of samples for measurement of GCV in a fair and transparent manner:

Provided also that, the generating companies shall take all measures to avoid grade slippage and if any grade slippage occurs, generating company shall take up the issue with coal supplier as per the Fuel supply agreement for necessary adjustment. However, for computation of energy charge 'as received GCV' shall be restricted upto the 'as billed GCV' of the coal minus 300 kCal/kg, subject to other provisions of these regulations.

(lxx) "Gross Station Heat Rate" means the heat energy input in Kilo Calorie for a generating station required to generate one kWh of electrical energy at generatorterminals;

(lxxi) 'HT or HV' means the same as defined in State Grid Code;

(lxxii) "Incidental Services" means such services, other than direct utilization of the assets, which are explored for generating additional income such as advertisements on bill face, bill boards and hoardings set up in establishments, utilization of optical fiber, etc. by using the business processes of core business of the licensee;

(lxxiii) "Indian Governmental Instrumentality" means the Government of India, Governments of State (where the project is located) and any ministry or department or board or agency controlled by the Government of India or the Government of State where the project is located, or quasi-judicial authority constituted under the relevant statutes in India;

(lxxiv) "Infirm Power" means electricity injected into the grid prior to the date of commercial operation of a unit of the generating station;

(lxxv) "Input Price" means the price of coal or the price of lignite (including transfer price of lignite in respect of existing lignite mines) sourced from the integrated mines at which the coal or lignite is transferred to the generating station for the purpose of computing the energy charges for generation and supply of electricity to the beneficiaries and determined in accordance with Chapter - 9 of these regulations;

(lxxvi) “Installed Capacity” or “IC” means the summation of the nameplate capacities of all the units of the generating station or the capacity of the generating station (reckoned at the generator terminals) as already considered by the Commission in its last tariff order, or as approved by the Commission from time to time;

(lxxvii) “Integrated Mine” means the captive mine (allocated for use in one or more identified generating stations) or basket mine (allocated to a generating company for use in any of its generating stations) or both being developed by the generating company or its affiliate for supply of coal or lignite to one or more specified end use generating stations for generation and sale of electricity to the beneficiaries;

Explanation: Affiliate shall mean a company that is directly controlled and owned by a generating company having at least twenty six percent (26%) of the voting rights of the entity.

(lxxviii) “Intra-State Transmission System” or “InSTS” means any system for conveyance of electricity by transmission lines within the area of the State of West Bengal, and includes all transmission lines, sub-stations and associated equipment of Transmission Licensees in the State:

Provided that the definition of point of separation between a Transmission System and distribution system and between a Generating Station and Transmission System shall be guided by the Regulations notified by the Central Electricity Authority under clause (b) of Section 73 of the Act;

(lxxix) "Licensee” means a person who has been granted licence by the Commission under section 14 of the Act for distribution and / or transmission of electricity and also includes a deemed licensee under the purview of the Commission in pursuance to first to fifth proviso to section 14 of the Act or persons exempted under section 13 of the Act within the State;

(lxxx) “Loading Point” in respect of integrated mine(s) means the location of railway siding or silo or the coal handling plant or such other arrangements like a conveyor belt, whichever is nearest to the mine, for despatch of coal or lignite, as the case may be;

(lxxxi) "Long-term Power procurement" means Procurement of power under any arrangement or agreement with a term or duration exceeding seven years but not exceeding twenty-five years;

(lxxxii) "Long-Term Transmission Customer" means transmission system user or intending transmission system user who is or to be long term customer as per the Open Access Regulations;

(lxxxiii) 'LT or LV' means the same as defined in the State Grid Code;

(lxxxiv) "Maximum Available Capacity" –

a) for run-of-river hydro generating station with pondage and storage type or pumped storage hydro-generating stations means the maximum capacity in MW that the generating station can generate with all units running, under the prevailing conditions of water levels and flows available for usage over the peaking hours of next day and for this purpose, the peaking hours shall be as may be scheduled by SLDC, which shall not be less than 3 (three) hours within a 24 (twenty four) hour period for which schedule is drawn;

b) for a purely run-of-river hydro-generating station means the maximum capacity in MW, the generating station can generate with all units running under the prevailing conditions of water levels and flows available for usage over the next day;

c) for a thermal generating station means, the maximum capacity in MW, the generating stations can generate with all units running under the fuel availability and equipment availability of the plant over the peaking hours of next day;

(lxxxv) "Maximum Continuous Rating" or "MCR" in relation to an unit of a thermal generating station means the maximum continuous output at the generator terminals, guaranteed by the manufacturer at rated parameters or as may be approved by the Commission from time to time, and in relation to a unit or blockof a combined cycle thermal generating station means the maximum continuous output at the generator terminals, guaranteed by the manufacturer with water / steam injection (if applicable) and corrected to 50 Hz grid frequency and specific site conditions or as may be approved by the Commission from time to time;

(lxxxvi) "Medium Term Power Procurement" means Procurement of power under any arrangement or agreement with a term or duration exceeding one year but not exceeding seven years;

(lxxxvii) Mid-Term Review" means a review to be undertaken in accordance with the clause (iii)(c) of Regulation 4.2 and Regulation 7 of these regulations

(lxxxviii) "Mine Infrastructure" shall include assets of the integrated mine(s) such as tangible assets used for mining operations, being civil works, workshops, immovable mining equipment, foundations, embankments, pavements, electrical systems, communication systems, relief centres, site administrative offices, fixed installations, handling arrangements, crushing and conveying systems, railway sidings, pits, shafts, inclines, underground transport systems, hauling systems (except movable equipment unless the same is embedded in land for permanent beneficial enjoyment thereof), land demarcated for afforestation and land for rehabilitation and resettlement of persons affected by mining operations under the relevant law;

(lxxxix) "Mining Plan" or "Mine Plan" in respect of integrated mine(s) means a plan prepared in accordance with the Guidelines for Preparation, Formulation, Submission, Processing, Scrutiny, Approval and Revision of Mining Plan for the coal and lignite block issued by the Ministry of Coal, Government of India as amended from time to time or provisions of the Mineral Concession Rules, 1960, as amended from time to time and approved under clause (b) of sub-section (2) of section 5 of the Mines and Minerals (Development and Rehabilitation) Act, 1957 by the Central Government or by the State Government, as the case may be;

(xc) "Modalities of Tariff Regulations" means the West Bengal Electricity Regulatory Commission (Modalities of Tariff Determination) Regulations, 2023 and its amendments from time to time;

(xci) 'MT or MV' means the same as defined in the State Grid Code;

(xcii) "New Generating Station" means a generating station with a date of commercial operation on or after 01.04.2026;

(xciii) "New Project" means the project declared under commercial operation on or after 01.04.2026;

(xciv) "Non DPR Scheme" means a capital expenditure Scheme with projected capital cost within the limits specified in the guidelines for in-principle clearance of proposed Investment schemes or any such amount stipulated by the Commission, for which the Generating Company or Transmission Licensee or Distribution Licensee, as the case may be, is not required to obtain prior in-principle approval of the Commission;

(xcv) "Non-Pit head Generating Station" or 'Non-Pit Head Power Plant' means coal and lignite based generating stations other than Pit Head Generating Stations;

(xcvi) "Non-Tariff Income" means income relating to the core-business other than from tariff, excluding any income from the following activities: -

a) Other business, if applicable;

b) Incidental Services, if applicable;

c) Wheeling of electricity, if any;

d) Receipts on account of cross-subsidy surcharge and additionalsurcharges on charges of wheeling;

e) Income from Deviation Settlement Mechanism;

(xcvii) "Officer" means an officer of the Commission;

(xcviii) "Open Access Agreement" means an agreement entered into by an open access customer with transmission licensees, distribution licensees and generators as specified in open access regulations;

(xcix) "Open Access Customer" means the person as defined in open access regulations;

(c) “Open Access Regulations” refers to West Bengal Electricity Regulatory Commission (Open Access) Regulations, 2022;

(ci) “Operation and Maintenance expenses” or “O&M expenses” means the expenditure incurred on operation and maintenance of a generating station or licensee and includes the expenditure on manpower, repairs, spares, consumables, insurance, overheads and other expenses incidental to the business as specified in regulation 36 of these regulations;

(cii) “Original Project Cost” means the actual capital expenditure incurred on the project as per the original scope up to cut-off date and as admitted by the Commission;

(ciii) “Other Business” means any business engaged in by a transmission licensee referred to in section 41 of the Act or by a distribution licensee referred to in section 51 of the Act for optimum utilization of the assets related to core business of such transmission licensee or for such distribution licensee, as the case may be;

(civ) “Peak Rated Capacity” in respect of integrated mine(s) means the peak rated capacity of the mine, as specified in the Mining Plan;

(cv) “Pit-head Generating Station' or 'Pit Head Power Plant' means as defined under The Environment (Protection) Rules, 1986 or any subsequent amendment thereof;

(cvi) “Plant Availability Factor” or “PAF” in relation to a Generating station for any period means the average of the daily average declared capacities (DCs), as certified by SLDC, for all the days during the period expressed as a percentage of the installed capacity in MW less the normative auxiliary energy consumption including for emission control system, wherever applicable;

(cvii) ‘Plant Load Factor” or “PLF” in relation to thermal generating station or unit thereof for a given period means the total sent out energy corresponding to scheduled generation during the period, expressed as a percentage of sent out energy corresponding to installed capacity in that period and shall be computed in accordance with the following formula:

$$PLF = 1000\ x \sum_{i=1}^{N} \frac{SG_i}{\{N\ x\ IC\ x\ (100 - AUX_n - AUXen)\}}\ \%$$

Where,

IC = Installed Capacity of the generating station or unit in MW,

SGi = Scheduled Generation in MW for the i^{th} time block of the period,

N = Number of time blocks during the period,

AUXn = Normative auxiliary energy consumption as a percentage of gross energy generation, and

AUXen = Normative auxiliary energy consumption for emission control system as a percentage of gross energy generation, wherever applicable.

Provided further that, where a generating station has contracted a part of its installed capacity with the beneficiary, PLF shall be computed based on such contracted capacity in place of the installed capacity.

(cviii) "Power Purchase Agreement" or "PPA" means the commercial agreement between a licensee and a generating company or between two licensees, as the case may be, containing the terms and conditions for purchase of electricity by the licensee from the generating company or from another licensee, as the case may be.

(cix) "Previous Year" means four years immediately prior to base year and one, two, three, four in reference to previous year mean first, second, third and fourth years respectively immediately preceding to such base year;

(cx) "Prudence Check" means scrutiny of the reasonableness of any cost or expenditure incurred or proposed to be incurred, financing plan, use of efficient technology, cost and time over-run and such other factors as may be considered appropriate by the Commission for investment approval, admitting capital cost, determination of ARR and Tariff in accordance with these Regulations;

(cxi) “Pumped Storage Hydro Generating Station” means a hydro generating station which generates power through energy stored in the form of water energy, pumped from a lower elevation reservoir to a higher elevation reservoir;

(cxii) “Rated Voltage” in relation to a transmission system means the manufacturer’s rated design voltage at which the transmission system is designed to operate, or such lower voltage at which the line is charged, for the time being, in consultation with the transmission system users;

(cxiii) “Regulations” means regulations made under the Act;

(cxiv) “Regulated Business” means any electricity business, which is regulated by the Commission;

(cxv) "Research & Development Expenditure" or "R & D Expenditure" means expenditure on the head of pilot project, research in fundamental or applied science, research in technology or engineering, survey or studies on available technology or consumer base or market base, impact assessment on environment and society, audit or survey in relation to safety, occupational health hazards, energy, grid security, and grid protection, etc.

(cxvi) “Revised Emission Standards’ in respect of thermal generating station means the revised norms notified as per Environment (Protection) Amendment Rules, 2015 or any other Rules as may be notified from time to time;

(cxvii) “Rules” means rules made under the Act;

(cxviii) “Run-of-river hydro-generating station” means a hydro-generating station, which has no upstream pondage;

(cxix) “Run-of-river hydro-generating station with pondage” means a hydro-generating station with sufficient pondage for meeting the diurnal variation of power demand;

(cxx) “Salable Energy” means the quantum of energy available for sale (ex-bus) in respect of hydro-generating station after allowing share of free energy, if any, as per agreement or government policy;

(cxxi) “Schedule” means the schedule to these regulations;

(cxxii) “Scheduled Generation” or “Scheduled Injection” for a time block or any period means the schedule of generation or injection in MW or MWh ex-bus, including the schedule for Ancillary Services, if any, given by the SLDC in accordance with the State Grid Code;

(cxxiii) “Season” means a block of four months;

(cxxiv) “Secretary” means the Secretary of the Commission;

(cxxv) “Short Term Power Procurement” means Procurement of power under any arrangement or agreement with a term or duration less than or equal to one year;

(cxxvi) “SLDC” means the State Load Despatch Centre established by the Government of West Bengal under sub-section (1) of section 31 of the Act;

(cxxvii) “Standards of Performance Regulations” or “SOP” means the regulations as specified by the Commission under sub-section (1) of section 57 and sub-section (1) of section 59 of the Act;

(cxxviii) “Start Date or Zero Date" means the date indicated in the Investment Approval for commencement of implementation of the project, and where no such date has been indicated, the date of Investment Approval shall be deemed to be Start Date or Zero Date;

(cxxix) “Start-up power” means the power required by any Generating Station or Captive Generating Plant for black start-up or cold start-up of the generating station;

(cxxx) “State” means the State of West Bengal;

(cxxxi) “State Grid” means the same as defined in the State Grid Code;

(cxxxii) “State Grid Code” means the regulations specified by the Commission under clause (h) of sub-section (1) of section 86;

(cxxxiii) "State Transmission System" means the state transmission system as defined in State Grid Code;

(cxxxiv) "Statutory Charges" means and includes taxes, cess, duties, royalties and other charges levied through Acts of the Parliament or State Legislatures or by Indian Government Instrumentality under relevant statutes;

(cxxxv) "STU" means WBSETCL or any other Government Company as notified by the Government of West Bengal under sub-section (1) of section 39 of the Act;

(cxxxvi) "Storage type hydro-generating station" means a hydro-generating station associated with large storage capacity to enable variation in generation of electricity according to demand;

(cxxxvii) "Survival Power" means the power required by any generating station or Captive Generating Plant for running the auxiliary equipment of that Generating Station in hot-standby or cold-standby mode.

(cxxxviii) "Synchronization" for the purpose of these regulations means the first commissioning (except test synchronization) of an unit of a generating station for the commencement of trial run prior to date of commercial operation and thereby injecting electricity in the State Grid with full availability of all load bearing equipments and all systems of the generating station excluding the instances of test synchronization;

(cxxxix) "Tariff" means a schedule of prices payable by recipient person of electricity for supply of electricity to him or the charges payable by the person for availing specified service of wheeling or transmission of electricity which are determined under section 62 or section 64 of the Act in pursuance to these regulations;

(cxl) "Test Synchronization" means the commissioning of any unit with its full/ partial installed capacity and thereby injecting the electricity in the State Grid for the purpose of test operation of such unit;

(cxli) "Transmission Business" means the business of establishing or operating transmission lines by transmission licensee;

(cxlii) "Transmission Capacity Rights" means the right of a Transmission System User to transfer power in MW, under normal circumstances, between such points of injection and drawal as derived in terms of Regulation 76.3 of these regulations;

(cxliii) "Transmission Licensee" means a person who has been granted a licence by the Commission under section 14 of the Act including a deemed licensee under the purview of the Commission in pursuance to second, fourth proviso to section 14 of the Act and licensee created in accordance with fifth proviso to section 14 of the Act to transmit electricity;

(cxliv) "Transmission Loss" means the difference between the energy inputs in the transmission system for transmission of electricity and energy delivered by the transmission system at delivery points including auxiliary and own consumptions of the transmission licensee;

(cxlv) "Transmission System" means a transmission line with associated sub-stations ora group of transmission lines inter-connected together along with associated sub-stations and the term includes equipment associated with transmission lines and sub-stations;

(cxlvi) "Transmission System User" for the purpose of these Regulations means the Distribution Licensees and long-term Open Access Users;

(cxlvii) 'Uncontrollable factor' means those elements of ARR for which expenditure depends on certain external factors and which are not fully controllable by the licensee or generating company;

(cxlviii) "Unit" in relation to a thermal power generating station means steam generator, turbine-generator and auxiliaries, or in relation to a combined cycle thermalpower generating station, means turbine-generator and auxiliaries;

(cxlix) "Unloading point" means the point within the premises of the coal or lignite based thermal generating station where the coal or lignite is unloaded from the rake or truck or any other mode of transport;

(cl) “Useful Life” in relation to a unit of a generating station, integrated mines, transmission / distribution system and communication system from the date of commercial operation shall mean the following:

(a)	Coal/Lignite based thermal generating station	25 years
(b)	Gas/Liquid fuel based thermal generating station	25 years
(c)	AC and DC sub-station	25 years
(d)	Gas Insulated Substation (GIS)	25 years
(e)	Hydro generating station including pumped storage hydro generating stations	40 years
(f)	Transmission line (including HVAC & HVDC)	35 years
(g)	Distribution line (upto 33kV)	25 years
(h)	Buildings – Offices & showrooms	50 years
(i)	Roads other than kutcha roads	50 years
(j)	Office furniture & equipments	15 years
(k)	Optical Ground Wire (OPGW)	15 years
(l)	Electronic meters, IT system, SCADA and Communication system excluding OPGW	7 years
(m)	Batteries, self-propelled vehicles, software, temporary wooden structure	5 years
(i)	Integrated mine(s)	As per the Mining Plan

Useful life of Generating station, sub-station, transmission line and distribution line, etc. includes all major items unless explicitly mentioned above.

(cli) “Variable Cost" means the fuel cost and/or power purchase cost portion of ARRor revenue recoverable through tariff for all or any of the activities, as the case may be, of a licensee and/or generating station(s) or generating company, as thecase may be;

(clii) “WBERC” means the West Bengal Electricity Regulatory Commission;

(cliii) “Year" means a financial year beginning on 1st April and ending on 31st March.

2.1.1 Words and expressions used in these regulations and not defined shall have the meanings respectively assigned to them in the Act or the Regulations made thereunder by the Commission.

3. Scope of the Regulations:

3.1 The Commission shall determine the Aggregate Revenue Requirement and Tariff, including terms and conditions thereof, in accordance with these Regulations, for all matters under its jurisdiction as per the Act and in conformity to the Modalities of Tariff Regulations, including the following:

i Supply of electricity by a generating company within the state to a distribution licensee within the state under section 62 of the Act:

Provided that the Commission may, in case of shortage of supply of electricity, fix the minimum and maximum ceiling of tariff for sale or purchase of electricity in pursuance of an agreement entered into betweena generating company and a licensee or between licensees, for a period not exceeding one year;

ii Intra-State transmission of electricity within the state for intra-state transmission system under section 62 of the Act;

iii Rates and charges for use of intervening transmission facilities, where these cannot be mutually agreed upon by the licensees within the state under section 36 of the Act;

iv Wheeling of electricity within the state under section 62 of the Act;

v Retail sale of electricity within the state under section 62 of the Act:

Provided that in case of distribution of electricity in the same area by two or more licensees, the Commission may, for promoting competition among licensees, fix only maximum ceiling of tariff for retail sale of electricity:

Provided also that where the Commission has allowed open access to certain consumers under section 42, such consumers, notwithstanding the provisions contained in clause (d) of sub-section (1) of section 62 of the Act,may enter into an agreement with any person for supply or purchase of electricity on such terms and conditions (including tariff) as may be agreed upon by them;

Provided further that where the Commission has permitted open access to any consumer or a category of consumers under section 42 of the Act, the Commission shall determine only the wheeling charges and surcharge thereon, if any, in pursuance to the proviso to clause (a) of sub-section (1) of section 86 of the Act, and no tariff for such consumer shall be determined by the Commission under these regulations for the part corresponding to Open Access mode.

3.2 The Commission in pursuance of sub-section (5) of section 64 of the Act, upon application made to it by the parties intending to undertake inter-state supply, transmission or wheeling of electricity involving the territories of two States, shall determine the tariff in according with these Regulations, where the licensee intending to distribute electricity and make payment therefor is under the Commission's jurisdiction.

3.3 The Commission shall determine the Aggregate Revenue Requirement and Tariff having regard to the principles, terms and conditions contained in Chapter-4 to Chapter-7 of these Regulations, as applicable.

3.4 Notwithstanding anything contained in these Regulations, the Commission shall adopt the tariff under section 63 of the Act, where such tariff has been determined through a transparent process of bidding in accordance with the guidelines issued by the Central Government to the extent they are consistent with the Act.

3.5 Any losses incurred by a generating company or a licensee and arising out of sale of electricity for which tariff is not determined under these regulations shall not be allowed to be compensated while determining the tariff or while truing-up is undertaken under these regulations.

3.6 The tariff determined or adopted for any generating station by CERC or the Commission under section 62(1), 63 and 64(5) of the Act will not be re-determined by the Commission while regulating the purchase and procurement process of the licensee under clause (b) of sub-section (1) of section 86 of the Act. However, the Commission may determine whether the licensee should enter into PPA or Commission should regulate the procurement process or procurement quantum as decided by the Commission.

CHAPTER – 2

GENERAL PRINCIPLES

4 Multi Year Tariff (MYT) Framework

4.1 The Commission shall determine the tariff for matters covered under regulation 3.1 of these Regulations, under a Multi-Year Tariff framework consisting of five years control period with effect from April 01, 2026.

4.2 The Multi-Year Tariff framework shall be based on the following elements, for computation of Aggregate Revenue Requirement (ARR) and Expected Revenue from Tariff (ERC) and Tariff for the Generating Companies, Transmission Licensees and Distribution Licensees.

(i) A Multi-Year Tariff Petition comprising the forecast of Aggregate Revenue Requirement, expected revenue from existing tariff, expected revenue gap or surplus, and proposed tariff for each year of the Control Period, shall be submitted by the Generating Company or Transmission Licensee or Distribution Licensee at least 120 days in advance of the effective date of the start of the control period:

Provided that the Distribution Licensee shall propose the category-wise Tariffs for each year of the Control Period:

Provided further that the performance parameters whose trajectories have been specified in these Regulations shall form the basis of projection for the Aggregate Revenue Requirement for the entire Control Period:

(ii) For Generating Company and Transmission Licensee:

a) The Commission shall determine the Aggregate Revenue Requirement and Tariff for Generating Company and Transmission Licensee for each year of the Control Period, at the start of the Control Period.

b) Petition for true-up of operational and financial performance of each ensuing year of the control period based on Audited Financial Statements vis-a-vis approved forecast of the year and revenue shortfall or surplus shall be submitted by the Generating Company and the Transmission Licensee by 30th of November of the succeeding financial year.

(iii) For Distribution Licensee:

a) The Commission shall determine the Aggregate Revenue Requirement for each year of the Control Period and tariff for first year of the control period, at the start of the Control Period. For subsequent years of the control period, the tariff for Distribution licensee shall be determined annually by the Commission, at the beginning of the respective financial year, duly incorporating truing-up of previous year(s):

Provided that any embeded generating station of a distribution licensee shall be treated similar to a generating station of a generating company for determination of tariff under these Regulations.

b) Petition for true-up of operational and financial performance of each ensuing year of the control period based on Audited Financial Statement vis-a-vis approved forecast of the year and revenue shortfall or surplus shall be submitted by the Distribution Licensee by 30th of November of the succeeding financial year.

c) Distribution Licensees shall submit petition for Mid-term Review of operational and financial performance vis-à-vis approved forecast for the first three years of the Control Period; and revised forecast of Aggregate Revenue Requirement, expected revenue from existing Tariff, expected revenue gap or surplus, as the case may be, for the fourth and fifth year of the control period by 30th November of the third year of the Control period.

Provided that the operational and financial performance for the third year shall be based on actuals of first six months and reasonable estimates for balance six months:

Provided further that Distribution Licensee in its petition for Mid-term Review may propose revised category-wise tariffs for the fourth and fifth year of the control period.

d) The Commission shall determine the revised Aggregate Revenue Requirement for Distribution Licensee for the fourth and fifth year of the Control Period based on the Mid-term Review. The revised ARR shall form the basis of annual tariff determination of the Distribution Licensee for fourth and fifth years of the Control Period.

(iv) In annual true-up the Commission shall undertake comparison of expenses and revenue based on Audited Financial Statements vis-à-vis the approved forecast for the respective year and categorization of variation in performance as those caused by factors within the control of the Petitioner (controllable factors) and those caused by factors beyond its control (uncontrollable factors).

(v) The mechanism for pass-through of approved gains or losses on account of uncontrollable factors shall be in accordance with Regulation 10 of these regulations.

(vi) The mechanism for sharing of approved gains or losses arising out of controllable factors shall be in accordance with Regulation 11 of these regulations.

5 Multi Year Tariff Petition

5.1 The Multi-Year Tariff Petition shall include a forecast of Aggregate Revenue Requirement and expected revenue from Tariff for each year of the Control Period in the manner and formats as specified in these Regulations.

5.2 The forecast of Aggregate Revenue Requirement may be based on assumptions relating to the behavior of individual variables during the Control Period, including category-wise sales and demand projections, power procurement plan, capital investment plan, financing plan and physical targets, in accordance with guidelines and formats as specified under these Regulations.

5.3 Generating Company, Transmission Licensee and Distribution Licensee shall prepare a five (05) year Fuel Utilization Plan, Capital Investment Plan and Power Purchase Plan, as applicable, following the methodology and principles specified in these regulations.

5.4 The capital investment plan shall show, separately, on-going projects that will spill over into the Control Period, and new projects (along with justification) that will commence in the Control Period but may be completed within or beyond it, for which relevant technical and commercial details shall be provided by the petitioner as specified under these regulations. All intra-state transmission projects shall be in consistent with the approved State Transmission Plan as per the Modalities of Tariff Regulations.

5.5 The Distribution Licensees shall project the realistic power purchase requirement, taking into consideration, the Resource Adequacy Guidelines specified in Schedule -2 of these regulations or any subsequent Guidelines issued by the Central Electricity Authority (CEA), the Long-term Discom Resource Adequacy Plan (LT-DRAP) vetted by the Central Electricity Authority, Merit Order Despatch principles of all Generating Stations considered for power purchase, quantum of Renewable Purchase Obligation (RPO) under the RE Regulations and the target set, if any, for Energy Efficiency (EE) and Demand Side Management (DSM) schemes:

Provided that at the time of filing of the MYT Petition, in case the Long-term Discom Resource Adequacy Plan (LT-DRAP), as vetted by the Central Electricity Authority (CEA) is not available, the Distribution Licensee shall submit its plan based on the Guidelines specified in Schedule-2 of these Regulations.

5.6 The forecast of expected revenue from Tariff and charges shall be based on the following:

a) In the case of a Generating Company, estimates of quantum of electricity to be generated by each Unit/Station for each year of the Control Period;

b) In the case of a Transmission Licensee, estimate of Aggregate Revenue Requirement or estimates of transmission capacity allocated to Transmission System Users, as appropriate, for each year of the Control Period;

c) In the case of a Distribution Licensee, estimates of quantum of electricity to be supplied to consumers and wheeled on behalf of Distribution System Users for each year of the Control Period:

Provided that the Distribution Licensee shall submit relevant details of category-wise sales separately for each

Distribution Franchisee area, including the Input Energy and the Input Rate;

d) Prevailing Tariff as on the date of filing of the Petition

5.7 Based on the forecast of Aggregate Revenue Requirement and expected revenue from Tariff and charges, Generating Company, or Transmission Licensee, or Distribution Licensee or SLDC shall submit the proposed Tariff, category-wise, as applicable, for each year of the Control Period, that would meet the gap, if any, in the Aggregate Revenue Requirement, including unrecovered revenue gaps of previous years to the extent proposed to be recovered.

5.8 Full details supporting the forecast shall be provided, including but not limited to details of past performance, proposed initiatives for achieving efficiency or productivity gains, technical studies, contractual arrangements and secondary research, to enable the Commission to assess the reasonableness of the forecast. All the past expenditures shall be based on the actual audited figures. An indicative list of documents to be submitted along with the petition is as below:

(i) The elements of fixed cost, fuel cost and power purchase cost estimated for the base year, and the actuals of the previous years in complete details, together with the projection for each item for ensuing years of the control period in the forms specified in Annexures-VI to IX, as applicable.

(ii) Detailed scheme/ project-wise Capital investment plan with capitalization schedule covering each year of the control period in line with Schedule-3;

(iii) Plans to contain and reduce the losses in generation, transmission and distribution both short-term and long-term. Where any energy audit has been conducted by any accredited energy auditor or any statutory bodies, broad details and results thereof along with the recommendations of the energy auditors may be submitted. The method and system of determining the losses and its bifurcation between technical losses and other than technical losses be suitably explained in detail.

(iv) Copies of Audited Financial Statements of last five years along with Auditor's Report and replies of the management;

(v) Copies of Cost Audit Reports of last five years;

(vi) ERC at the existing tariff including non-tariff income in the specified formats;

(vii) Proposed tariff structure or sale price of each of the ensuing years applicable for consumers or any licensee purchasing power from the applicant along with any proposal on terms & conditions of tariff. The rationale of tariff revision proposal and Category and sub-category wise details of consumers along with seasonal energy consumption and time- strata wise energy consumption for TOD system for each sub-category as applicable shall also be submitted;

(viii) A statement giving full details of subsidies received and receivable, if any, the consumers to whom it is directed and the way in which such subsidy is proposed to be reflected in the proposed tariffs applicable to these consumers;

(ix) Public notice containing the gist of the Tariff Application as specified in Annexure – V for publication;

(x) In case of differences between the amounts appearing in the audited financial statements and amounts appearing in the application for determination of tariff under any head, due to adjustments, for any reason whatsoever a reconciliation statement is to be furnished;

(xi) Distribution licensee shall submit its Resource Adequacy Plan;

(xii) Transmission licensee shall submit a copy of the State Transmission Plan approved in terms of the Modalities of Tariff Regulations;

(xiii) Any other matter considered appropriate.

5.9 The tariff shall be cost reflective and there shall not be any gap between approved Annual Revenue Requirement and estimated annual revenue from approved tariff except under natural calamity conditions:

Provided that such gap, created if any, shall not be more than three percent of the approved Annual Revenue Requirement.

6 Specific trajectory for certain variables:

The Commission, while approving the Multi-Year Tariff Petition, may stipulate a trajectory for certain variables, including but not limited to transmission losses, distribution losses, Reliability Indices, System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Aggregate Technical and Commercial Losses (AT&C Loss) and collection efficiency.

7 Mid-Term Review Petition by Distribution Licensee:

7.1 Petition shall include information in the forms specified in the Annexure, as applicable, together with the Accounting Statements, extracts of books of account and such other details, including Cost Audit Reports or extracts thereof, as it may require assessing the reasons for and extent of any difference in operational and financial performance from the approved forecast of Aggregate Revenue Requirement and expected revenue from Tariff and charges.

7.2 The scope of the Mid-term Review shall be a comparison of the actual operational and financial performance vis-à-vis the approved forecast for the first three years of the Control Period; and revised forecast of Aggregate Revenue Requirement, expected revenue from existing Tariff, expected revenue gap, and proposed category-wise Tariffs for the fourth and fifth year of the Control Period:

Provided that as part of the Mid-term Review, the Commission may inter-alia modify the category-wise sales, power purchase expenses, capitalization schedule and its impact in fixed costs, principles/basis of tariff categorisation, applicability of charges, Wheeling Charges, and category-wise Tariff, as considered appropriate based on the data made available for the first three years of the Control Period:

Provided further that necessary justification for the modifications made in the Mid-term Review shall be elaborated in the Mid-term

Review Order:

Provided also that if some expenses were allowed in the MYT order on provisional basis or was withheld due to any reason, the same may be allowed during Mid-term review subject to submission of adequate documents / clarification / compliance by the distribution licensee.

7.3 Upon completion of the Mid-term Review under regulation 7.2, the Commission shall attribute any variations or expected variations in performance, for variables specified under regulation 9, to factors within the control of the Petitioner (controllable factors) or to factors beyond its control (uncontrollable factors):

Provided that any variations or expected variations in performance, for variables other than those specified under Regulation 9.1, shall not ordinarily be reviewed by the Commission during the Control Period and shall be attributed entirely to controllable factors:

Provided further that, where the petitioner believes, for any variable not specified under Regulation 9.1, that there is a material variation or expected variation in performance for any year on account of uncontrollable factors, it may apply to the Commission for inclusion of such variable.

7.4 Upon completion of the Mid-term Review, the Commission shall pass an order recording:

(a) the approved modifications to the Aggregate Revenue Requirement for the remainder of the Control Period;

(b) the tariff of fourth year of the control period considering the modified Aggregate Revenue Requirement and duly incorporating the truing-up of previous year(s).

8 Truing-up petition

8.1 True-up petition shall include information regarding cost of assets capitalized, elements of fixed cost, fuel cost and power purchase cost of the respective year vis-à-vis the amount admitted in the Tariff Order, in the forms specified in the Annexures VI to X, as applicable, together with the Accounting Statements, extracts of books of account and such other details, including Cost Audit

Reports or extracts thereof for the respective year, as it may require assessing the reasons for and extent of any difference in operational and financial performance from the approved Aggregate Revenue Requirement.

8.2 True-up petition shall be submitted within the specified timeline. All the figures claimed in the true up petition shall be as per the Audited Financial Statements of the petitioner. In case of any figure varies from the Audited Financial Statements, due to any adjustment / reallocation, the petitioner has to submit reconciliation statement in support of their claim.

8.3 The scope of truing up shall be a comparison of the performance of the Generating Company, Transmission Licensee, Distribution Licensee and SLDC with the approved forecast of Aggregate Revenue Requirement and expected revenue from tariff and charges and shall comprise of the following:

b) admitting the capital cost of assets put to use during the year following the provisions of these regulations, subject to prudence check;

c) a comparison of the audited performance for the previous year with the approved forecast for that year, subject to the prudence check in respect of controllable and uncontrollable factors specified under regulation 9;

d) review of compliance with directives issued by the Commission from time to time;

e) other relevant details, if any.

8.4 In case where a specific principle of calculation exists for determination of any element of ARR at tariff determination stage under these regulations but nothing has been mentioned for truing up under these regulations, then such principle will also be applicable during truing up. Moreover during truing up exercise under these regulations for different data/ information including those pertaining to generating stations, generating companies and licensees, the Commission may, at its discretion, rely on and make use of any of the documents published orissued or supplied by Government of India, Central Electricity Authority, Government of West Bengal, different State Government and different statutory bodies formed under the Electricity Act, 2003 or any other statute of the country. In case of any discrepancies, or contradictions or inconsistencies in data and information contained in different documents as mentioned above including the information/data submitted by the licensee or the generating companies, the Commission, at its discretion, shall accept those data that will be found by the Commission to be rational or/and reasonable.

8.5 Upon completion of the Truing-up, the Commission shall pass an order recording.

(c) the approved aggregate gain or loss to the Distribution Licensee on account of controllable factors for and the amount of such gains or such losses that may be shared in accordance with Regulation 11;

(d) the approved aggregate gain or loss to the Distribution on account of uncontrollable factors, and the amount of such gains or such losses that were not recovered during the respective years and which may be shared in accordance with Regulation 10;

(e) the amount and the manner of recovery of admitted Revenue Gap or Revenue Surplus, as the case may be.

8.6 Carrying/ holding cost shall be allowed on the amount of Revenue Gap or Revenue Surplus, as determined in true-up order, for the period from the middle of the financial year in which such revenue gap / surplus had occurred upto the middle of the financial year in which the recovery has been allowed, calculated with simple interest at a rate equal to the bank rate:

Provided that, carrying cost/ holding cost shall be allowed on the net entitlement after sharing of efficiency gain and losses as approved after true-up:

Provided that, where recovery for revenue gap/surplus has been spread over number of years the carrying cost shall be computed for each year considering the opening and closing balance of revenue gap/surplus in the financial year.

9 Controllable and Uncontrollable Factors:

9.1 The “uncontrollable factors” shall comprise of the following factors which were beyond the control of, and could not be mitigated by the petitioner, as determined by the Commission:

(a) Force Majeure events;

(b) Change in law, judicial pronouncement, and orders of the Central Government, the State Government or the Commission;

(c) Taxes, Duties and statutory levies;

(d) Variation in sales in terms of quantity as well as consumer mix;

(e) Variation in fuel cost of generating station on account of variation in fuel mix and price of primary and/or secondary fuel;

(f) Variation in rail and / or ocean freight rates for fuel transportation of generating station;

(g) Variation in the cost of power purchase from approved sources due to variation in the rate of power purchase, subject to clauses in the power purchase agreement or arrangement approved by the Commission;

(h) Variation in Transmission charge to the extent of admitted power purchase;

(i) Variations in system operation charges viz. ERPC charge, ERLDC charge, SLDC charge;

(j) Variation in interest rate in long-term loans;

(k) Delay in Statutory Clearance and land acquisition; and

(l) Variation in Employee cost due to revision of pay & wages, effect of Pay Commission, etc.

9.2 Variations or expected variations in the performance of the Petitioner, which may be attributed by the Commission to controllable factors include, but are not limited to the following:

(i) Variation in technical and commercial losses;

(ii) Variation in operational norms;

(iii) Variation in amount of interest on working capital;

(iv) Variation in Operation & Maintenance expenses;

(v) Variation in Coal transit losses;

(vi) Variations in capitalisation on account of time and/or cost overruns/ efficiencies in the implementation of a capital expenditure project not attributable to an approved change in scope of such project, change in statutory levies or force majeure events.

10 Mechanism of pass-through of gains and losses on account of uncontrollable factors:

10.1 The approved gain or loss to the Generating Company or Licensee on account of uncontrollable factors, other than those covered under regulation 10.2 and 10.3 of these Regulations, shall be passed through, subject to prudence check during annual truing-up.

10.2 The aggregate gain or loss to a Generating Station of a Generating Company or licensee on account of variation in cost of fuel from the sources considered in the Tariff Order, including blending ratio of coal procured from different sources, shall be passed through as an adjustment in its Energy Charges on a monthly basis, as specified in Regulation 60 of these regulations.

10.3 The aggregate gain or loss to a Distribution Licensee on account of variation in cost of fuel, power purchase, sale to the consumers, Inter-State Transmission Charges and Intra-State Transmission Charges covered under Regulation 9.1, shall be passed through Fuel and Power Purchase Adjustment Surcharge (FPPAS), as an adjustment in its Tariff on a monthly basis, as specified in Schedule – 4 of these regulations:

Provided that in case the Distribution Licensee fails to compute and charge FPPAS within the timeline stipulated in these Regulations, except in case of any Force Majeure, its right for recovery of such cost shall be forfeited and Distribution Licensee shall not allow to recover such cost in True-up. However, variations on account of arrear / adjustments of power purchase cost not available during time of computation, if any, may be allowed to be recovered during true-up:

Provided further that in case FPPAS computed for any month is negative i.e. saving in expenses, then such saving shall be deposited in 'FPPAS Stabilisation Fund' to be maintained by the Distribution Licensee. Amount accrued along with holding cost in such Fund shall be used for offsetting positive FPPAS i.e. increased expenses of subsequent month(s), before levying it to the consumers.

11 Mechanism of sharing of gains or losses on account of controllable factors:

11.1 The approved aggregate gain to the Generating Company or Transmission Licensee or Distribution Licensee on account of controllable factors shall be dealt with in the following manner:

(a) One-third of the amount of such gain shall be passed on as a rebate in ARR /Tariff over such period as may be stipulated in the order by the Commission; and

(b) The balance amount of such gain shall be retained by the Generating Company or Transmission Licensee or Distribution Licensee, as the case may be.

11.2 The approved aggregate loss to the Generating Company or Transmission Licensee or Distribution Licensee on account of controllable factors shall be dealt with in the following manner:

(a) One-third of the amount of such loss shall be recovered as an additional charge in ARR/ Tariff over such period as may be stipulated in the order by the Commission; and

(b) The balance amount of such loss shall be absorbed by the Generating Company or Transmission Licensee or Distribution Licensee, as the case may be.

12 Operating Norms and Standard of Operating Performance:

12.1 The operating norms of different operational parameters pertaining to the years 2026 - 27 to 2030 - 31, on the basis of which the annual revenue requirement of any generating station or licensee will be determined, have been laid down in Schedule-5 of these Regulations. For subsequent years the Commission shall notify the norms through suitable amendment of schedule-5, as and when required:

Provided further that, in case of any Renovation & Modernization or Life Extension Programme of any existing generating station, the operating norms under Schedule -5 will be modified on the basis of submitted document(s) at the stage of investment approval.

12.2 The norms of operation specified under these Regulations are the ceiling norms and this shall not preclude Generating Company or Transmission Licensee or Distribution Licensee, as the case may be, and beneficiaries from accepting improved norms of operation as determined by the Commission and such improved norms shall be applicable for determination of tariff.

12.3 Any gain or loss on account of variation in actual performance of operating parameters of a generating station or licensee with respect to the norms admitted in the tariff order shall be shared with the beneficiary in terms of regulations 11.1 and 11.2 of these Regulations.

13 Accounts of the Generating Company, Transmission Licensee and Distribution Licensee:

The Generating Company, Transmission Licensee and Distribution Licensee shall prepare their financial statements in such a manner that all expenditure and income on different heads are mentioned distinctly and separately with necessary notes and description or additional schedule or auditor's certificate from the same auditor of the financial statements so that the Commission can take a proper view on each such head while determining the tariff and truing-up process:

Provided that wherever such expenditure and income are not adequately reflected in the financial statements through distinctly separate notes and description or additional schedule or auditor's certificate from the same auditor of the financial statements, as for example, if any expenditure under any head entitled 'others' or 'miscellaneous' or any other terminology which is non-specific, such expenditure may be disallowed by the Commission while determining the ARR:

Provided further that Generating Companies, Transmission Licensees and Distribution Licensees shall provide reconciliation statement showing the accounting statement under Indian Accounting standard (Ind AS) and Generally Accounting Accepted Principles (GAAP) as per financial statement and regulatory formats.

Provided further that the entity to which Ind AS do not apply and is governed by separate accounting rule by virtue of statute, the said entity shall continue to present its accounting statements under the statute it is governed.

Provided also that once the Commission notifies the Regulations for submission of Regulatory Accounts, the petitions for tariff determination and truing-up shall be based on the Regulatory Accounts.

14 Invitation of Suggestions and Objections or hearing

14.1 Notwithstanding anything to the contrary contained elsewhere in these regulations or any other regulations of the Commission, the Commission will undertake hearing or invite suggestions and objections in a manner and at astage which is only specifically provided in these regulations with following provisions:

i) Wherever there is invitation of suggestion and objection under these regulations it shall mean that such suggestion and objection shall always be submitted in written form only.

ii) Whenever suggestions and objections are required to be invited underthese regulations it shall be through advertisement in at least four (04) daily newspapers, at least one in Bengali language and one in English language, having wide circulation in the relevant area and also upload in its website in a manner as specified in these regulations for any purpose. Petitioner is also required to upload the soft copy in its internet website, in text-searchable pdf format or in downloadable spreadsheet format, as the case may be, and showing detailed computations, the petition filed before the Commission along with all regulatory filings, information, particulars and documents in the manner stipulated by the Commission:

Provided that the web link to the complete petition, including its formats and any additional information, shall be easily accessible, archived for downloading and be prominently displayed on the Petitioner's internet website:

Provided also that the Petitioner may be exempted by the Commission from providing any such information, particulars or documents as are confidential in nature.

Explanation – For the purpose of this clause, the term "downloadable spreadsheet format" shall mean one (or multiple, linked) spreadsheet software files containing all assumptions, formulae, calculations, software macros and outputs forming the basis of the petition.

iii) Hearing wherever provided in these regulations shall always be supported by a written submission which shall be compatible with the oral submission made during hearing. The issue(s) raised in the written submission of any hearing will only be considered as the content of hearing in the proceeding by the Commission.

15 Mitigation of Regulatory Uncertainty and Risk:

15.1 In order to remove any uncertainty in electricity business any Generating Company or Transmission Licensee or Distribution Licensee may submit any application to the Commission for getting 'in principle' clearance on any issue and/or for incurring any expenditure for which there is no specific approval mechanism mentioned under these regulations and have an impact on the tariff of the licensee or generating company prospectively:

Provided that in issuing such 'in principle' clearance, the Commission shall follow such procedure as is deemed necessary.

15.2 Notwithstanding anything to the contrary contained anywhere else in these regulations, if any activity of any Generating Company or Transmission Licensee or Distribution Licensee which needs governance under any regulation is found to have started prior to coming into force of such regulation, then in such case the

Generating Company or Transmission Licensee or Distribution Licensee, as the case may be, shall bring to the notice of the Commission such fact and the Commission may dispose of such matter in such a way so that the it does not face any loss due to any reason(s) that was needed to be addressed before coming into force of such regulation. However, where any prospective measure can meet the need of such regulation, the Commission may give appropriate direction if deemed necessary.

CHAPTER – 3

PROCEDURE FOR DETERMINATION OF TARIFF

16 Determination of Tariff:

16.1 The proceedings for determination of Tariff shall be undertaken by the Commission in accordance with the Conduct of Business Regulations, as amended time to time.

16.2 Notwithstanding anything contained in these Regulations, the Commission shall have the authority, either *suo motu* or on a Petition filed by the Generating Company or Licensee to determine its Tariff including terms and conditions thereof.

16.3 Notwithstanding anything contained in these Regulations, the Commission shall adopt the tariff, if such tariff has been determined through a transparent process of bidding in accordance with the guidelines issued by the Central Government:

Provided that the Applicant shall provide such information as the Commission may require for satisfying itself that the guidelines issued by the Central Government have been duly followed

17 Determination of Generation Tariff

17.1 The tariff for supply of electricity to a distribution licensee by a generating company from conventional sources of generation including pumped storage plants and hydro-generating station above 25 MW of installed capacity shall be determined in accordance with Chapter – 5 of these regulations subject to following:

17.2 Existing Generating Stations:

17.2.1 Where the Commission has, at any time prior to the notification of these regulations, approved a power purchase agreement or arrangement between a generating company and a distribution licensee or has adopted the tariff contained therein for supply of electricity from an existing generating station then the tariff for supply of electricity by the generating company to the distribution licensee shall be in accordance with such power purchase agreement or arrangement for such period as may be so approved or adopted by the Commission.

17.2.2 Where, as at the date of notification of these regulations, the power purchase agreement or arrangement between a generating company and a distribution licensee for supply of electricity from an existing generating station has not been approved by the Commission or the tariff contained therein has not been adopted by the Commission or where there is no power purchase agreement or arrangement, then the supply of electricity by such generating company to such distribution licensee after the date of notification of these regulations shall be in accordance with a power purchase agreement approved by the Commission in accordance with Chapter-8 of these regulations:

Provided that the Petition for approval of such power purchase agreement or arrangement shall be filed by the Distribution Licensee with the Commission within three (03) months from the date of notification of these Regulations:

Provided that the supply of electricity shall be allowed to continue under the present agreement or arrangement, as the case may be, until such time as the Commission approves of such power purchase agreement and shall be discontinued forthwith if the Commission rejects, for reasons recorded in writing, such power purchase agreement.

17.3 New Generating Stations:

The tariff determination for the supply of electricity by a generating company to a distribution licensee from a new generating station within the state shall be in accordance with a power purchase agreement approved by the Commission and subject to prior approval of the investment amount of the Generating Company by the Commission:

17.4 Own Generating Stations

17.4.1 Where a distribution licensee also undertakes the business of generation ofelectricity, the transfer price at which electricity is supplied by the generation business of the distribution licensee to its distribution business shall be determined by the Commission in a similar manner as may be done for a generating station of a generating company:

Provided that the Commission shall have regard to the terms and conditions specified in Chapter-5 of these Regulations in determination of transfer price for such supply.

17.4.2 The Distribution Licensee shall maintain separate records for the Generation Business and shall maintain an Allocation Statement so as to enable the Commission to clearly identify the direct and indirect costs relating to such business and return on equity accruing to such business.

17.4.3 The Distribution Licensee shall submit, along with the separate application for determination of tariff for retail supply of electricity, the information required under Chapter-5 of these Regulations relating to the Generation Business.

18 Determination of tariff for transmission, wheeling and retail sale of electricity:

18.1 The Commission shall determine the Aggregate Revenue Requirement and Tariff for transmission, wheeling and retail sale of electricity based on a petition filed by the Transmission Licensee and Distribution Licensee, as the case may be, in accordance with the procedure contained in these regulations.

18.2 The Commission shall determine the tariff for:

(a) Transmission of electricity, in accordance with the terms and conditions contained in Chapter – 6 of these regulations;

(b) Wheeling and retail tariff of electricity, in accordance with the terms and conditions contained in Chapter – 7 of these regulations;

19 Filing Procedure:

19.1 Petition for determination of Multi Year Tariff, Mid-term Review and True-up shall be filed in such form and in such manner as specified under these Regulations. All petitions shall be filed within the timeline specified in these Regulations and shall accompanied by applicable fees as specified in the Fees Regulations.

19.2 The petitioner shall provide, as part of its petition before the Commission, full details of its computation of ARR, expected revenue from charges, rationale behind projections, reasons / justification for deviations in case of true-up and all other documents specified in these regulations:

Provided that the petition shall be accompanied where relevant, by a detailed tariff revision proposal showing category-wise tariff and how such revision would meet the gap, if any, in Aggregate Revenue Requirement for the respective year of the Control Period:

Provided further that the Commission may specify different formats for details to be mandatorily submitted by the Petitioner, from time to time, as it may reasonably require for assessing the Aggregate Revenue Requirement and for determining the tariff:

Provided further that in order to bring uniformity about use of paper and to ensure neatness and legibility of the submissions, the petition, additional information, replies and other documents to be filed to the Commission by the Petitioner shall be prepared and submitted on superior quality A4 size paper (29.7 cm x 21 cm) with printing on one side of the paper with Font size 12, in one and half line spacing, with sufficient margins on left & right and on top & bottom. Each page shall be serially numbered and numbering shall continue to next volume(s), if any. Petition shall contain an Index specifying the contain and page number:

Provided further that, the petitioner shall also submit soft copy of the petition in text-searchable pdf format and the filled-up Forms in downloadable linked spreadsheet format showing detailed computations before the Commission:

Provided also that the Commission, or the Secretary or any Officer designated for the purpose by the Commission, may conduct a Technical Validation session prior to the admission of the petition.

19.3 Petition made shall be supported by affidavit of the authorised person of the Company, acquainted with the facts stated in the petition. The affidavit shall be made in such format as specified in the Conduct of Business Regulations.

19.4 Petitioner shall submit a duly completed draft Public Notice, inviting suggestions /objection from stakeholders, for the

Commission's approval as per the stipulated template, along with its petition.

19.5 Upon receipt of a complete petition accompanied by requisite fees, all requisite information, particulars and documents in compliance with all the requirements specified in these Regulations, the application shall be deemed to be received and the Commission or the Secretary or the designated Officer, shall intimate to the petitioner, subject to the satisfactory completion the Technical Validation Session, that the petition is registered and ready for publication along with the approved notice:

19.6 The Petitioner shall, within five (05) days upon intimation from the Commission, publish the public notice as approved by the Commission in newspaper and upload in its website, in terms of clause (ii) of regulation 14 of these regulations. The stakeholders shall be given at least 21 days to submit their suggestions, comments and objections:

Provided that the Petitioner shall make available a hard copy of the complete Petition to any person, from its registered office and zonal/regional offices and at rates as may be stipulated by the Commission.

19.7 The Petitioner shall furnish to the Commission all such books and records (or certified true copies thereof), including the Accounting Statements, operational and cost data, as may be required by it for determination of Tariff and truing-up.

19.8 The Commission may, if it considers necessary, make or cause to be made available to any person such information as has been provided by the Petitioner to it, including abstracts of books and records (or certified true copies thereof) on such terms and conditions as may be specified in the Conduct of Business Regulations.

19.9 The Commission may direct Generating Company, Transmission Licensee, or Distribution Licensee to submit such performance-related data as it may stipulate, with the petitions to be filed under these Regulations.

19.10 The Petitioner shall within three (03) days from the date of publication of the notice as aforesaid submit to the Commission on affidavit the details of the notice published and shall also file copies of the newspapers wherein the notice has been published.

19.11 The suggestions and objections, if any, on the proposal for determination of tariff or true-up, may be filed before the Secretary of the Commission, by any person within twenty-one (21) days of publication of the notice, with a copy to the Petitioner.

19.12 The Petitioner shall file its replies on the suggestions and objections, if any, received in response to his Petition within fourteen (14) days before the Commission.

19.13 The Petitioner shall file its MYT Petition, Mid-Term Review petition and/or Truing-up petition, as may be applicable, by 30th November of the year in which it is required to be filed in accordance with these Regulations:

Provided that that if petition is not filed within the specified timelines, the Petitioner may be penalized by way of reduction in the rate of return on equity by 0.25% per month or part thereof without prejudice to any other fine or penalty to which it may be liable under Electricity Act, 2003 and other Regulations of the Commission:

Provided also that if petition is not filed within the specified timelines and/or data sought by the Commission for processing the petition is not submitted within the stipulated time, then the corresponding revenue loss and associated carrying cost due to consequential delay in issue of the Order, shall not be allowed to the Generating Company or Transmission Licensee or Distribution Licensees, as the case may be. However, in case of over-recovered amount during the true-up period and delayed filing of true-up petition along with requisite documents, the surplus amount with holding cost / interest shall be recovered in terms of regulation 8.6 of these Regulations along with surplus amount.

20 Tariff Order:

20.1 The Commission shall, within one hundred and twenty (120) days from the date of admition of a complete petition and after considering all suggestions and objections received from the public:

(a) issue a tariff order accepting the petition with such modifications or such conditions as may be specified in that order; or

(b) reject the Petition for reasons to be recorded in writing if such application is not in accordance with the provisions of the Act and the rules and Regulations made thereunder or the provisions of any other law for the time being in force:

Provided that a Petitioner shall be given a reasonable opportunity of being heard before rejecting its Petition.

20.2 The Commission shall also approve the perspective plan with appropriate modifications as may be considered necessary for the control period.

20.3 The Commission shall, within 7 (seven) days of making the tariff order, send a copy of the order to the state government, the authority, and the concerned applicant. The Commission shall also make available certified copies of order to any person on payment of a cost fixed by the Commission.

20.4 The applicant shall within the time specified in the tariff order of the Commission, publish the salient features of tariff or tariffs approved by the Commission in at least 4 (four) dailies of which at least 1 (one) will be in English, and 1 (one) in Bengali having wide circulation in the operational area of licensee and shall put up the approved tariff on its internet website:

Provided that where the applicant is a generating company, the publication shall be in such newspapers as are widely circulated in the area of supply of the distribution licensee to whom the electricity will be supplied in terms of the tariff order and shall also be put up on the internet website of such distribution licensee and the generating company concerned.

20.5 The tariff so published shall be in force from the date specified in the said order and shall, unless amended or revoked, continue to be in force for such period as may be specified in the said order.

20.6 If in any tariff order there is no express provision, or express direction in respect of any matter that has been covered by an express provision or direction in an earlier tariff order or as per condition of supply of licensee prior to coming into force of the Act or as per any order of Appropriate Government prior to coming into force of the Act, the latter shall be deemed to have a continuing effect, until such provision or direction is altered, modified or discontinued by fresh directions in a subsequent tariff order. However, such change shall be applicable prospectively from a date to be fixed by the Commission.

20.7 If in any tariff order there is no express provision, or express direction in respect of any matter that has been covered by an express provision of these regulations, then the provision of such regulation will be considered as part of the tariff order.

20.8 If any regulation of the principal Regulations is amended, then the existing tariff order will continue till the next tariff order is issued.

21 Adherence to Tariff Order

21.1 No Tariff or part of any Tariff may ordinarily be amended more frequently than once in a year, except in respect of any changes expressly permitted under FPPAS as specified in Regulation 10.3 of these regulations.

21.2 The tariff shall normally be revised from the prospective date unless there is a compelling reason to revise the same from the retrospective date in which case detailed justification will be given in writing by the Commission.

21.3 If any Generating Company, Transmission Licensee or Distribution licensee recovers a price or charge exceeding the tariff determined under section 62 of the Act and in accordance with these Regulations, the excess amount shall be refunded along with interest as determined by the Commission without prejudice to any other liability incurred by such Generating Company, Transmission Licensee or Distribution licensee:

Provided that such interest payable to any party shall not be allowed to be recovered through the Aggregate Revenue Requirement of the Generating Company or Transmission Licensee or Distribution Licensee:

Provided also that the Generating Company or Transmission Licensee or Distribution Licensee shall maintain separate details of such interest paid or payable by it and shall submit them to the Commission along with its Petition.

21.4 The Generating Company, Transmission Licensee and Distribution Licensee shall submit periodic returns as may be required by the Commission, containing operational and cost data to enable the Commission to monitor the implementation of its order.

22 Subsidy Mechanism

22.1 If the State Government requires the grant of any subsidy to any consumer or class of consumers in the tariff determined by the Commission, the State Government shall, notwithstanding any direction which may be given under section 108 of the Act, pay in advance by a suitable mechanism to be approved by the Commission or a separate account payee cheque / demand draft / banker's cheque/electronic fund transfer in favour of the licensee or such other person to implement the subsidy, the amount to compensate the Distribution Licensee/ person affected by the grant of subsidy, as a condition for the licensee or any other person concerned to implement the subsidy provided for by the State Government.

Provided that no such direction of the State Government shall be operative if the payment is not made in accordance with the provisions contained in this regulation, and the tariff fixed by the Commission shall be applicable.

22.2 Accounting of the subsidy payable under section 65 of the Act, shall be done by the Distribution Licensee, in accordance with the Standard Operating Procedures issued by the Central Government, in this regard.

22.3 Distribution Licensee shall submit to the Commission a quarterly report consisting of details w.r.t demands of subsidy raised by Distribution Licensee to the State Government during the relevant quarter based on the accounts of the energy consumed by the subsidised category and consumer category wise per unit subsidy declared by the State Government, the actual payment of subsidy in accordance with section 65 of the Act and the gap in subsidy due and paid as well as other relevant details, as may be specified by the Commission and / or Ministry of Power vide its Rules framed under the provisions of the Act.

23 Deviation from ceiling Tariff:

23.1 The tariff determined in accordance with these Regulations shall be a ceiling tariff, and the Generating Company or Transmission Licensee and their Beneficiaries may mutually agree to charge a lower tariff.

23.2 The Generating Company or Transmission Licensee may opt to charge a lower tariff for a period not exceeding the validity of these Regulations on agreeing to deviation from operational parameters, reduction in Operation and Maintenance expenses, reduced Return on Equity and incentive specified in these Regulations.

23.3 The deviation from the ceiling tariff determined by the Commission, shall come into effect from the date agreed to by the Generating Company or Transmission Licensee and the Beneficiaries.

23.4 The Generating Company and the Beneficiaries of a Generating Station or the Transmission Licensee and the Beneficiaries shall be required to intimate the Commission for charging lower tariff in accordance with Regulation 23.1 to 23.3 above. The details of the accounts and the tariff charged under Regulation 23.1 to 23.3 shall be submitted at the time of true up. The revenue loss on account of charging lower than approved tariff shall be borne entirely by the Generating Company or Transmission Licensee and the impact of such revenue loss shall not be passed on to the Beneficiaries, in any form.

24 Tariff in Multiple Licensee area:

24.1 The tariffs of any Distribution Licensee determined under these regulations for different categories of consumers are the maximum ceilings for supply of electricity at any agreed price to the consumers, only for those areas of supply of the licensee where multiple Distribution Licensees exist, subject to the condition that if for effecting of supply of electricity to any consumer at such lesser price than the above mentioned ceiling the Distribution Licensee incurs any loss, such loss shall not be allowed to be passed on to any other consumers or any other licensee of the Commission.

24.2 Alternatively, the incumbent Distribution Licensees shall have the option of filing separate petitions under these Regulations for an area in respect of which the Commission has issued multiple Distribution Licenses:

Provided that each such separate petition shall contain all necessary details of expenses, revenue, assets, liabilities, capitalisation, and category-wise tariff to enable the Commission to determine the Aggregate Revenue Requirement and tariff for each separate area for which it has been filed:

Provided further that such expenses, revenue, assets, liabilities, and capitalisation considered for each such area shall be excluded while submitting the petition for the remaining area of supply:

Provided also that Distribution Licensee shall submit the reconciliation statement for expenses, revenue, assets, liabilities, and capitalisation between the entity as a whole and each such separate area of supply for which Distribution Licensee has filed a separate petition.

CHAPTER – 4

FINANCIAL PRINCIPLES

25 Capital Cost

25.1 In case of existing projects, the capital cost admitted by the Commission prior to 01.04.2026 duly trued up by excluding liability, if any, as on 01.04.2026. and the additional capital expenditure projected to be incurred for the respective year of the Control Period, as may be admitted by the Commission, shall form the basis for determination of tariff.

25.2 The Capital Cost for a new project shall include:

a) expenditure incurred or projected to be incurred up to the date of commercial operation of the project or the date of put to use, as the case may be;

b) interest during construction, financing charges and incidental expenditure during construction as admitted by the Commission in accordance with these regulations after prudence check;

c) capitalised initial spares subject to the ceiling rates specified in these regulations;

d) expenditure incurred by the licensee on obtaining right of way, as admitted by the Commission;

e) expenditure on account of additional capitalisation as determined in accordance with Regulation 28 of these regulations;

f) any gains or losses on account of foreign exchange rate variation (FERV) pertaining to the loan amount availed up to the cut-off date, as admitted by the Commission after prudence check;

g) Capital expenditure on account of biomass handling equipment and facilities, for co-firing:

Provided that any gains or losses on account of foreign exchange rate variation pertaining to the loan amount availed up to the date of commercial operation shall be adjusted only against the debt component of the capital cost:

Provided further that the capital cost of the assets forming part of the Project but not put to use or not in use, shall be excluded from the capital cost:

Provided also that the Generating Company or Transmission Licensee or Distribution Licensee, as the case may be, shall submit documentary evidence in support of its claim of assets being put to use:

Provided also that the Commission may undertake a verification to check if the assets are put to use as submitted by the Generating Company or Transmission Licensee or Distribution Licensee, as the case may be, independent of the tariff determination process:

25.3 In case of existing or new hydro Generating Station, the Capital cost shall also include:

(a) cost of approved rehabilitation and resettlement (R&R) plan of the project in conformity with National R&R Policy and R&R package as approved;

(b) cost of developer's contribution towards local electrification mandated under different Central and/or State Government schemes; and

(c) for uninterrupted and timely development of Hydro projects, expenditure incurred towards developing local infrastructure in the vicinity of the power plant not exceeding Rs. 10 lakh/MW shall be considered as part of the Capital cost, and in case the same work is covered under budgetary support provided by the Central and/or State Government, the funding of such works shall be adjusted on receipt of such funds:

Provided that such funds shall be allowed only if the funds are spent through Indian Governmental Instrumentality;

25.4 For projects acquired through NCLT proceedings under the Insolvency and Bankruptcy Code, 2016, the following shall be considered while approving Capital Costs for the determination of tariff:

(a) For projects already under operation, historical GFA of the project acquired or the acquisition cost paid by the generating company, whichever is lower;

(b) For considering the historical GFA for the purpose of Sub-Clause (a) above, the same shall be the capital cost approved by the appropriate commission till the date of acquisition;

Provided that in the absence of any prior approved capital cost of an Appropriate Commission, the Commission shall consider the same on the basis of audited accounts subject to prudence check;

Provided further, that in case additional capital expenditure is required post acquisition of an already operational project, the same shall be considered under the provisions of regulation 28 of these regulations;

(c) In case any under construction project is acquired that has yet to achieve commercial operation, the acquisition cost or the actual audited cost incurred till the date of acquisition, whichever is lower, shall be considered and;

Provided that, any additional capital expenditure incurred post acquisition of such project up to the date of commercial operation of the project in line with the investment approval of the Board of Directors of the generating company or the transmission licensees shall also be considered on a case to case basis subject to prudence check.

Provided that post commercial operation, additional capital expenditure shall be allowed under the provisions of regulation -28 of these regulations.

25.5 Following shall be excluded from the capital cost of the existing and new projects:

a) The assets forming part of the project, but not put to use or not in use, as declared in the tariff petition;

b) De-capitalized assets after the date of commercial operation on account of replacement or removal on account of obsolescence or shifting from one project to another project:

c) In case of hydro generating stations, any expenditure incurred or committed to be incurred by a project developer for getting the project site allotted by the State Government by following a transparent process;

d) Proportionate cost of land of the existing project which is being used for generating power from renewable sources;

e) Any consumer contribution or grant received from the Central or State Government or any statutory body or authority for the execution of the project, which does not carry any liability of repayment;

f) Any asset funded through contribution to Unforeseen Exigency Reserves or Development Fund;

g) Any assets funded through proceeds of insurance claims; and

h) Any capitalisation done by mere book entries / presentation in the financial statements in order to comply with any statute / rules etc. and not in accordance with the Capital Expenditure approved under these regulations.

25.6 For all existing projects the Generating Company or Transmission Licensee or Distribution Licensee may claim for additional capitalization on account of undischarged liabilities, deferred works under original scope of work, to comply with requirement under change in law or direction of any court of law or statutory body, replacement of any asset, renovation & modernization, life extension programs, improvement of efficiency, etc. to the extent and in such manner as allowed under Regulation 28 of these regulations.

25.7 **In-principle Approval**: The Commission has specified the Guidelines for approval of Capital Investment Schemes as provided in Schedule - 3 of these regulations. The Generation Company or Transmission Licensee or Distribution Licensee, as the case may be, shall make a petition to the Commission for obtaining prior in-principle approval of the Commission for schemes involving major investments, known as DPR-schemes, as per criteria specified in the Guidelines. The petition shall accompany with applicable fees as per the Fees Regulations. The Commission after prudence check may accord in-principle approval of the Capital Investment Scheme or may reject such petition mentioning the reasons thereof:

Provided that no in-principle approval is required for non-DPR schemes or the schemes with 100% Government Grant:

Provided further that for any capital project partly funded through grant and where the balance fund through debt or equity equals to or above the criteria specified for DPR-scheme, then prior in-principle approval is to be obtained by the utility:

Provided further that the utility shall submit all details including DPRs and other approval documents, of Schemes funded through Central or State Grant or through Consumer Contribution or through Deposit works and/or Loan convertible to grant on fulfilment of specified conditions, to the Commission prior to the initiating execution of such Schemes:

Provided further that for emergency works, utility shall mandatorily intimate the Commission within 15 days from the start of the work and shall submit the DPR complete in all respects for post-facto approval of the Commission, if the capital investment falls within the limits specified for DPR-Schemes:

25.8 Generating Company or Transmission Licensee or Distribution Licensee shall submit quarterly status report for all approved DPR schemes in the manner and format specified by the Commission from time to time. In case the utility fails to award within one year from the date of in-principle approval accorded by the Commission, the approval shall be deemed cancelled.

25.9 **Final Capital Cost approval**: After completion of the projects, utility shall submit its claim for final capital cost approval along with its true-up petition for all completed projects in the form and manner specified in Schedule -3 of these regulations. The final capital cost approved by the Commission after prudence check following the principle and the guidelines specified in Schedule-3 of these regulations shall form the basis for determination of the Aggregate Revenue Requirement:

Provided also that in case of new generating station or extension of existing generating stations, petition for final project cost approval shall be submitted within three months from the cut-off date:

Provided that for projects where investment approval has been accorded by the Commission prior to 01.04.2026 under the repealed regulations, shall be construed as in-principle approval under these regulations:

Provided further that, for the projects where the timeline for submitting the final project cost as per the repealed regulation was on or before 31.03.2026, the Generating Company or Transmission Licensee or Distribution Licensee shall submit petition for approval of final capital cost of such projects under these regulations, within

6 months from the issuance of these regulations:

Provided further that for non-DPR projects details of actual capital cost shall be submitted along with true-up petition.

25.10 Actual capital expenditure as on COD for the original scope of work may be considered based on audited accounts of Generating Company or Transmission Licensee or Distribution Licensee, limited to original cost and subject to prudence check by the Commission:

Provided that any escalation in the capital cost for which sufficient justification is provided may be considered by the Commission subject to prudence check:

Provided that in case the actual capital cost is lower than the approved capital cost, then the actual capital cost will be considered for determination of tariff of Generating Company, Transmission Licensee and Distribution Licensee:

Provided further that, where any DPR-Scheme consists of number of identifiable capital works with specified target timelines mentioned during the in-principle approval, part capitalization under such DPR-scheme may be considered for such identifiable capital works upto 95% of the admitted cost. Balance amount shall be adjusted during final capital cost approval of the entire DPR-Scheme.

25.11 The Generating Company or Transmission Licensee or Distribution Licensee shall prepare Capital Investment Plan for the entire control period following the Guidelines specified in Scheulde-3, and submit it along with the Multi Year Tariff Petition or Mid-term Review Petition, as the case may be. The Capital Investment Plan shall highlight all approved DPR-Schemes, proposed DPR-Schemes yet to be approved and all non-DPR schemes proposed during the control period along with year-wise and scheme-wise capital expenditure and capitalization schedule. Capital Investment Plan shall also include the brief description, objective, funding principles, expected completion time and cost-benefit analysis of each DPR and non-DPR Schemes:

Provided that for all the capital projects falling under DPR-schemes completed prior to the base year and where final capital cost has been approved by the Commission, the approved final capital cost shall be considered for determination of ARR:

Provided further that, for the DPR schemes where in-principle approval has been accorded by the Commission, 95% of such approved amount shall be considered for determination of ARR:

Provided further that, the Commission may consider, an additional amount up to 20% of the total capital expenditure approved for that year, towards planned or unplanned capital expenditure for which DPR is yet to be approved by the Commission:

Provided further that cumulative amount of capitalisation against non-DPR schemes for any year shall not exceed 20% of the cumulative amount of capitalisation approved against DPR schemes for that Year or 0.5% of the GFA of the respective business of the petitioner, whichever is lower:

Provided further that, capitalisation under schemes funded through Central or State grant or through Consumer Contribution or through Deposit works shall not form part of the above-mentioned limit of the cumulative capitalisation:

Provided further that Generating Company or Transmission Licensee or Distribution Licensee, as the case may be, should ensure that expenses that would normally be classified as O&M expenses are not claimed under non-DPR schemes:

Provided further that Capital cost considered by the Commission in the MYT Orders shall not be termed as "In-principle approval" and the same shall be governed by the provisions of Schedule – 3 of these regulations.

25.12 Generating Company or Distribution Licensee shall provide a copy of the proposed Capital Investment Plan for Generation and/or Distribution Business, as the case may be, to the State Transmission Utility (STU) for carrying out planning for network augmentation/ strengthening at the time of filing of this plan with the Commission. The copy of approved capital investment plan shall also be sent to the STU, immediately after approval by the Commission

25.13 Generation Company or Transmission Licensee or Distribution Licensee, as the case may be, shall be required to ensure that the procurement of the assets have been undertaken in a competitive and transparent manner. Further, the assets so capitalized as a part of the approved capital investment plan under these regulations should necessarily be geo-tagged and properly recorded in Fixed Asset Register (FAR) for allowance of the capitalization of the same by the Commission:

Provided further that regarding the assets already capitalized as on April 01, 2026, Generation Company or Transmission Licensee or Distribution Licensee, as the case may be, shall prepare and submit to the Commission a time-bound plan to undertake the geo-tagging in phased manner, preferably within the Control Period, along with the MYT Petition:

Provided further that Generation Company or Transmission Licensee or Distribution Licensee, as the case may be, must provide access of the details of geotagging to the Commission for online monitoring.

26 Prudence Check of Capital Cost:

26.1 Capital cost admitted by the Commission after prudence check shall form the basis for determination of tariff.

26.2 Prudence check of capital cost shall include scrutiny of the reasonableness of the capital expenditure, financing plan including the choice and manner of funding, interest during construction, incidental expenditure during construction, use of efficient technology, cost over-run and time over-run, procurement of equipment and material in a competitive and transparent manner and such other matters as may be considered appropriate by the Commission:

Provided that, while carrying out the prudence check, the Commission shall also examine whether the Generating Company or Transmission Licensee or Distribution Licensee, as the case may be, has been prudent in its judgement and decisions in execution of the project.

26.3 Prudence check of capital cost may be carried out taking into consideration the benchmark norms specified/to be specified by the Commission from time to time:

Provided that in cases where benchmark norms have been specified, Generating Company or Transmission Licensee or Distribution Licensee shall submit the reasons for exceeding the capital cost from benchmark norms to the satisfaction of the Commission for allowing cost above benchmark norms:

Provided further that in cases where benchmark norms have not been specified, prudence check may include scrutiny of the capital cost in light of the capital cost of similar project based on past historical data, wherever available.

26.4 Generating Company or Transmission Licensee or Distribution Licensee, as the case may be, shall furnish the details of capital cost for execution of the existing and new projects as per formats specified by the Commission from time to time along with tariff petition for the purpose of creating a database of benchmark capital cost of various components.

26.5 The Commission may get the capital cost of any project vetted by an independent agency or an external expert. However, the same shall be considered as one of the guiding factors only and shall not be binding on the Commission.

26.6 Where the power purchase agreement or bulk power transmission agreement provides for a ceiling of capital cost, the capital cost to be considered shall not exceed such ceiling.

26.7 Capital cost of the assets related to unregulated business being transferred to regulated business shall be considered after deducting the amount of accumulated depreciation, computed till the period of asset utilization for unregulated business and/or for the period for which the assets remained unutilized, for the purpose of tariff determination, in the following instances:

a) The asset/s have been used for a period of time for unregulated business or the asset/s have become part of the asset base of the regulated business after lapse of time with respect to the COD of the asset;

b) If the asset has not been put to use for the regulated business after COD.

26.8 Revenue earned from sale of infirm power in excess of fuel cost prior to the COD as specified under Regulation 57 of these regulations, shall be adjusted against the Capital Cost.

26.9 Capital cost may include initial spares capitalised as a percentage of the Plant and Machinery cost up to cut-off date, subject to following ceiling norms:

a) Coal-based/lignite-fired thermal generating stations - 4.0 %

b) Gas Turbine/Combined Cycle thermal generating stations - 4.0 %

c) Hydro generating stations including pumped storage plant – 4.0%

d) Transmission and Distribution system:

(i) Transmission and Distribution Lines - 1.0 %

(ii) Transmission and Distribution Sub-station (Green Field)- 4.0 %

(iii) Transmission Sub-station (Brown Field) - 6.0 %

(iv) Series Compensation devices and HVDC Sub-station - 4.0 %

(v) Gas Insulated Sub-station (GIS) - 5.0 %

(vi) Communication System - 3.5 %

(vii) Static Synchronous Compensator - 6.0 %

(viii) Integrated mine – as per mining plan

Provided that, Plant and Machinery cost shall be considered as the original project cost excluding IDC, IEDC, Land Cost and Cost of Civil Works. The Generating Company or Transmission Licensee or Distribution Licensee, for the purpose of estimating Plant and Machinery Costs, shall submit the break-up of head-wise IDC and IEDC:

Provided further that, where the generating station has any transmission equipment forming part of the generation project, the ceiling norms for initial spares for such equipment shall be as per the ceiling norms specified for the transmission system under these regulations:

Provided also that, where the emission control system is installed, the norms of initial spares specified in this Regulation for coal or lignite based thermal generating stations, as the case may be, shall apply.

26.10 The indicative list of various categories of Schemes that shall not be allowed as Capital Investment Schemes (DPR as well as Non-DPR) for Generating Companies or Transmission Licensees or Distribution Licensees is as follows:

a) Any expenditure on acquiring the minor items or the assets including tools and tackles, furniture, air-conditioners, voltage stabilizers, refrigerators, coolers, computers, fans, washing machines, heat convectors, mattresses, carpets, etc., bought after the cut-off date shall not be considered for additional capitalization for determination of tariff;

b) Replacement/repairing of individual items such as Current Transformer (CT), Potential Transformer (PT), Lightning Arrestor (LA), Circuit Breaker (CB), Distribution Box, Cables, LT switchgears, protection system, Insulators and Hardware after failure;

c) O&M/overhauling of the equipment such as CB, Transformers, ICTs, Coal Mills, Boiler, Compressor, Generator, Alternator, Coal Handling Plant, Ash Handling Plant, etc.;

d) Replacement of small part of the entire system such as Relays of Sub-stations, control, protection and communication panels of Sub-station equipment, replacement of the panel meters, reprogramming of meters;

e) Replacement of the members of the Transmission Towers, increasing height of the towers, replacement of few towers, replacement of few spans of the conductor of Transmission lines, re-earthing of the Sub-stations and Towers, Strengthening of Towers/Poles, replacement of motors, gearbox, Stators, Rotors, Coal Mill parts, Security System (including digital), replacement of protection and control system, water supply system, replacement of ancillary system/Street Lights, etc., where the cost of individual replacement is less than Rs. 20 Lakh;

f) **P**remature Replacement of Air Insulated Substation (AIS) with Gas Insulated Substation (GIS)/Underground Cables/Transmission Lines/other equipment before completion of Useful Life, and even after completion of Useful Life in cases where replacement is not justified based on the diagnostic test reports/Study report;

g) Foundation strengthening of the Towers/Poles, substation equipment, internal civil work, repair and maintenance of office/residential quarters/guest house and office building, Metal spreading in yard, furniture, Repair and maintenance of control rooms, Compound wall for the Sub-stations and empty land, street light replacement, R&M of existing roads and buildings, etc.;

h) Procurement of maintenance spares, Annual Maintenance Contract (AMC);

i) Beautification projects, development of Garden, advertisement expenses;

j) Distribution/Generation scope of work included in Transmission DPR, Transmission Scope included in Generation DPR, etc.;

k) DPR for only land without any project proposal;

l) Premature replacement of the equipment, cables, rerouting of cables/lines for freeing the space for other project/infrastructure activities of Utility;

m) Work required for restoration of supply post occurrence such as Tower collapse, conductor snapping, shifting of the Tower/poles on consumer request;

n) Clubbing of scope of work of O&M nature at different plants, substations, lines;

o) Opex Schemes as provided in the Regulations;

p) Expenditure that should be taken up under O&M expenses;

q) Transmission Schemes that are not included in the STU rolling Plan prepared under Modalities for Tariff Regulations, except Non-DPR Schemes;

r) Schemes that have not obtained the Commission's in-principle approval, unless they are exempted.

26.11 The impact of revaluation of assets shall be permitted during the Control Period, provided it does not result in increase in tariff of Generating Company, Transmission Licensee or Distribution Licensee:

Provided that any benefit from such revaluation shall be passed on to persons sharing the capacity charge in case of a Generating Company, or to long-term Intra-State open access customers of Transmission Licensee, or retail supply consumers in case of Distribution Licensees, at the time of Multi-Year Tariff determination, or Mid-term Review or Truing up, as the case may be.

26.12 Any expenditure on replacement, renovation and modernization or extension of life of old fixed assets, as applicable to Generating

Company, Transmission Licensee or Distribution Licensee, shall be considered after writing off the net value of such replaced assets from the original capital cost and will be calculated as follows:

Net Value of Replaced Assets = OCRA – AD –G/CC;

Where;

OCRA: Original Capital Cost of Replaced Assets;

AD: Accumulated depreciation pertaining to the Replaced Assets;

G/CC: Total Grants or Consumer Contribution pertaining to the Replaced Assets:

Provided that, in case the original capital cost of the replaced asset is not available for any reason, it shall be considered by the Commission on a case to case basis:

Provided further that the amount of insurance proceeds received, if any, towards damage to any asset requiring its replacement shall be first adjusted towards outstanding actual or normative loan; and the balance amount, if any, shall be utilised to reduce the capital cost of such replaced asset, and any further balance amount shall be considered as Non-Tariff Income.

Explanation – For the purpose of this Regulation, the term 'renovation and modernisation' shall have the same meaning as in clause 138 of the Income-Tax Act, 2025.

26.13 In case of de-capitalisation of assets of a Generating Company or Transmission Licensee or Distribution Licensee, as the case may be, the original cost of such asset as on the date of decapitalization shall be deducted from the value of gross fixed asset and corresponding loan as well as equity shall be deducted from outstanding loan and the equity respectively in the year such de-capitalisation takes place with corresponding adjustments in cumulative depreciation and cumulative repayment of loan, duly taking into consideration the year in which it was capitalised.

Provided that the de-capitalization of the old asset for the purpose of tariff, is effected from the very same year in which the capitalization of the new asset is allowed, irrespective of its actual de-capitalization in the books of accounts of the Generating Company, Transmission Licensee or Distribution Licensee, as the case may be.

Provided that in case the original cost of the de-capitalised asset is not available, the Commission shall consider the same by de-escalating the gross value of the new asset @ 5% per annum until the year of capitalization of the old asset.

27 Interest During Construction (IDC) and Incidental Expenditure during Construction (IEDC)

27.1 Interest during construction (IDC) shall be computed considering the actual loan and normative loan after taking into account the prudent phasing of funds up to actual COD:

Provided that IDC on a normative loan corresponding to excess equity over 30% of funds deployed shall be allowed only in cases where the actual infusion of equity on a pari-passu basis is more than 30% of total funds deployed and shall be computed on a quarterly basis:

Provided further that in case IDC on normative loan is to be allowed prior to infusion of actual loan, rate of interest for computing such IDC shall be equal to 1-year SBI MCLR as prevailing on 1st April of the respective year:

Provided also that IDC on normative loan, post infusion of actual loan shall be computed based on weighted average rate of interest of actual loan(s) for that respective quarter.

27.2 Incidental expenditure during construction (IEDC) shall be computed from the zero date, taking into account pre-operative expenses up to actual COD:

Provided that any revenue earned during the construction period up to actual COD on account of interest on deposits or advances or any other receipts shall be taken into account for reduction in incidental expenditure during construction.

27.3 In case of additional costs on account of IDC and IEDC due to delay in achieving the COD, the generating company for a specific generating station or for an integrated mine or the transmission licensee or distribution licensee, as the case may be, shall be required to furnish detailed justifications with supporting documents for such delay, including prudent phasing of funds in the case of IDC and details of IEDC during the period of delay and liquidated damages recovered or recoverable corresponding to the delay.

27.4 If the delay in achieving the COD is not attributable to the generating company or transmission licensee or distribution licensee, such additional IDC and IEDC may be allowed after a prudence check, and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be adjusted to the capital cost of the generating station or the transmission system, as the case may be.

27.5 If the delay in achieving the COD is attributable either in entirety or in part to the generating company or transmission licensee or distribution licensee or its contractor or supplier or agency, in such cases, IDC and IEDC due to such delay may be disallowed after a prudence check, either in entirety or on a pro-rata basis corresponding to the period of delay not condoned vis-à-vis total implementation period, and the liquidated damages, or other damages, if any, recovered from the contractor or supplier or agency shall be retained by the generating company or transmission licensee or distribution licensee, in the same proportion of delay not condoned vis-à-vis total implementation period.

[Note: For e.g.: In case a project was scheduled to be completed in 48 months and is actually completed in 60 months. Out of 12 months of time overrun, if only 6 months of time overrun is condoned, the allowable IDC and IEDC shall be computed by considering the total IDC and IEDC incurred for 60 months and allowed in the proportion of 54 months over 60 months period.]

Provided that in cases where delay in achieving COD is beyond six months from SCOD on account of delay in obtaining approval of any of the following activities namely, i) forest clearance, ii) NHAI clearance, or iii) Railways permission, a time overrun maximum up to 95% shall be allowed after prudence check.

27.6 For the purpose of Regulations 27.4 and 27.5 of these regulations, IDC on actual loan and normative loan shall be considered in accordance with the normative debt-equity ratio specified under Regulation 30 of these regulations.

27.7 The following shall be considered as controllable and uncontrollable factors for deciding time overrun, cost escalation, IDC and IEDC of the new projects:

(i) The "controllable factors" shall include but shall not be limited to the following:

(a) Efficiency in the implementation of the new projects not involving an approved change in scope of such new projects or change in statutory levies or change in law or force majeure events; and

(b) Delay in execution of the new projects on account of contractor or supplier or agency of the generating company or transmission licensee.

(ii) The "uncontrollable factors" shall include but shall not be limited to the following:

(a) Force Majeure events;

(b) Change in Law; and

(c) Land acquisition except where the delay is attributable to the generating company or transmission licensee or distribution licensee.

28 Additional Capitalisation

28.1 Additional Capitalisation within the original scope and up to the cut-off date:

Capital expenditure, actually incurred or projected to be incurred, in respect of new project or an existing project, on the following counts within the original scope of work, after the date of commercial operation and up to the cut-off date may be admitted by the Commission, subject to prudence check:

(i) Undischarged liabilities recognized to be payable at a future date;

(ii) Works deferred for execution;

(iii) Procurement of initial capital spares within the original scope of work, in accordance with the provisions of Regulation -26.9 of these regulations;

(iv) Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law;

(v) Change in law or compliance of any existing law; and

(vi) Force Majeure events:

Provided that in case of any replacement of the assets, the additional capitalization shall be worked out after adjusting the gross fixed assets and cumulative depreciation of the assets replaced on account of de-capitalization:

Provided further that the details of works asset-wise/work-wise included in the original scope of work along with estimates of expenditure, liabilities recognized to be payable at a future date and the works deferred for execution shall be submitted along with the Petition for determination of final project cost:

28.2 **Additional Capitalisation within the original scope and after the cut-off date:**

28.2.1 Capital expenditure incurred or projected to be incurred in respect of the new project on the following counts within the original scope of work after the cut-off date may be admitted by the Commission, subject to prudence check:

(i) Liabilities to meet award of arbitration or for compliance of direction or of any statutory authority or order or decree of a court of law;

(ii) Change in law or compliance of any existing law;

(iii) Deferred works relating to ash pond or ash handling system in the original scope of work;

(iv) Any liability for works executed prior to the cut-off date, after prudence check of the details of such undischarged liability, total estimated cost of package, reasons for such withholding of payment and release of such payments, etc.

(v) Force Majeure events;

(vi) Any liability for works admitted by the Commission after the cut-off date to the extent of discharge of such liabilities by actual payments;

Provided that in case of replacement of assets deployed under the original scope of the existing project after cut-off date, the additional capitalization may be admitted by the Commission, after making necessary adjustments in the gross fixed assets and the cumulative depreciation, subject to prudence check on the following grounds:

a) Useful life of the assets is not commensurate with the useful life of the project and such assets have been fully depreciated in accordance with the provisions of these regulations;

b) Replacement of the asset or equipment is necessary on account of change in law or Force Majeure conditions;

c) Replacement of such asset or equipment is necessary on account of obsolescence of technology:

Provided that the claim shall be substantiated with the technical justification duly supported by documentary evidence like test results carried out by an independent agency in case of deterioration of assets, damage caused by natural calamities, obsolescence of technology, up-gradation of capacity for the technical reason such as increase in fault level; and

d) Replacement of such asset or equipment has otherwise been allowed by the Commission.

28.2.2 Generating Company or Transmission Licensee or Distribution Licensee shall submit the details of such additional capitalization along with auditor's certificate and required justification, technical documents, etc. along with true-up petition in the manner and format specified in Schedule-3 for approval of the Commission.

28.3 **Additional Capitalisation beyond the original scope of work:**

28.3.1 Capital expenditure, in respect of existing Generating station or Transmission system including communication system, incurred or projected to be incurred on the following counts beyond the original scope of work, may be admitted by the Commission, subject to prudence check:

(i) Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law;

(ii) Change in law or compliance of any existing law;

(iii) Force majeure events;

(iv) Any expenses to be incurred on account of need for higher security and safety of the plant as advised or directed by appropriate Government Agencies or statutory authorities responsible for national security/internal security;

(v) Any liability for works executed prior to the cut-off date, after prudence check of the details of such undischarged liability, total estimated cost of package, reasons for such withholding of payment and release of such payments etc.;

(vi) Any liability for works admitted by the Commission after the cut-off date to the extent of discharge of such liabilities by actual payments;

(vii) Usage of water from sewage treatment plant in thermal generating station;

(viii) Raising of ash dyke as a part of ash disposal system.

(ix) In case of hydro generating stations, any expenditure which has become necessary on account of damage caused by natural calamities (but not due to flooding of power house attributable to the negligence of the generating company) and due to geological reasons after adjusting the proceeds from any insurance scheme, and expenditure incurred due to any additional work which has become necessary for successful and efficient plant operation;

(x) Any additional capital expenditure which has become necessary for efficient operation:

Provided that the claim shall be substantiated with the technical justification duly supported by documentary evidence like test results carried out by an independent agency in case of deterioration of assets, damage caused by natural calamities, obsolescence of technology, up-gradation of capacity for the technical reason such as increase in fault level:

Provided further that the approval of additional capital expenditure for efficient operation shall be subject to submission of report on impact assessment done by any reputed third-party technical expert/agency on the benefits realised from previous investments under this head in the last five years;

28.3.2 Generating Company or Transmission Licensee or Distribution Licensee shall submit the details of such additional capitalization along with auditor’s certificate and required justification, technical documents, etc. along with true-up petition in the manner and format specified in Schedule-3 for approval of the Commission.

28.4 **Additional Capitalization on account of Renovation and Modernization:**

28.4.1 The generating company intending to undertake renovation and modernization (R&M) of the generating station or unit thereof for the purpose of extension of life beyond the originally recognised useful life for the purpose of tariff, shall file a petition before the Commission following the guideline specified in Schedule -3 of these regulations, for approval of the proposal with a Detailed Project Report giving complete scope, justification, cost-benefit analysis, estimated life extension from a reference date, financial package, phasing of expenditure, schedule of completion, reference price level, estimated completion cost including foreign exchange component, if any, and any other information considered to be relevant by the generating company:

Provided that the generating company making the applications for renovation and modernization (R&M) shall not be eligible for Special Allowance under Regulation 28.5 of these regulations:

Provided further that the generating company intending to undertake renovation and modernization (R&M) shall seek the consent of the beneficiaries for such renovation and modernization (R&M) and submit the response of the beneficiaries along with the Petition.

28.4.2 Where the generating company makes an application for approval of its proposal for renovation and modernisation (R&M), approval may be granted after due consideration of the reasonableness of the proposed cost estimates, financing plan, schedule of completion, interest during construction, use of efficient technology, cost-benefit analysis, expected duration of life extension, the response of the beneficiaries or long term customers, and such other factors as may be considered relevant by the Commission.

28.4.3 In the case of gas/ liquid fuel based open/ combined cycle thermal generating station after 25 years of operation from the date of commercial operation, any additional capital expenditure which has become necessary for the renovation of gas turbines/ steam turbines or additional capital expenditure necessary due to obsolescence or the non-availability of spares for efficient operation of the stations may be allowed subject to a prudence check:

Provided that any expenditure included in the renovation and modernisation (R&M) on consumables and cost of components and spares, which is generally covered in the O&M expenses during the major overhaul of gas turbines shall be suitably deducted from the expenditure to be allowed after prudence check.

28.4.4 After completion of the renovation and modernisation (R&M), the generating company, as the case may be, shall file a petition for determination of approval of R&M expenses following the guideline specified in Schedule-3 of these Regulations. Expenditure admitted by the Commission after a prudence check and after deducting the accumulated depreciation already recovered from the admitted project cost shall form the basis for the determination of tariff.

28.5 **Special Allowance for Coal-based Thermal Generating station:**

28.5.1 In the case of coal-based thermal generating stations, the generating company, instead of availing renovation and modernization (R&M), may opt to avail of a 'special allowance' in accordance with the norms specified in this Regulation, as compensation for meeting the requirement of expenses towards any additional capital expenditure covered in Regulations 28.2, 28.3 and 28.4 except for capital expenditure arising out of change in law, award of arbitration or for compliance of the directions or order of any statutory authority, or order or decree of any court of law, and force majeure after completion of 25 years from the date of Commercial operation of the generating station or a unit thereof and in such an event, an upward revision of the capital cost shall not be allowed and the applicable operational norms shall not be relaxed but the Special Allowance shall be included in the annual fixed cost:

Provided that such option shall not be available for a generating station or unit thereof for which renovation and modernization has been undertaken and the expenditure has been admitted by the Commission before the commencement of these regulations, or for a generating station or unit which is in a depleted condition or operating under relaxed operational and performance norms;

28.5.2 The Special Allowance admissible to a generating station shall be @ Rs 10.75 lakh per MW per year for the control period.

28.5.3 In the event of a generating station availing of Special Allowance, the expenditure incurred upon or utilized from Special Allowance shall be maintained separately by the generating station, and details of the same shall be made available to the Commission as and when directed.

28.5.4 The Special Allowance allowed under this Regulation shall be transferred to a separate fund for utilization towards Renovation & Modernisation and additional capitalisation as per Regulation 28.5.1 of these regulations, and the expenditure incurred or utilized from the special allowance shall be made available to the Commission as and when directed.

28.6 **Additional Capitalization on account of Revised Emission Standards:**

28.6.1 A Generating Company requiring to incur additional capital expenditure in the existing generating station for compliance of the revised emissions standards, may be admitted by the Commission, subject to prudence check based on the following details to be submitted by the Generating Company:

(i) details of proposed technology as specified by the Central Electricity Authority or alternative technology based on appropriate justification;

(ii) scope of work;

(iii) phasing of expenditure;

(iv) schedule of completion;

(v) estimated completion cost including foreign exchange component, if any;

(vi) detailed computation of indicative impact on tariff to the beneficiaries; and

(vii) any other information considered to be relevant by the Generating Company:

Provided that the Commission may grant approval after due consideration of the reasonableness of the cost estimates, financing plan, schedule of completion, interest during construction, use of efficient technology, cost-benefit analysis, and such other factors, as may be considered relevant by the Commission.

28.6.2 Generating Company shall submit the details of such additional capitalization along with auditor's certificate and required justification, technical documents, etc. along with true-up petition in the manner and format specified in Schedule-3 for approval of the Commission.

29 Consumer contribution, Deposit Work and Grant:

29.1 The expenses on the following categories of works carried out by the Generating Company or Transmission Licensee or Distribution Licensee shall be treated as specified in Regulation 29.2 of these regulations:

a) Capital works after obtaining a part or all of the funds from the users in the context of deposit works or consumer contribution works;

b) Capital works undertaken by utilizing grants or capital subsidy received from the State and Central Governments, including funds under various schemes:

Provided that a capital works or scheme of Central or State Government funded through loan convertible fully or partially to grant on fulfilment of certain conditions, shall be considered to be funded through grant to the maximum possible extent, even if such loan is not converted to grant due to non-fulfilment of such conditions by the Generating Company or Transmission Licensee or Distribution Licensee.

c) Any other grant of similar nature and such amount received without any obligation to return the same and with no interest costs attached to such subvention.

29.2 The expenses on such capital works shall be treated as follows-

a) normative O&M expenses as specified in these regulations shall be allowed;

b) the Debt:Equity ratio, shall be considered in accordance with Regulation 30 of these regulations, after deducting the amount of such financial support received;

c) provisions related to depreciation, as specified in Regulation 35 of these regulations, shall not be applicable to the extent of such financial support received;

d) provisions related to Return on Equity, as specified in Regulation 31 of these regulations shall not be applicable to the extent of such financial support received;

e) provisions related to Interest on Loan Capital, as specified in Regulation 33 of these regulations shall not be applicable to the extent of such financial support received;

30 Debt-Equity ratio

30.1 New Projects:

30.1.1 In case of a Generating Company, Transmission Licensee and Distribution Licensee, if any fixed asset is capitalised on account of capital expenditure incurred on or after April 01, 2026, for determination of Tariff the debt-equity ratio as on the date of commercial operation shall be considered on normative basis at 70:30 of the amount of capital cost approved by the Commission under Regulation 25 of these regulations, after prudence check.

Provided that:

(i) where actual equity employed is more than 30% of capital cost approved by the Commission, the amount of equity for the purpose of tariff shall be limited to 30% and the balance amount shall be considered as normative loan:

(ii) where actual equity employed is less than 30% of capital cost approved by the Commission, the actual equity shall be considered, and the balance amount in excess of 70% normative loan shall also be considered as loan:

(iii) the equity invested in foreign currency shall be designated in Indian rupees based on the exchange rate prevailing on the date(s) it is subscribed:

(iv) any grant or consumer contribution obtained for the execution of the project shall not be considered as a part of capital structure for the purpose of debt: equity ratio.

(v) Generating Company or Transmission Licensee or Distribution Licensee, as the case may be, shall submit the resolution of the Board of the company or approval of the competent authority in other cases regarding infusion of funds from internal resources in support of the utilization made or proposed to be made to meet the capital expenditure.

Explanation.- The premium, if any, raised by the Generating

Company or the Licensee while issuing share capital and investment of internal resources created out of its free reserves, for the funding of the Scheme, shall be reckoned as paid up capital for the purpose of computing return on equity, provided such premium amount and internal resources are actually utilised for meeting the capital expenditure of the Generating Station or the transmission system or the distribution system, and are within the ceiling of 30% of capital cost approved by the Commission.

30.1.2 Notwithstanding anything contained in these regulations, the equity investment to be considered in any year shall not exceed the difference between the sum of cumulative return on equity allowed by the Commission in previous years, efficiency gains and losses, incentives and disincentives, and income earned from investment of return on equity, and the cumulative equity investment approved by the Commission in previous years, unless the Generating Company or Transmission Licensee or Distribution Licensee submits documentary evidence for the actual deployment of equity and explain the source of funds for the equity.

30.1.3 In case of Transmission Licensee or Distribution Licensee, the cost of project and accordingly the debt equity ratio may be calculated considering the whole network of transmission or distribution system of the licensee, as the case may be, in place of individual line or project.

30.1.4 Any expenditure incurred or projected to be incurred on or after April 01, 2026, as may be admitted by the Commission as additional capital expenditure for determination of Tariff, and renovation and modernisation expenditure for life extension, shall be serviced in the manner specified in this Regulation.

30.2 **Existing Projects:** In case of a Generating Company, Transmission Licensee, and Distribution Licensee, if any fixed asset is capitalised on account of capital expenditure incurred prior to April 01, 2026, debt-equity ratio as allowed by the Commission for determination of tariff for the period ending March 31, 2026 shall be considered:

Provided that for the project / fixed asset put in use or declared under commercial operation prior to April 01, 2026, but where debt: equity ratio has not been determined by the Commission for determination of tariff for the period ending March 31, 2026, the Commission shall approve debt equity ratio as per regulation 30.1

of these regulations:

Provided that in case of a generating station or a transmission system or a distribution system, which has completed its useful life as on or after April 01, 2026, the excess of accumulated depreciation net of cumulative repayment of normative loan attributable to such asset, shall be utilized for reduction of the equity over the period of next five financial years in equal tranches:

Provided that any advance against depreciation allowed to be recovered during truing-up of previous years shall also be considered under accumulated depreciation for above purpose:

Provided also that depreciation admissible after the completion of useful life and the balance depreciation, if any, shall be first adjusted against the repayment of balance outstanding loan, if any and thereafter shall be utilized for reduction of equity:

Provided further that in case of de-capitalisation or retirement or replacement of assets, the equity capital approved for the said asset, shall be reduced to the extent of 30% (or actual equity component based on documentary evidence, if it is lower than 30%) of the original cost of the decapitalized or retired or replaced asset, and the debt capital approved as mentioned above, shall be reduced to the extent of actual debt component, based on documentary evidence, of the original cost of the de-capitalised or retired or replaced asset:

Provided further that the Commission shall not consider the increase in equity as a result of revaluation of assets (including land) for the purpose of computing return on equity:

Provided further that for the Generating Company or the Transmission Licensee or the Distribution Licensee formed as a result of a Transfer Scheme, the date of the Transfer Scheme shall be the effective date for the determination of equity capital.

31 **Return on Equity**

31.1 Return on equity shall be computed on the equity base determined in accordance with Regulation 30 of these regulations.

31.2 Return on equity for assets capitalized prior to 01.04.2024 shall be computed at the base rate of 15.50 % for thermal generating stations, transmission system and run-of the river hydro generating station, and at a base rate of 16.50% for distribution system, storage type hydro generating stations, pumped storage hydro generating stations and run of the river generating station with pondage.

31.3 Return on equity for assets capitalized on and after 01.04.2024 shall be computed at the base rate of 14.00 % for thermal generating stations, transmission system and run-of the river hydro generating station, and at a base rate of 15.50% for distribution system, storage type hydro generating stations, pumped storage hydro generating stations and run of the river generating station with pondage:

Provided that, return on equity in respect of additional capitalization beyond the original scope, including additional capitalization on account of emission control system, change in law and force majeure shall be computed at the bank rate as on 1st April of the year, subject to a ceiling of 14%:

31.4 The normative rate of return specified in regulations 31.2 and 31.3 above are ceiling rate and in case the Generating Company or Transmission Licensee or Distribution Licensee claims Return on Equity at a rate lower than the normative rate specified above for any particular year, then such claim for lower Return on Equity shall be unconditional. Any loss on account of such lower Return on Equity shall not be recovered latter.

31.5 The base rate of return on equity shall be reduced by 1% for such period as may be decided by the Commission, if generating station or transmission system is found to be declared under commercial operation without commissioning of any of the Restricted Governor Mode Operation (RGMO) or Free Governor Mode Operation (FGMO), data telemetry, communication system upto load despatch center or protection system based on the report submitted by SLDC. However, this does not restrict the Commission to take any penal measure against the utility defaulting more than one year.

31.6 The coal or lignite fired thermal generating stations are also eligible for a performance linked rate of return based on ramp rate during truing-up as below:

(a) Rate of return on equity shall be reduced by 0.25% in case a of failure to achieve the ramp-up and ramp-down rate of 1% of ex-bus capacity corresponding to MCR on bar per minute.

(b) An additional rate of return on equity of 0.125% shall be allowed for every incremental ramp rate of 0.50% per minute achieved over and above the ramp-up and ramp-down rate specified by Central Electricity Authority, subject to the ceiling of additional rate of return on equity of 1%.

Provided that the SLDC shall formulate the procedure for certification of Ramp Rate of thermal plants and submit for the approval of the Commission upon undertaking the due consultation of the stakeholders.

31.7 Return on equity shall be applicable to that portion of the equity only which is in use under the business operation for which gross aggregate revenue requirement is to be determined and not invested in any security or other business.

32 **Tax on Return on Equity**

32.1 The rate of return on equity as allowed by the Commission under Regulation 31 of these regulations shall be grossed up with the effective tax rate of the respective financial year. The effective tax rate shall be calculated at the beginning of every financial year based on the estimated profit and tax to be paid estimated in line with the provisions of the relevant Finance Act applicable for that financial year to the concerned Generating Company or Transmission Licensee or Distribution Licensee by excluding the income of non-regulated and the corresponding tax thereon:

Provided that in case a Generating Company or Transmission Licensee or Distribution Licensee is paying Minimum Alternate Tax (MAT) under clause 206 of the Income Tax Act, 2025, the effective tax rate shall be the MAT rate, including surcharge and cess:

Provided further that in case a Generating Company or Transmission Licensee or Distribution Licensee has opted for clause 200, the effective tax rate shall be tax rate including surcharge and cess as specified under clause 200 of the Income Tax Act, 2025.

32.2 The rate of return on equity shall be rounded off to three decimal places and shall be computed as per the formula given below:

Rate of pre-tax return on equity = Base rate / (1-t)
Where, t is applicable tax rate

32.3 The Generating Company or Transmission licensee or Distribution Licensee, as the case may be, shall true up the effective tax rate for every financial year based on actual tax paid together with any additional tax demand, including interest thereon, duly adjusted for any refund of tax including interest received from the income tax authorities on actual gross income of any financial year. Further, any penalty arising on account of delay in deposit or short deposit of tax amount shall not be considered while computing the actual tax paid for the generating company or the transmission licensee, as the case may be:

Provided that in case a Generating Company or Transmission Licensee or Distribution Licensee is paying Minimum Alternate Tax (MAT) under clause 206, the Generating Company or Transmission Licensee or Distribution Licensee, as the case may be, shall true up the grossed up rate of return on equity at the end of every financial year with the applicable MAT rate including surcharge and cess:

Provided further that in case a Generating Company or Transmission Licensee or Distribution Licensee is paying tax under clause 200, the Generating Company or Transmission Licensee or Distribution Licensee, as the case may be, shall true up the grossed up rate of return on equity at the end of every financial year with the tax rate including surcharge and cess as specified under clause 200. Provided that any under-recovery or over recovery of grossed up rate on return on equity after truing up, shall be recovered or refunded to beneficiaries or the long term customers, as the case may be, on a year to year basis.

33 Interest on loan Capital

33.1 The loans arrived at in the manner indicated in Regulation 30 of these regulations shall be considered gross normative loans for the calculation of interest on loans:

Provided that interest and finance charges on capital works in progress shall be excluded:

Provided further that in case of retirement or replacement or de-capitalisation of assets, the loan capital approved as mentioned above, shall be reduced to the extent of outstanding loan component of the original cost of such assets based on documentary evidence.

33.2 The normative loan outstanding as on 1.04.2026 shall be worked out by deducting the cumulative repayment as admitted by the Commission up to 31.3.2026 from the gross normative loan.

33.3 The loan repayment for each year of the control period shall be deemed to be equal to the depreciation allowed for the corresponding year or period.

33.4 Notwithstanding any moratorium period availed. the repayment of the loan shall be considered from the first year of commercial operation of the project and shall be equal to the depreciation allowed for the year or part of the year.

33.5 The rate of interest shall be the weighted average rate of interest computed on the basis of the actual loan portfolio or allocated loan portfolio, at the beginning of each year:

Provided that if there is no actual loan outstanding for a particular year but the normative loan is still outstanding, the last available weighted average rate of interest of the loan portfolio for the project shall be considered:

Provided further that if the generating station or the transmission system or distribution project, as the case may be, does not have any actual loan, then the weighted average rate of interest of the loan portfolio of the Generating Company or Transmission Licensee of Distribution Licensee as a whole shall be considered:

Provided also that the rate of interest on the loan for the installation of the emission control system commissioned subsequent to date of commercial operation of the generating station or unit thereof, shall be the weighted average rate of interest of the actual loan portfolio of the emission control system, and in the absence of the actual loan portfolio, the weighted average rate of interest of the Generating Company as a whole shall be considered, subject to a ceiling of bank rate:

Provided also that if the Generating Company or Transmission Licensee or Distribution Licensee, as the case may be, does not have any actual long-term loan, then the rate of interest for a loan shall be considered at bank rate of the relevant financial year.

33.6 The interest on the loan shall be computed on the normative average loan of the year by applying the weighted average rate of interest:

Provided that at the time of Truing-up, the normative average loan of the concerned year shall be considered on the basis of the actual asset capitalisation approved by the Commission for the year.

33.7 The above interest computation shall exclude interest on loan amount, normative or otherwise, to the extent of capital cost funded by Consumer Contribution, Deposit Works, Grants or Capital Subsidy, Contingency Reserves.

33.8 The finance charges incurred for obtaining capital loans from financial institutions and any amount claimed towards foreign exchange rate variation (FERV) for any Year shall be allowed by the Commission at the time of Truing-up, subject to prudent analysis. The Hedging Policy of the company should also be submitted along with the claim on account of FERV.

33.9 The Generating Company or Transmission Licensee or Distribution Licensee, as the case may be, shall make every effort to re-finance the loan as long as it results in net savings on interest and in that event, the costs associated with such re-financing shall be borne by the Beneficiaries. The net savings shall be shared between the Beneficiaries and them in the ratio of 2:1, subject to prudence check by the Commission. The changes to the terms and conditions of the loans shall be reflected from the date of such re-financing.

Provided that refinancing shall not be done if it results in net increase on interest:

Provided further that rate of interest of the refinanced loan shall be lower than the than the rate of interest of the loan, which is being refinanced;

Provided also that the re-financing shall not be subject to any adverse terms and conditions and additional cost and conditions of refinanced loan agreement shall not be considered for the purpose of determination of ARR:

Provided further that if refinancing is done and it results in net increase on interest, then the rate of interest shall be considered equal to the Base Rate as on the date on which the Petition for determination of Tariff is filed:

Provided also that the Generating Company or the Transmission Licensee or the Distribution Licensee, as the case may be, shall submit documentary evidence of the costs associated with such re-financing:

Provided also that the net savings in interest shall be computed after factoring all the terms and conditions, and based on the weighted average rate of interest of actual portfolio of loans taken from Banks and Financial Institutions recognised by the Reserve Bank of India for Indian institutions, before and after re-financing of loans:

Provided also that the net savings in interest shall be calculated as an annuity for the term of the loan, and the annual net savings shall be shared between the entity and Beneficiaries in the specified ratio.

34 Foreign Exchange rate Variation

34.1 The Generating Company or Transmission Licensee or Distribution Licensee may hedge foreign exchange exposure in respect of the interest on foreign currency loan and repayment of foreign loan acquired for the generating Station or the transmission system or distribution system, in part or in full at its discretion.

34.2 The Generating Company or Transmission Licensee or Distribution Licensee shall be permitted to recover the cost of hedging of foreign exchange rate variation corresponding to the foreign debt, in the relevant year as expense, subject to a ceiling of 1% of the foreign exchange component after prudence check by the Commission. Any extra rupee liability corresponding to such variation shall not be allowed against the hedged foreign debt.

34.3 To the extent that the foreign exchange exposure is not hedged, any extra rupee liability towards interest payment and loan repayment corresponding to the foreign currency loan in the relevant year shall be allowed subject to prudence check by the Commission, provided it is not attributable to such Generating Company or Transmission Licensee or Distribution Licensee or its suppliers or contractors.

34.4 The Generating Company or ESSD or Licensee shall follow prudent contract practice by incorporating necessary safeguard clauses against risk of price increment on account of Foreign Exchange Rate Variation on imported material

34.5 Any extra rupee liability towards Foreign Exchange Rate Variation on import of material may be disallowed.

Explanation: The incidence of Foreign Exchange Rate Variation is invariably expected to be negligible, unless such equipment is not available in India.

35 **Depreciation**

35.1 The Generating Company, Transmission Licensee and Distribution Licensee shall be permitted to recover depreciation on the value of fixed assets used in their respective businesses, computed in the following manner:

(i) The approved original cost of the project / fixed asset shall be the value base for calculation of depreciation:

Provided also that depreciation shall be allowed on the entire capitalised amount after reducing the approved original cost of the retired or replaced or de-capitalised assets.

(ii) The depreciation for Existing Capital Schemes or Existing Assets shall be computed annually, based on straight line method at the rates specified in the Annexure — I to these Regulations:

Provided that the Generating Company or Transmission Licensee or Distribution licensee shall ensure that once the individual asset is depreciated to the extent of 70%, the remaining depreciable value as on 31st March of the year closing shall be spread over the balance useful life of the asset including the extended life, if any, allowed under renovation & modernization:

Provided also where category specific 'block of assets' has been admitted by the Commission in the previous year(s), in terms of repealed regulations, such block of assets shall be considered for computing the depreciation. The Generating Company or Transmission Licensee or Distribution Licensee shall maintain separate fixed asset register for such block of assets:

Provided that the Generating Company or Transmission Licensee or Distribution licensee shall submit all such details or documentary evidence as may be required, to substantiate the above claims.

Explanation: The term "Existing Capital Schemes" or "Existing Assets" here means the Capital Schemes or the Assets, including Non-DPR schemes which has been declared commercial operation or put to use on a date prior to 01.04.2026.

(iii) The depreciation for New Capital Schemes or New Assets shall be computed annually, based on straight line method at the rates specified in the Annexure — II to these Regulations:

Provided that the Generating Company or Transmission Licensee or Distribution licensee shall ensure that the remaining depreciable value as on 31st March of the year closing after a period of 15 years from the effective date of commercial operation or put to use of the asset, shall be spread over the balance useful life of the asset including the extended life, if any, allowed under renovation & modernization:

Provided also the Generating Company or Transmission Licensee or Distribution licensee shall submit all such details or documentary evidence as may be required, to substantiate the above claims.

Explanation: The term "New Capital Schemes" or "New Assets" here means the Capital Schemes or the Assets, including Non-DPR schemes achieving its commercial operation on or after 01.04.2026.

(iv) The remaining depreciable value as on 1st April shall be worked out by deducting the cumulative depreciation and Advanced Against Depreciation, if any, as admitted by the Commission upto 31st march of the previous year, from the gross depreciable value of the assets:

(v) Land other than the land held under lease and the land for a reservoir in case of a hydro generating station pumped storage hydro project shall not be a depreciable asset and its cost shall be excluded from the capital cost while computing depreciable value of the assets.

(vi) The salvage value of the asset shall be considered at 10.00% of the allowable capital cost and depreciation shall be allowed up to a maximum of 90.00% of the allowable capital cost of the Asset:

Provided that the Generating Company or Transmission Licensee or Distribution Licensee shall submit certification from the Auditor for the capping of depreciation at ninety per cent of the allowable capital cost of the asset:

Provided further that the salvage value for IT equipment and software shall be considered as NIL or 0.00% and 100% or entire value of the assets shall be considered depreciable:

Provided also that in case of hydro generating station, salvage value shall be as provided in the agreement, if any, signed by the developers with the State Government:

Provided also that any depreciation disallowed on account of lower availability of the generating station or generating unit or transmission system as the case may be, shall not be allowed to be recovered at a later stage during the useful life or the extended life.

(vii) Where the Emission Control System is implemented within the original scope of the generating station and the date of commercial operation of the generating station or unit thereof and the date of operation of the Emission Control System are the same, depreciation of the generating station or unit thereof including the Emission Control System shall be computed in accordance with clauses (i) to (vi) of this Regulation.

(viii) Depreciation of the Emission Control System of an existing or a new generating station or unit thereof where the date of operation of the emission control system is subsequent to the date of commercial operation of the generating station or unit thereof, shall be computed annually from the date of operation of such emission control system based on straight line method, with salvage value of 10%, over a period of —

a) twenty-five years, in case the generating station or unit thereof is in operation for fifteen years or less as on the date of operation of the emission control system; or

b) balance useful life of the generating station or unit thereof plus fifteen years, in case the generating station or unit thereof is in operation for more than fifteen years as on the date of operation of the emission control system; or

c) ten years or a period mutually agreed by the generating company and the beneficiaries, whichever is higher, in case the generating station or unit thereof has completed its useful life.

(ix) Depreciation shall be chargeable from the first year of operation. In case of operation of the asset for part of the year, depreciation shall be charged on prorate basis. However, during tariff determination depreciation for ensuing years shall be computed based on average of opening and closing value of assets.

Provided that depreciation shall be re-computed for assets capitalised at the time of Truing up of each year of the control period, based on the Audited Accounts and documentary evidence of assets capitalised by the Petitioner, subject to the prudent analysis by the Commission.

(x) The depreciation on capital investment schemes undertaken by Generating Companies shall be allowed proportionately corelated to the balance operational life of the generating station:

Provided that, in case the balance operational life of the generating station is less than 10 years, Generating Company shall take the consent of its beneficiary before incurring any capital expenditure under DPR-Scheme.

(xi) The Generating Company or Transmission Licensee or Distribution Licensee shall submit the depreciation computations separately for assets added upto March 31, 2026 and assets added on or after April 1, 2026.

(xii) Generating Company or Transmission Licensee or Distribution Licensee have to submit a summary of their asset register duly certified by statutory auditor as per the format specified under Annexure-10 along with their tariff as well as true-up petition.

36 **Operation & Maintenance Expenses:**

36.1 Operation and Maintenance or O&M expenses includes the following:

(i) Repair & Maintenance (‘R&M”) Expenses including spares, consumables and related outsourced expenses, if any;

(ii) Administrative and General Expenses including rent, lease charge, legal charge, consultation fees, auditor’s fees, insurance fees, outsourced expense, if any, and any other expenses necessary and incidental to the business of electricity generation, distribution and transmission, except penalty levied under this Act or any other Act; and

(iii) Employee expenses includes expenses of own employees and costs of outsourced manpower, if any:

Provided that in case of a generating company or licensee owned by the Central or State Government, the impact on account of implementation of wage or pay revision shall be allowed at the time of truing-up of tariff:

Provided further that all statutory fees including licence and filing fees payable in terms of the Act shall be allowed separately during truing-up:

Provided also that water charges in respect of generating stations shall not be a part of O&M expense and shall be computed separately:

Provided also that, for integrated mine(s), the O&M expenses shall not include the mining charge paid to the Mine Developer and Operator, if any, engaged by the generating company and the mine closure expenses:

Provided also that any expenditure on acquiring the minor items or the assets including tools and tackles, furniture, air-conditioners, voltage stabilizers, refrigeratorso, etc. bought after cut-off date of the project, any spare of capital nature valuing upto Rs. 10 lakh shall be part of O&M expenses:

Provided also that any specific kind of O&M expense for the activities, which do not fall under usual business activity of the generating company or licensee, as the case may be, but have been carried out as per direction of the Commission or Government shall be allowed separately during truing-up, subject to prudent analysis of such expenses.

36.2 Generating Station

36.2.1 O&M expenses for generating station shall be computed based on the installed capacity considering the norms specified in Schedule-6 of these regulations. Any gain /loss on account of O&M expenditure will be shared as per Regulation 11 of these regulations during truing-up.

36.2.2 Water charges for thermal generating stations and statutory fees / charges, excluding any penal charges, payable by the generating stations shall be allowed separately:

Provided that water charges shall be allowed based on water consumption depending upon type of plant and type of cooling water system, subject to prudent analysis. The details regarding the same shall be furnished along with the petition for tariff and true-up.

36.3 Transmission System:

36.3.1 O&M expenses for transmission system shall be computed based on the transmission line length and number of Bays in the sub-station considering the norms specified in Schedule-6 of these Regulations. Any gain /loss on account of O&M expenditure will be shared as per Regulation 11 of these regulations during truing-up.

36.3.2 For the purpose of applying normative O&M expenses under regulation 36.3.1 of these regulations, a 'Bay' shall mean a set of accessories that are required to connect an electrical equipment such as Transmission Line, Bus Section Breakers, Potential Transformers, Power Transformers, Capacitors and Transfer Breaker and the feeders emanating from the bus at sub-Station of Transmission Licensee. Further, the Bays referred to above shall include only the Bays at the Transmission substation and shall exclude any Bays of the Generating Station switchyard whose maintenance is the responsibility of the Generating Company:

Provided that for computing the allowable O&M expenses for any year, the average of opening and closing circuit kms of transmission line, numbers of Bays and transformation capacity during the financial year shall be considered:

Provided further that at the time of truing-up, the allowable O&M expenses for any year shall be based on the norms for O&M expenses specified by the Commission in these Regulations and documentary evidence of assets capitalised by the Petitioner, subject to the prudent analysis by the Commission:

Provided also that the number of Bays considered for allowing O&M expenses shall exclude the unutilized Bays, if any:

Provided also that, any statutory charges and fees payable by the Transmission licensee, except any penal charges are to be allowed separately, subject to prudent check by the Commission. Transmission Licensee shall furnish details of such payable statutory charges and /or fees in its petition.

36.4 Distribution System:

36.4.1 O&M expenses for Distribution Business of a licensee shall include the manpower expenses, repair & maintenance expenses including consumables and spares, if any, and administrative & general expenses incidental to the distribution business. Norms of distribution O&M expenses has been expressed as a percentage of Gross Fixed Asset (GFA) as specified in Schedule-6 of these Regulations:

Provided that, for computing the allowable Operation & Maintenance expenses for any year, the average of opening and closing Gross Fixed Asset (GFA) for the financial year shall be considered:

Provided further that at the time of truing-up, the allowable Repair & Maintenance expenses for any Year shall be based on the percentage norms specified in the Schedule-6 and the admissible GFA:

Provided also that fixed asset retired/de-capitalised or unutilized/not-in-use shall be deducted for arriving at the applicable GFA for computing the O&M expense. Distribution licensee shall furnish such details along with its petition for tariff and true-up.

36.4.2 Any gain /loss on account of total O&M expenditure will be shared as per Regulation 11 of these regulations during Annual Performance Review.

36.4.3 In addition to the above O&M expenses, distribution licensee may propose for any specific expenditure under OPEX model through detailed justification and cost benefit analysis in its tariff petition. Such expenditure may be allowed by the Commission subject to prudence check. During truing-up, licensee shall also submit details of such expenditure and cost-benefit analysis supported by certificate from the auditor:

36.4.4 Provided that, if such expenditure is planned after issuance of tariff order, licensee shall take approval of such plan from the Commission before incurring such expenditure. Such expenditure, if approved, shall be considered during truing-up.

37 Interest on Working Capital

37.1 **Generation**

(a) In case of coal based generating stations, working capital shall cover:

(i) Cost of coal towards stock for 10 days for pit head generating stations and 20 days for non-pithead generating stations for generation corresponding to the normative annual plant availability factor or maximum coal stock storage capacity, whichever is lower;

(ii) Advance payment for 30 days towards cost of coal for generation corresponding to the normative annual plant availability factor;

(iii) Cost of secondary fuel oil for two months for generation corresponding to the normative annual plant availability and in case of use of more than one secondary fuel oil, cost of oil stock for main secondary fuel oil;

(iv) O&M expenses including employee cost and water charges for one month;

(v) Maintenance spares @ 20% of O&M expenses including water charges; and

(vi) Receivables equivalent to 45 days of capacity charges and energy charges for sale of electricity computed on the normative annual availability factor and excluding incentives, if any:

Provided that in case the due date of payment as per the PPA agreement is more than 45 days, receivable equivalent to the due date shall be considered:

Provided further that in case of own generating station of any licensee, no amount shall be allowed towards receivables, to the extent of supply of power by the generation business to the distribution business, in computation of working capital in accordance with these Regulations.

(b) In case of Emission Control System of coal based thermal generating stations, working capital shall cover:

(i) Cost of limestone or reagent towards stock for 20 days corresponding to the normative annual plant availability factor;

(ii) Advance payment for 30 days towards the cost of reagent for generation corresponding to the normative annual plant availability factor;

(iii) Operation and maintenance expenses in respect of the emission control system for one month;

(iv) Maintenance spares @20% of operation and maintenance expenses in respect of emission control system.

(c) In case of hydro generating stations and pumped storage projects, working capital shall cover:

(i) O&M expenses including employee cost for one month;

(ii) Maintenance spares @ 15% of O&M expenses;

(iii) Receivables equivalent to 45 days of Annual Fixed cost, excluding incentive, if any:

Provided that in case of own generating station of any licensee, no amount shall be allowed towards receivables, to the extent of supply of power by the generation business to the distribution business, in computation of working capital in accordance with these Regulations.

(d) In case of own generating station of a distribution licensee, the working capital requirement under clause (a), (b) and (c) above shall be further adjusted with the balance amount of cash security deposit, if any, held by the licensee after meeting the working capital requirement of its distribution business.

(e) Interest on working capital shall be allowed at a rate equal to the MCLR or any redefined term thereof by SBI from time to time being in effect applicable for one-year period, as prevalent on 1st April of the financial year in which the Petition is filed plus 250 basis points.

(f) During truing-up, the working capital requirement and interest thereon shall be re-computed on the basis of the followings:

(i) scheduled generation or targeted availability of generating Station, whichever is lower;

(ii) actual average stock of coal or lignite and limestone or normative stock of coal or lignite and limestone of the generating Station, whichever is lower;

(iii) revised normative Operation & Maintenance expenses and actual Revenue from sale of electricity excluding incentive, if any, and other components of working capital approved by the Commission in the Truing-up before sharing of gains and losses; and

(iv) the rate of interest equal to the MCLR or any redefined term thereof by SBI from time to time being in effect applicable for one-year period, as on 1st April of the respective financial year plus 250 basis points.

37.2 **Transmission:**

a) The working capital requirement of the Transmission Licensee shall cover:

(i) O&M expenses including employee cost for one month;

(ii) Maintenance spares @ 15% of the O&M expense;

(iii) Receivables equivalent to 45 days transmission charge computed on target availability and excluding incentive, if any.

minus

(iv) Amount held as security deposits in cash, if any, from Transmission System Users

b) Interest on working capital shall be allowed at a rate equal to the MCLR or any redefined term thereof by SBI from time to time being in effect applicable for one-year period, as prevalent on 1st April of the financial year in which the Petition is filed plus 250 basis points:

c) During truing-up, the working capital requirement and interest thereon shall be re-computed on the basis of the followings:

(i) the values of components of working capital approved by the Commission in the truing up before sharing of gains and losses; and

(ii) the rate of interest equal to the MCLR or any redefined term thereof by SBI from time to time being in effect applicable for one-year period, as on 1st April of the respective financial year plus 250 basis points.

37.3 **Distribution:**

a) The working capital requirement of the Distribution Licensee shall cover:

(i) O&M expenses including employee cost for one month;

(ii) Maintenance spares @ 15% of the O&M expense

(iii) Receivables equivalent to 45 days of expected revenue from consumers at the prevailing tariff rates

(b) Any cash security deposit from consumers held with distribution licensee shall first be used to meet working capital requirement of its distribution business. Balance amount of cash security deposit, if any, will then be utilized to meet working capital requirement for its own generating station:

Provided that if there is any balance cash security deposit held with licensee after meeting the working capital requirement of its distribution business and own generating station(s), interest on such amount will be considered as non-tariff income and to be shown separately:

Provided further that for the purpose of truing up for any year, the working capital requirement shall be re-computed on the basis of the values of components of working capital approved by the Commission in the truing up before sharing of gains and losses.

(c) Interest on working capital shall be allowed at a rate equal to the MCLR or any redefined term thereof by SBI from time to time being in effect applicable for one-year period, as prevalent on 1st April of the financial year in which the Petition is filed plus 250 basis points:

Provided that at the time of truing up for any year, interest on working capital shall sbe allowed at a rate equal to the MCLR or any redefined term thereof by SBI from time to time being in effect applicable for one-year period, as on 1st April of the respective financial year plus 250 basis points.

(d) In addition to interest on working capital, the licensee shall be allowed interest on cash security deposit taken by it at the rate in terms of the West Bengal Electricity Regulatory Commission (Miscellaneous Provisions) Regulations 2013 on actual basis.

38 Interest on Consumer Security Deposit:

38.1 Interest shall be allowed on the amount held as security deposit held in cash from the consumers at the rate specified in the West Bengal Electricity Regulatory Commission (Miscellaneous Provisions) Regulations 2013.

Provided that at the time of Truing-up, the interest on the amount of security deposit for the year shall be considered on the basis of the actual interest paid by the Licensee during the year, subject to prudence check by the Commission.

39 Statutory Fees and Charges

39.1 The licensee and generating company shall be entitled to take into account any statutory fee or charge paid by it under these regulations as expenses in the determination of tariff:

Provided that the expenditure against any statutory provision such as taxes, duties, cess etc. shall only be passed through truing-up on submission of assessment order or any valid document mentioning the reasons of such payment.

39.2 Any expenditure arising out of contravention or non-compliance of any statutory provision under any Act or rules or regulations or non-compliance of any order of judicial body or statutory body shall not be allowed to be passed through tariff and for that purpose, the licensee or the generating company shall specifically mention such expenditure in its petition for true-up along with the relevant order of the authority:

Provided that while submitting application for true-up, the licensee or generating company shall submit the details along with the documents of the concerned authorities for any payment made under the head of penalty, compensation or fine or penal taxes/ duties/cess or disincentive or excess cess / royalty or under the name of violation or non-compliance or contravention of any provision of any statue or any statutory body, and in case no such payment has been made in the concerned year, the applicant has to give a clear declaration for such non-payment.

39.3 The Commission may withhold any amount for non-compliance of its directives or non-submission of information properly as sought for in the regulations.

40 Bad and Doubtful Debts

40.1 The Commission may allow such amount of bad debts during truing-up as actually had been written off in the latest available audited accounts of the Generating Company or Transmission Licensee or Distribution Licensee subject to a ceiling of 0.5% of the annual gross sales at the end of the current year.

Provided that in case of restructuring or merger of entities, the Commission may relax the ceiling for once only as deemed fit and proper:

41 Income from other sources / Non-tariff Income

41.1 Income from other sources or non-tariff income shall be shown against each type of income separately and it shall be clearly mentioned in books of account for each type separately and distinctly.

41.2 The Non-Tariff Income shall include:

i) Income from rent of land or buildings;

ii) Income from sale of scrap;

iii) Income from investments;

iv) Income from sale of ash/rejected coal;
v) Income from parallel operation charge;
vi) Income from meter-rent;
vii) Interest income on advances to suppliers/contractors;
viii) Rental from staff quarters;
ix) Rental from contractors;
x) Income from hire charges from contactors and others;
xi) Income from advertisements;
xii) Income from sale of tender documents;
xiii) Prior period income;
xiv) Supervisory charges for contractual works;
xv) Excess found on physical verification;
xvi) Any other Non-Tariff Income:

Provided that the interest earned from investments made out of Return on Equity corresponding to the regulated Business of the Generating Company shall not be included in Non-Tariff Income:

Provided further that, interest on Unforeseen Exigency Fund and Development Fund shall be kept in the respective funds and not to be included in Non-Tariff Income.

41.3 Income from other sources or non-tariff income shall be allocated to that part of electricity business of a licensee or generating company under which such income has taken place:

Provided that where such segregation is not possible then it will be allocated in proportion to gross aggregate revenue requirement for each part of electricity business.

42 Sharing of income from other business

42.1 Where the generating company or licensee has derived any extra means of income from Incidental Services then an amount equal to 40% of the revenue from such other services after deducting the direct and indirect costs attributed to such Incidental Services shall be deducted from the gross aggregate revenue requirement of the licensee.

42.2 Where the generating company or licensee has engaged in any other business for optimum utilization of assets of its core business, an amount equal to two-fifth of the revenues from such other business after deduction of all direct and indirect costs attributed to such other business shall be deducted from the gross aggregate revenue requirement of the licensee.

Provided that the licensee shall follow a reasonable basis for allocation of all joint and common costs between the regulated business and the other business and shall submit the allocation statement to the Commission along with his application for determination of tariff.

Provided further that where the sum total of the direct and indirect costs of such other business exceed the revenues from such other business or for any other reason, no amount shall be allowed to be added to the aggregate revenue requirement of the licensee on account of such other business.

43 **Rebate**

43.1 For payment of bills of Generation Tariff or Transmission charges

(i) on presentation of bills, through Letter of Credit a rebate of 2% shall be allowed; and

(ii) where payments are made other than through letter of Credit within a period of one month from presentation of bill, a rebate of 1% on billed amount, excluding the taxes, cess, duties, etc., shall be allowed.

43.2 For payment of bills of retail Tariff by the consumers within due date, a rebate of 1% on the billed amount, excluding the taxes, cess, duties, etc., shall be allowed.

43.3 For any payment made within due date, an additional rebate of 1% of the amount of energy bill excluding meter rent, taxes, duties, levies and arrears (not being arrears due to revision of tariff) will be applicable, if such payment is made through e-payment gateway using (i) debit card or (ii) credit card or (iii) internet banking or (iv) NEFT/ RTGS or (v) National Automated Clearing House (NACH) or (vi) electronic clearing system or (vii) any other mode viz., valued card wallet system or USSD or Instapay of banks or (viii) online payment through mobile software application which is an optional payment scheme to the consumer for payment of energy bill to any licensee other than payment mode through own cash counter of the licensee. The applicable e-payment gateway service charge, if any, to the service provider is to be borne by the licensee. Licensee shall maintain proper accounting of such charges which shall be adjusted during APR after prudence check:

Provided that such additional 1% rebate is not applicable for payment through Letter of Credit (LC) mechanism maintained with any bank by the consumer:

Provided also that any additional charges claimed by banks or service provider like LC charges, charge for NEFT/ RTGS, etc. are to be paid by the consumers themselves.

Illustration: Any payment to the licensee through LC mechanism shall not be qualified for additional rebate of 1% as revenue collection through LC mechanism is not always free from manual intervention from the licensee's end even when payment is made through the modes (i) to (viii) mentioned in this regulation and depends upon the agreement / arrangement between the LC issuing bank and the consumer, leaving a possibility of non-payment of full amount of the bill when it exceeds the LC amount.

43.4 All rebates or incentives earned by the Generating Company or Transmission Licensee or Distribution Licensee shall be considered under its Non-Tariff Income, while all rebates or incentives given by the Generating Company or Transmission Licensee or Distribution Licensee shall be allowed as an expense for the Generating Company or Transmission Licensee or Distribution Licensee, as the case may be.

44 Delayed Payment Surcharge

44.1 In case the payment of bills of Generation Tariff or Transmission Charges by the beneficiary is delayed beyond the due date, Delayed Payment Surcharge at the 'Base Rate of Delayed Payment Surcharge' shall be payable on the payment outstanding for the first month of default or part thereof, notwithstanding anything to the contrary as may have been stipulated in the Agreement or Arrangement with the Beneficiaries:

Provided that the rate of Delayed Payment Surcharge for the successive months of default shall increase by 0.5 percent for every month of delay or part thereof subject to the condition that the Delayed Payment Surcharge shall not be more than three percent higher than the Base Rate of Delayed Payment Charge at any time:

Provided further that the due date of payment shall be in accordance with the Power Purchase Agreement, Power Supply Agreement or Transmission Service Agreement, as the case may be, and if not specified in the agreement it shall be 45 days from the date of presentation of bill by such generating company or transmission licensee:

Provided further that the rate at which Delayed Payment Surcharge shall be payable, shall not be higher than the rate of Delayed Payment Surcharge specified in the Agreement, if any.

44.2 In case the payment of bills of retail Tariff by the consumers is delayed beyond the due date, a Delayed payment Surcharge (DPSC) shall be applicable on the billed amount, including the taxes, cess, duties, etc. and shall be levied on simple interest basis at the following rates:

Period of delay	DPSC rate
Upto first 90 days	10.00 % per annum
From 91 days to 180 days	12.00 % per annum
More than 181 days	15.00 % per annum

Provided that for L&MV agriculture consumers no DPSC rate shall be applicable for delay upto first 90 days.

Provided further that, these delayed payment surcharges are without prejudice to the provisions of disconnection under the Act and the Regulations made thereunder. However, if necessary, Commission through any tariff order or any other order may, from time to time, change the applicable rate in percentage for determination of delayed payment surcharge.

44.3 Such Delayed Payment Charge and Interest on Delayed Payment earned by the Generating Company, or the Licensee shall not be considered under its Non-Tariff Income.

44.4 Such Delayed Payment Charge paid or payable by the Distribution Licensee to the Generating Company or the Transmission Licensee shall not be allowed as an expense for such Distribution Licensee.

44.5 All payments by a Distribution Licensee to a Generating Company for power procured from it or by a user of a transmission system to a Transmission Licensee shall be first adjusted towards Delayed Payment Charge and thereafter, towards monthly charges, starting from the longest overdue bill.

44.6 All the bills payable by a Distribution Licensee to a Generating Company or a Transmission Company shall be time tagged with respect to the date and time of submission of the bill and the payment made by the Distribution Licensee shall be adjusted first against the oldest bill and then to the second oldest bill and so on, so as to ensure that payment against a bill is not adjusted unless and until all bills older than it have been paid for:

Provided that any adjustment towards Delayed Payment Charge shall be done in the manner as specified in Regulation 46.5.

45 Reserve for Unforeseen Exigencies

45.1 The Generating Company or Transmission Licensee or Distribution Licensee may provide and maintain a reserve for dealing with unforeseen exigencies up to 0.25% of the value of gross fixed assets at the beginning of the year annually and the provision made for the year may be allowed in their Aggregate Revenue Requirement subject to an overall ceiling of 5% of the value of gross fixed assets at the beginning of the year. The existing amount of contingency reserve in the books of accounts of the Generating Company or Transmission Licensee or Distribution Licensee, if any, will be considered while arriving at the overall ceiling as stated herein.

45.2 For failure to comply with the provisions of the Regulation 46 of these regulations, double the amount allowed under the head reserve for unforeseen exigencies in any tariff order of a year shall be withheld from the re-determined ARR during Truing-up of any year.

46 Development Fund

46.1 The Commission, at its discretion, may allow the Generating Company or Transmission licensee or Distribution Licensee to make a provision in its annual revenue requirement, not exceeding 5% of its annual fixed charge, for development of its infrastructure directly related to equipment for generating stations or for transmission network or for distribution network for supplyof electricity to the licensees or consumers, as the case may be, and to recover the same through tariff.

46.2 The amount so allowed for recovery through tariff under regulation 40.1 shall be kept in a fund to be known as Development Fund to be created by the Generating Company or Transmission licensee or Distribution Licensee, as the case may be, and utilised exclusively for the purposes mentioned in regulation 46.1 of these regulations.

46.3 The assets created from the Development Fund shall be maintained under a separate asset register with proper book value under prudent accounting practice along with unique codification of each asset separately.

46.4 Accounts of the Development Fund shall be maintained separately, audited by certified Auditor and the Audit Report shall be submitted to the Commission every year.

46.5 For the assets created through such “development fund” shall not be considered for computation of return on equity, interest on loan and depreciation.

47 Research and Development Expenditure

47.1 The Commission may allow a licensee or a generating company an expenditure on account of Research & Development upto 0.10% of the ARR of the preceding year forthe year for which ARR is determined.

47.2 Such expenditure on Research & Development will be allowed only when there is prior project-wise approval from the Commission or where the Commission has directed to undertake any such project.

47.3 Such project(s), if approved or directed by the Commission, shall be conducted through own in-house resource or through recognized Research Institute(s) under Government of India or State Government or any reputed academic institution or through any reputed consultant provided the selection of the consultant has been done through competitive bidding.

47.4 The asset created through such expenditure shall be considered as an asset created through consumer contribution and thus will not be entitled to Return on Equity, interest on loan and depreciation under these regulations.

48 Investment and other conditions of Reserves and Funds

48.1 The sum appropriated to the Reserve for Unforeseen Exigencies and Development Fund shall be invested separately against each such head prudently in securities authorised under the Indian Trusts Act, 1882 (2 of 1882) or in any financial instruments of Nationalized bank, keeping the risk, rate of return and liquidity factors in view within a period of six months of the close of the year of accounts for which such appropriation is allowed. Such investment will be done in a manner so that about 50% of such investment shall be in long term instruments and balance in short term deposits excluding those specific amounts against which the Commission has issued any specific direction.

48.2 The interest accrued from such investment shall be reinvested under the same reserve / fund.

48.3 The reinvestment from interest shall be maintained separately under separate head and it shall not be treated under any ceiling as specified in regulation 43.1 or regulation 44.1 of these regulations.

48.4 To decide the mode of use of accrued interest, prior approval of the Commission maybe taken annually through application of tariff or True-up preceding the year in which such interest accrues.

48.5 Accrued interest after disbursement shall be invested within a month of receipt of the same unless invested on a cumulative basis.

48.6 The aforesaid reserve or fund shall be drawn upon only to meet such charges as the Commission may approve.

48.7 For facilitating distinct operation of the above funds and reserves the licensee or generating company shall open separate bank accounts under nationalized/ scheduled banks for Reserve for Unforeseen Exigencies and Development Fund. The licensee or generating company shall deposit the amount on the head of Reserve for Unforeseen Exigencies and Development Fund on monthly basis from the monthly revenue income in proportion to the amount of such head in the total revenue recoverable through tariff for the year concerned. Any adjustment from these two accounts for a year for over or under deposition shall be done within three months from the date of the issuance of the order of true-up of the concerned year. All the transactions and investment / reinvestment of the fund or reserve shall be routed through this account only in accordance with these regulations, and specific order of the Commission.

48.8 The reserve for unforeseen exigencies or development fund can be utilized for the purpose of providing service directly or indirectly exclusively to the consumers of the State.

48.9 If any generating company create any asset from the development fund or reserve for unforeseen exigencies and subsequently such asset is not used to supply electricity to any licensee of the State due to discontinuance of any PPA then such generating company is required to refund part of such investment to the account of development fund of the concerned licensee by an amount equal to balance residual amount of depreciated value of such asset under discussion.

48.10 The generating company or licensee shall maintain separate accounts of the Reserve for Unforeseen Exigencies and Development Fund. It is the duty of the generating company and licensee to get such accounts audited by a certified Auditor, and submit such audit report to the Commission every year.

49 De-commissioning of asset

49.1 In case a generating station or unit thereof, or a transmission system or distribution system including communication systems or element thereof after it is certified by CEA or any other statutory authority or on order of court of law, that any asset cannot be operated or needs to be replaced on account of environmental concerns or safety issues or system upgradation or a combination of these factors not attributable to the Generating Company or Transmission Licensee or Distribution Licensee, the unrecovered depreciable value may be allowed to be recovered on a case-to-case basis after duly adjusting the salvage value or realisation value, whichever is higher, post disposal of such project:

Provided that the manner of recovery, including a number of instalments in which such unrecovered depreciation will be allowed, shall be specified by the Commission on a case-to-case basis.

Provided further that no carrying cost shall be allowed on any delay associated with such recovery.

50 Allocation of different elements of ARR

50.1 While any element of ARR is required to be allocated among distribution, transmission, generation and trading business of any licensees, then the Commission will follow the allocation in accordance with the following methodology:

(i) The actual amount of expenditure or entitlement on different business as proposed by the licensee or generating company shall be subject to prudence check by the Commission;

(ii) Where the licensee or generating company applies for allocation procedure with any reasoning on any element of ARR, the Commission may accept it, if it is found reasonable;

(iii) Where the Commission does not agree to any allocation procedure by generating company or licensee or does not have the allocation from generating company or licensee, the Commission will allocate such element of ARR in accordance with any of the following methodologies:

a) Equity and reserve for unforeseen exigencies on the basis of gross fixed asset.

b) Depreciation on the basis of net fixed asset.

c) Other elements of ARR on the basis of purpose of such element. For loan, loan repayment and interest, the purpose ofthe loan shall be mentioned clearly in order to allocate properly its impact on generation, distribution system, transmission system and trading activity separately. Where no such allocation is possible on the basis of purpose, then such allocation will take place on the basis of proportion to gross aggregate revenue requirement for each type of business.

d) Any method, other than (a) to (c) above, found to be reasonable subject to mentioning of such specific reasons.

(iv) While adjusting through recovery or refund arising out of APR, such adjustment amount is to be allocated between different businesses of the licensee in accordance with the proportion of the net aggregate revenue determined under APR for each type of business.

CHAPTER – 5

GENERATION

51 Applicability

51.1 The Regulations specified in this Chapter shall apply to the determination of Tariff for supply of electricity to a Distribution Licensee from conventional sources of generation including hydro generating stations of capacity exceeding 25 MW, whose tariff is being determined by the Commission under section 62 of the Act.

Provided that determination of Tariff for supply of electricity to a Distribution Licensee from Renewable Energy sources of generation shall be in accordance with terms and conditions specified in the relevant Regulations / orders of the Commission.

51.2 The Commission shall be guided by the terms and conditions contained in this Chapter in determining the Tariff for supply of electricity by a Generating Company to a Distribution Licensee, in the following cases:

a) where such Tariff is pursuant to a power purchase agreement or arrangement entered into subsequent to the date of coming into effect of these Regulations; or

b) where such Tariff is pursuant to a power purchase agreement or arrangement entered into prior to the date of coming into effect of these Regulations, and the Commission has approved such agreement or arrangement, and the agreement or arrangement envisages that the Tariff shall be based on the Tariff Regulations prevailing at that time; or

c) where the Distribution Licensee is engaged in the Business of generation of electricity, in determining the transfer price at which electricity is supplied by the Generation Business of the Distribution Licensee to its Retail Supply Business.

52 Petition for determination of Generation Tariff

52.1 A Generating Company shall file a Petition for determination of Tariff for supply of electricity to Distribution Licensees in accordance with the provisions of Chapter-3 of these Regulations.

52.2 Tariff in respect of a Generating Station, under these Regulations may be determined Stage-wise, Unit-wise or for the whole Generating Station:

Provided that the terms and conditions for determination of Tariff for Generating Stations specified in this Chapter shall apply in like manner to Stages or Units or the Generating Station, as the case may be.

52.3 Where the Tariff is being determined for a Stage or Unit of a Generating Station, the Generating Company shall adopt a reasonable basis for allocation of capital cost relating to common facilities and allocation of joint and common costs across all Stages or Units, as the case may be:

Provided that the Generating Company shall maintain an Allocation Statement providing the basis for allocation of such costs, which shall be duly audited and certified by the statutory auditors and submit such audited and certified statement to the Commission along with the Petition for determination of Tariff:

Provided further that in case the Commission has undertaken study for allocating common cost to unit/station of Generating Company, then such Generating Company shall allocate the cost as per Commission's Order in that regards.

52.4 In the case of existing generating Stations/Units, the Commission may allow the Generating Company; the Tariff based on the approved capital cost as on April 1, 2026 and projected additional capital expenditure for the ensuing Years:

Provided that, approved project cost for tariff determination shall be in accordance with regulation 25.9 of these regulations:

Provided further that the Generating Company shall continue to bill the Beneficiaries at the Tariff approved by the Commission and applicable as on March 31, 2026 for the period starting from April 1, 2026 till approval of Tariff by the Commission in accordance with these Regulations.

52.5 The Generating Company shall file the Petition for determination of provisional Tariff for new Generating Station, at least two months prior to the anticipated date of commercial operation of

Generating Unit or Stage or Generating Station as a whole, as the case may be.

52.6 The Generating Company shall file a Petition for determination of provisional Tariff for new Generating Station based on capital expenditure incurred and projected to be incurred up to the date of commercial operation and additional capital expenditure incurred, duly certified by the statutory auditors:

Provided that the Petition shall contain details of underlying assumptions for the projected capital cost and additional capital cost, wherever applicable.

52.7 In the case of new projects, the Generating Company may be allowed provisional Tariff by the Commission from the anticipated date of commercial operation, based on the projected capital expenditure, subject to prudence check.

52.8 If the date of commercial operation is likely to be delayed beyond six months from the date of issue of the order approving the provisional Tariff, the Generating Company may submit a Petition for seeking extension of the validity of the applicability of the provisional Tariff, giving details of the present status of completion and justification for the delay in project completion, which may be considered by the Commission after necessary prudence check.

52.9 The Generating Company shall file the Petition for determination of final Tariff for new Generating Station within six months from the date of commercial operation of Generating Unit or Stage or Generating Station as a whole, as the case may be, based on the audited capital expenditure and capitalisation as on the date of commercial operation:

Provided that in case of more than one Unit in the Generating Station, such Petition shall be filed for each Unit as and when such Unit achieves COD and without waiting for the COD of the entire Station.

52.10 The final Tariff determination for the new Generating Station shall be done by the Commission based on prudence check of the audited capital expenditure and capitalisation as on the date of commercial operation.

52.11 Where the actual Capital Cost incurred on year to year basis is less than the Capital Cost approved for determination of provisional Tariff by the Commission, by five percent or more, the Generating Company shall refund to the Beneficiaries the excess Tariff realised corresponding to excess Capital Cost, along with interest at the Bank rate.

52.12 Where the actual Capital Cost incurred on year to year basis is more than the Capital Cost approved for determination of provisional Tariff by the Commission, by five percent or more, the Generating Company shall, subject to the approval of the Commission, recover from the Beneficiaries the shortfall in Tariff corresponding to such increase in Capital Cost, along with interest at the Bank rate.

52.13 A Generating Company with integrated mine(s) shall file a Petition for determination of input price of coal or lignite from the integrated mine(s) not later than 60 days from the date of commercial operation of the integrated mine(s):

Provided that the Generating Company having integrated mine(s) shall file Petition before the Commission for determination of the input price of coal or lignite from the integrated mine(s) containing the details of expenditure incurred and projected to be incurred duly certified by the Auditor, in accordance with the Formats that may be specified by the Commission.

52.14 In relation to multi-purpose hydroelectric Projects with irrigation, flood control and power components, the capital cost chargeable to the power component of the Project only shall be considered for determination of Tariff.

53 Capital Investment Plan

53.1 Generating company shall submit a detailed capital investment plan, financing plan and physical targets for each year of the Control Period for capacity growth, replacement of assets, renovation and/ modernization, meeting the environment norms, etc., to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period:

Provided that the Capital Investment Plan shall be submitted for each year of the Control Period as specified in Chapter 3 of these Regulations.

53.2 Capital Investment Plan shall be a least cost plan for undertaking investments and shall cover all capital expenditure projects of a value as specified in Guidelines for in-principle clearance of proposed investment schemes as provided in Schedule 3 of these Regulations and shall be in such form as may be stipulated.

53.3 Capital Investment Plan shall be accompanied by such information, particulars and documents as may be required showing the need for the proposed investments, alternatives considered, cost/benefit analysis and other aspects that may have a bearing on the energy charges and capacity charges of the Generating Station.

53.4 Generating Station or a Unit thereof, of any Generating Company or Distribution Licensee may undertake Renovation and Modernisation for the purpose of extension of life beyond the useful life as provided under Regulation 28.3 of these regulations:

53.5 Generating company or the licensee, as the case may be, shall submit, along with the Petition for determination of Aggregate Revenue Requirement on each year of the control period, details showing the progress of capital expenditure projects, together with such other information, particulars or documents as the Commission may require to assess such progress.

53.6 Generating company or the licensee, as the case may be, shall be required to ensure that the procurement of the assets have been undertaken in a competitive and transparent manner. Further the assets so capitalized as a part of the approved capital investment plan under these Regulations should necessarily be geo-tagged and properly recorded in Fixed Asset Register (FAR) for allowance of the capitalization of the same by the Commission:

Provided that regarding the Assets already capitalized as on April 01, 2026, the Generating company shall prepare and submit to the Commission a time-bound plan to undertake the geo-tagging in phased manner, preferably within the Control Period, along with the MYT Petition:

Provided further that the Generating company must provide access of the details of geo-tagging to the Commission for online monitoring.

54 Fuel Utilisation Plan

54.1 The Generating Company shall prepare and submit Fuel Utilisation Plan for the Control Period commencing on April 1, 2026, along with the Petition for determination of Tariff for the Control Period from April 1, 2026 to March 31, 2031, in accordance with Chapter-3 of these Regulations, to the Commission for approval.

54.2 The Fuel Utilisation Plan should ensure that fuel quantum is allocated to different generating Stations/Units in accordance with the merit order of different generation Stations/Units in terms of variable cost:

Provided that the fuel allocation should be such that, subject to system and other constraints, the least cost generating Stations/Units are operated at maximum availability and other generating Stations/Units are operated at maximum availability thereafter in the ascending order of variable cost.

54.3 The Fuel Utilisation Plan shall comprise the following:

a) Forecast of fuel requirement for each unit/station;

b) Details of contracted source, annual contracted quantity, estimated availability from contracted sources and resultant shortage of fuel, if any, for each unit/station;

c) Use of optimum mix of fuel;

d) Alternate arrangement for meeting shortage of fuel along with impact on variable cost of unit/station;

e) Plan for swapping of fuel source for optimising the cost, if any, along with detailed justification and cost savings;

f) Net cost savings in variable cost of each unit, if any, after optimum utilisation of Fuel:

Provided that the forecast or estimates for the Control Period from FY 2026-27 to FY 2030-31 shall be prepared for each month over the Control Period:

Provided further that Fuel Utilisation Plan shall be prepared based on past data and reasonable assumptions for future.

54.4 The beneficiary/ies may file comments/suggestions on such Plan during proceedings of Tariff Petition as per Regulation 14 of these Regulation.

54.5 The Commission shall approve the Fuel Utilisation Plan and rationalise the variable cost of generation for Generating Unit/Station based on such Plan and suggestions and comments received from the beneficiary/ies for the Control Period as part of its Order on the MYT Petition.

54.6 In case of part or full use of alternative source of fuel supply by coal based thermal generating stations other than as approved in the Fuel Utilization Plan on account of shortage of fuel or optimization of economic operation through blending, the use of alternative source of fuel supply shall be permitted to generating station:

Provided that in such case, prior permission from beneficiaries shall not be a precondition, unless otherwise agreed specifically in the power purchase agreement:

Provided also that where the energy charge rate based on weighted average price of fuel upon use of alternative source of fuel supply exceeds 30% of base energy charge rate as approved by the Commission in the Tariff Order for that year or exceeds 20% of energy charge rate of the previous month, whichever is lower shall be considered, and in that event, prior consultation with beneficiary shall be made at least three days in advance.

54.7 A Generating Company shall maintain data of actual performance of Unit/Station wise Fuel Utilisation vis-à-vis Fuel Utilisation plan approved by the Commission, along with justification for variation between approved and actual fuel utilisation plan and, shall put up such data within fifteen days from the end of each month, on the internet website of the Generating Company.

54.8 At the time of truing up of respective year, the Commission shall scrutinise the implementation of actual Fuel Utilisation Plan vis-à-vis approved plan, deviations, if any, and justification submitted by a Generating Company thereon and may disallow the variable cost of generation on account of operational inefficiencies in utilisation of fuel.

55 Components of Tariff

55.1 The Tariff for sale of electricity from a thermal power Generating Station shall comprise two parts, namely, capacity charge (for recovery of Annual Fixed Cost consisting of the components as specified in Regulation 56 of these regulations) and Energy Charge (for recovery of primary and secondary fuel cost and cost of limestone and any other reagent, where applicable as specified in Regulation ….. of these regulations).

55.2 The Supplementary tariff consisting of supplementary capacity charges and supplementary energy charges, on account of the implementation of revised emission standards in existing generating stations or new generating stations, as the case may be, shall be determined by the Commission separately.

55.3 The Tariff for sale of electricity from a hydro Generating Station shall comprise two parts, namely, Capacity Charge and Energy Charge to be derived in the manner as specified in regulation…….. of these regulations, as may be applicable, for recovery of the Annual Fixed Cost consisting of components referred in Regulation 56 of these regulations.

56 Annual Fixed Cost

56.1 The Annual Fixed Cost shall comprise the following components:

Operation & Maintenance Expenses;
Depreciation;
Interest on Loan Capital;
Interest on Working Capital;
Return on Equity Capital;
Contribution to reserve for Unforeseen Exigency, if any;
vii) Contribution to Development fund, if any;

minus:

viii) Non-Tariff Income;
ix) Income from other business and Incidental Services, to the extent specified in these regulations:

Provided that Operation & Maintenance Expenses, Depreciation, Interest on Loan Capital, Interest on Working Capital, Return on Equity, Non-tariff income and income from other business and incidental service shall be allowed, in accordance with the provisions specified in Chapter-4 of these Regulations:

Provided further that contribution to reserve for Unforeseen Exigency and Development fund to be allowed by the Commission after prudence analysis of the proposal subject to the provisions of these regulation:

Provided further that Special Allowance in lieu of R&M, if opted in accordance with the provisions of the Regulation 28.5 of these regulations, shall be recovered separately and shall not be considered for computation of working capital:

Provided also that, where a generating station has a dedicated transmission line, the ARR of the dedicated transmission line shall be determined similar to a transmission licensee and shall be added with Annual Fixed Charge of the generating station.

Provided also that prior period income/expenses shall be allowed by the Commission at the time of Truing-up based on audited accounts, on a case-to-case basis, if the income/expenses in that prior period have been allowed on actual basis, subject to prudence check:

Provided also that all penalties and compensation payable by the Generating Company to any party for failure to comply with any directions or for damages, as a consequence of the orders of the Commission, Courts, etc., shall not be allowed to recover through the Aggregate Revenue Requirement:

Provided also that the Generating Company shall maintain separate details of such penalties and compensation paid or payable by the Generating Company, if any, and shall submit them to the Commission along with its Petition.

57 Sale of Infirm Power

57.1 The tariff for sale of infirm power from a thermal generating station to the Distribution Licensee shall be equivalent to the actual fuel cost, including the secondary fuel cost, as the case may be, incurred during that period subject to prudence check.

Provided that any revenue earned by the Generating Company from supply of Infirm Power after accounting for the fuel cost shall be used for reduction in Capital Cost and shall not be treated as revenue.

58 Operational Norms for Generating Stations

58.1 The operating norms pertaining to the years 2026 - 27 to 2030 – 31, on the basis of which the annual revenue requirement of any generating station or unit thereof will be determined, have been laid down in Schedule-5 of these Regulations. For subsequent years the Commission shall notify the norms through suitable amendment of Schedule-5, as and when required:

Provided further that, in case of any Renovation & Modernization or Life Extension Programme of any existing generating station, the operating norms under Schedule -5 will be modified on the basis of submitted document(s) at the stage of investment approval.

59 Computation and Payment of Capacity Charges for Thermal Generating Stations:

A. Capacity Charges

59.1 The fixed cost of a thermal generating station shall be computed on annual basis based on the norms specified under these Regulations and recovered on monthly basis under Capacity Charge. The total Capacity Charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share or allocation in the capacity of the generating station. The Capacity Charge shall be recovered in two parts, viz, Capacity Charge for Peak Hours of the month and Capacity Charge for Off-Peak Hours of the month as follows:

59.2 The Capacity Charge payable to a thermal generating station for a calendar month shall be calculated in accordance with the following formulae:

Capacity Charge for the Month (CC_n) = Capacity Charge for Peak Hours of the Month (CC_{pn}) + Capacity Charge for Off-Peak Hours of the Month (CC_{opn})

Where,

Capacity Charge for Peak Hours of the Month

CC_{p1} =	[(0.20 x AFC) x (1/12) x ($PAFM_{p1}/NAPAF$) subject to ceiling of {(0.20 x AFC) x (1/12)}]
CC_{p2} =	[(0.20 x AFC) x (1/6) x ($PAFM_{p2}/NAPAF$) subject to ceiling of {(0.20 x AFC) x (1/6)}] – CC_{p1}
CC_{p3} =	[(0.20 x AFC) x (1/4) x ($PAFM_{p3}/NAPAF$) subject to ceiling of {(0.20 x AFC) x (1/4)}] – (CC_{p1} + CC_{p2})
CC_{p4} =	[(0.20 x AFC) x (1/3) x ($PAFM_{p4}/NAPAF$) subject to ceiling of {(0.20 x AFC) x (1/3)}] – (CC_{p1} + CC_{p2} +CC_{p3})
CC_{p5} =	[(0.20 x AFC) x (5/12) x ($PAFM_{p5}/NAPAF$) subject to ceiling of {(0.20 x AFC) x (5/12)}] – (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4})
CC_{p6} =	[(0.20 x AFC) x (1/2) x ($PAFM_{p6}/NAPAF$) subject to ceiling of {(0.20 x AFC) x (1/2)}] – (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} +CC_{p5})
CC_{p7} =	[(0.20 x AFC) x (7/12) x ($PAFM_{p7}/NAPAF$) subject to ceiling of {(0.20 x AFC) x (7/12)}] – (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6})
CC_{p8} =	[(0.20 x AFC) x (2/3) x ($PAFM_{p8}/NAPAF$) subject to ceiling of {(0.20 x AFC) x (2/3)}] – (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6} + CC_{p7})
CC_{p9} =	[(0.20 x AFC) x (3/4) x ($PAFM_{p9}/NAPAF$) subject to ceiling of {(0.20 x AFC) x (3/4)}] – (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6} + CC_{p7} + CC_{p8})
CC_{p10} =	[(0.20 x AFC) x (5/6) x ($PAFM_{p10}/NAPAF$) subject to ceiling of {(0.20 x AFC) x (5/6)}] – (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6} + CC_{p7} + CC_{p8} + CC_{p9})
CC_{p11} =	[(0.20 x AFC) x (11/12) x ($PAFM_{p11}/NAPAF$) subject to ceiling of {(0.20 x AFC) x (11/12)}] – (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6} + CC_{p7} + CC_{p8} + CC_{p9} + CC_{P10})
CC_{p12} =	[(0.20 x AFC) x ($PAFM_{p12}/NAPAF$) subject to ceiling of {(0.20 x AFC)}] – (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6} + CC_{p7} + CC_{p8} + CC_{p9} + CC_{P10} + CC_{p11})

Capacity Charge for Off-Peak Hours of the Month

CC_{op1} =	[(0.80 x AFC) x (1/12) x ($PAFM_{op1}/NAPAF$) subject to ceiling of {(0.80 x AFC) x (1/12)}]
CC_{op2} =	[(0.80 x AFC) x (1/6) x ($PAFM_{op2}/NAPAF$) subject to ceiling of {(0.80 x AFC) x (1/6)}] – CC_{op1}
CC_{op3} =	[(0.80 x AFC) x (1/4) x ($PAFM_{op3}/NAPAF$) subject to ceiling of {(0.80 x AFC) x (1/4)}] – (CC_{op1} + CC_{op2})
CC_{op4} =	[(0.80 x AFC) x (1/3) x ($PAFM_{op4}/NAPAF$) subject to ceiling of {(0.80 x AFC) x (1/3)}] – (CC_{op1} + CC_{op2} +CC_{op3})
CC_{op5} =	[(0.80 x AFC) x (5/12) x ($PAFM_{op5}/NAPAF$) subject to ceiling of {(0.80 x AFC) x (5/12)}] – (CC_{op1} + CC_{op2} + CC_{op3} + CC_{op4})
CC_{op6} =	[(0.80 x AFC) x (1/2) x ($PAFM_{op6}/NAPAF$) subject to ceiling of {(0.80 x AFC) x (1/2)}] – (CC_{op1} +CC_{op2} +CC_{op3} + CC_{op4} +CC_{op5})
CC_{op7} =	[(0.80 x AFC) x (7/12) x ($PAFM_{op7}/NAPAF$) subject to ceiling of {(0.80 x AFC) x (7/12)}] – (CC_{op1} + CC_{op2} + CC_{op3} + CC_{op4} + CC_{op5} + CC_{op6})

CC_{op8} =	[(0.80 x AFC) x (2/3) x ($PAFM_{op8}/NAPAF$) subject to ceiling of {(0.80 x AFC) x (2/3)}] – (CC_{op1} + CC_{op2} + CC_{op3} + CC_{op4} + CC_{op5} + CC_{op6} + CC_{op7})
CC_{op9} =	[(0.80 x AFC) x (3/4) x ($PAFM_{op9}/NAPAF$) subject to ceiling of {(0.80 x AFC) x (3/4)}] – (CC_{op1} + CC_{op2} + CC_{op3} + CC_{op4} + CC_{op5} + CC_{op6} + CC_{op7} + CC_{op8})
CC_{op10} =	[(0.80 x AFC) x (5/6) x ($PAFM_{op10}/NAPAF$) subject to ceiling of {(0.80 x AFC) x (5/6)}] – (CC_{op1} + CC_{op2} + CC_{op3} + CC_{op4} + CC_{op5} + CC_{op6} + CC_{op7} + CC_{op8} + CC_{op9})
CC_{op11} =	[(0.80 x AFC) x (11/12) x ($PAFM_{op11}/NAPAF$) subject to ceiling of {(0.80 x AFC) x (11/12)}] – (CC_{op1} + CC_{op2} + CC_{op3} + CC_{op4} + CC_{op5} + CC_{op6} + CC_{op7} + CC_{op8} + CC_{op9} + CC_{oP10})
CC_{op12} =	[(0.80 x AFC) x ($PAFM_{op12}/NAPAF$) subject to ceiling of {(0.80 x AFC)}] – (CC_{op1} + CC_{op2} + CC_{op3} + CC_{op4} + CC_{op5} + CC_{op6} + CC_{op7} + CC_{op8} + CC_{op9} + CC_{oP10} + CC_{op11})

Where,
CC_n = Capacity Charge for the n^{th} Month;
CC_{pn} = Capacity Charge for the Peak Hours of n^{th} Month;
CC_{opn} = Capacity Charge for the Off-Peak of n_{th} Month;
AFC = Annual Fixed Cost;
$PAFM_{pn}$ = Plant Availability Factor achieved during Peak Hours upto the end of nth Month;
$PAFM_{opn}$ = Plant Availability Factor achieved during Off-Peak Hours upto the end of nth Month;
NAPAF = Normative Annual Plant Availability Factor.

Provided that in case generating station or unit thereof is under shutdown due to Renovation and Modernization or installation of Emission Control System (ECS), as the case may be, the generating company shall be allowed to recover O&M expenses and interest on loan only.

Provided further that the Generating Company should plan interconnection of ECS with Generating Station during annual overhaul:

59.3 Normative Plant Availability Factor for “Peak” and “Off-Peak” Hours in a month shall be the NAPAF specified in Schedule-5 of these Regulations. The number of hours of “Peak” and “Off-Peak” periods during a day shall be four and twenty respectively. Hours of Peak and Off-Peak periods during a day shall be declared by SLDC at least a week in advance:

Provided that the SLDC, after duly considering the comments of the concerned stakeholders, shall declare Peak Hours in such a way as to coincide with the Peak Hours of the State.

59.4 The shortfall in recovery of Capacity Charge for cumulative Off-Peak Hours derived based on NAPAF shall be allowed to be off-set by over-achievement of PAF, if any, and consequent notional over-recovery of Capacity Charge for cumulative Peak Hours:

Provided that the shortfall in recovery of Capacity Charge for cumulative Peak Hours derived based on NAPAF, shall not be allowed to be off-set by over-achievement of PAF, if any, and consequent notional over-recovery of Capacity Charge for cumulative Off-Peak Hours:

Provided also that full Capacity Charges shall be recoverable at target availability specified in Schedule-5 of these Regulations, and recovery of Capacity Charges below the level of Target Availability shall be on pro-rata basis, irrespective of the reasons for the lower Availability, and no part of the Capacity Charges shall be recoverable except to the extent of Availability:

Provided that at zero availability, no Capacity Charges shall be payable.

59.5 The Plant Availability Factor for a Month (PAFM) shall be computed as per the following formula:

$$\text{PAFM} = 10000 \text{ x} \sum_{i=0}^{N} \frac{DCi}{\{N\ x\ IC\ x\ (100 - AUXn - AUXen)\}} \%$$

Where,

AUXn = Normative auxiliary energy consumption as a percentage of gross energy generation;

AUXen = Normative auxiliary energy consumption for emission control system as a percentage of gross energy generation, wherever applicable;

DCi = Average Declared capacity (in ex-bus MW) for the ith day of the period, i.e. month or year, as the case may be, as certified by the SLDC after the day is over;

IC = Installed capacity (in MW) of the complete generating station;

N = Number of days during the period.

59.6 In addition to the capacity charge, an incentive shall be payable to a generating station or unit thereof @ 75 paise/ kWh for ex-bus scheduled energy during Peak Hours and @ 55 paise/ kWh for ex-bus scheduled energy during Off-Peak Hours corresponding to scheduled generation in excess of ex-bus energy corresponding to Target Plant Load Factor (TPLF) achieved on a cumulative basis:

Provided that for this purpose of above incentive TPLF shall be considered same as the normative PAF of the respective power plant specified in Schedule-5 of these regulations.

B. Supplementary Capacity Charge:

59.7 Supplementary capacity charges shall be derived on the basis of the Annual Fixed Cost for emission control system (AFCe). The Annual Fixed Cost for the emission control system shall consist of the components as listed in Sub-clauses (i) to (vii) of Regulation 56 of these regulations.

59.8 The fixed cost of the emission control system shall be computed on an annual basis based on the norms specified under these regulations and recovered on a monthly basis under a supplementary capacity charge. The total supplementary capacity charge is payable for a generating station shall be shared by its beneficiaries as per their respective percentage share or allocation in the capacity of the generating station.

59.9 The Supplementary Capacity Charge payable to a coal or lignite generating station for a calendar month shall be calculated in accordance with the following formulae:

SCC_1 =	[(AFC_e) x (1/12) x ($PAFM_1/NAPAF$) subject to ceiling of {(AFC_e) x (1/12)}]
SCC_2 =	[(AFC_e) x (1/6) x ($PAFM_2/NAPAF$) subject to ceiling of {(AFC_e) x (1/6)}] – SCC_1
SCC_3 =	[(AFC_e) x (1/4) x ($PAFM_3/NAPAF$) subject to ceiling of {(AFC_e) x (1/4)}] – (SCC_1 + SCC_2)
SCC_4 =	[(AFC_e) x (1/3) x ($PAFM_4/NAPAF$) subject to ceiling of {(AFC_e) x (1/3)}] – (SCC_1 + SCC_2 + SCC_3)
SCC_5 =	[(AFC_e) x (5/12) x ($PAFM_5/NAPAF$) subject to ceiling of {(AFC_e) x (5/12)}] – (SCC_1 + SCC_2 + SCC_3 + SCC_4)
SCC_6 =	[(AFC_e) x (1/2) x ($PAFM_6/NAPAF$) subject to ceiling of {(AFC_e) x (1/2)}] – (SCC_1 + SCC_2 + SCC_3 + SCC_4 + SCC_5)
SCC_7 =	[(AFC_e) x (7/12) x ($PAFM_7/NAPAF$) subject to ceiling of {(AFC_e) x (7/12)}] – (SCC_1 + SCC_2 + SCC_3 + SCC_4 + SCC_5 + SCC_6)
SCC_8 =	[(AFC_e) x (2/3) x ($PAFM_8/NAPAF$) subject to ceiling of {(AFC_e) x (2/3)}] – (SCC_1 + SCC_2 + SCC_3 + SCC_4 + SCC_5 + SCC_6 + SCC_7)

SCC_9 =	[(AFC_e) x (3/4) x ($PAFM_9/NAPAF$) subject to ceiling of {(AFC_e) x (3/4)}] – ($SCC_1 + SCC_2 + SCC_3 + SCC_4 + SCC_5 + SCC_6 + SCC_7 + SCC_8$)
SCC_{10} =	[(AFC_e) x (5/6) x ($PAFM_{10}/NAPAF$) subject to ceiling of {(AFC_e) x (5/6)}] – ($SCC_1 + SCC_2 + SCC_3 + SCC_4 + SCC_5 + SCC_6 + SCC_7 + SCC_8 + SCC_9$)
SCC_{11} =	[(AFC_e) x (11/12) x ($PAFM_{11}/NAPAF$) subject to ceiling of {(AFC_e) x (11/12)}] – ($SCC_1 + SCC_2 + SCC_3 + SCC_4 + SCC_5 + SCC_6 + SCC_7 + SCC_8 + SCC_9 + SCC_{10}$)
SCC_{12} =	[(AFC_e) x ($PAFM_{12}/NAPAF$) subject to ceiling of {(AFC_e)}] – ($SCC_1 + SCC_2 + SCC_3 + SCC_4 + SCC_5 + SCC_6 + SCC_7 + SCC_8 + SCC_9 + SCC_{10} + SCC_{11}$)

Where,
SCC_n = Supplementary Capacity Charge for the nth Month;
AFC_e = Annual Fixed Cost of the emission control system;
$PAFM_n$ = Plant Availability Factor achieved up to the end of nth Month;
NAPAF = Normative Annual Plant Availability Factor

Provided that in case of the generating station or unit thereof under shutdown due to Renovation and Modernisation, the generating company shall be allowed to recover O&M expenses and interest on the loan in respect of the emission control system only.

59.10 Normative Plant Availability Factor for a month for the purpose of Supplementary Capacity Charge shall be the NAPF specified in Schedule-5 of these regulations. The PAFM shall be worked out in accordance with Regulation 59.5 of these regulations.

60 Computation and Payment of Energy Charges for Thermal Generating Stations:

60.1 The Energy Charge of the thermal generating station shall be derived on the basis of the landed fuel cost of the generating station and shall comprise the landed cost of primary fuel, secondary fuel oil consumption and cost of limestone or any other reagents, as applicable:

Provided further that the supplementary energy charges, if any, on account of meeting the revised emission standards in case of a thermal generating station shall be determined separately by the Commission as per Regulation 60.8 of these regulations

60.2 The landed fuel cost of primary fuel for any month shall consist of the base price or input price of fuel corresponding to the grade and quality of fuel and shall be inclusive of statutory charges as applicable, washery charges, transportation cost by rail or road or any other means and loading, unloading and handling charges. The landed cost for the purpose of computation of energy charge shall be arrived at after considering normative transit and handling losses as specified in Regulation 60.4 of these regulations:

Provided that procurement of fuel at a price other than Government notified prices may be considered if it is based on competitive bidding through a transparent process;

Provided further that the landed fuel cost of primary fuel shall be worked out based on the actual bill paid by the generating company, including any adjustment on account of quantity and quality;

Provided also that any compensation or penalty paid by the Generating Station to fuel supplier or transporter or any agency shall not be allowed under fuel cost:

Provided also that any refund of taxes and duties duties along with any amount received on account of penalties from the fuel supplier shall be adjusted in fuel cost:

Provided also that in the case of coal-based thermal generating station, the Gross Calorific Value shall be measured by third party sampling, and the expenses towards the third-party sampling facility shall be reimbursed by the beneficiaries.

60.3 The input price of coal from the integrated mine(s) shall be determined by the Commission after commercial operation of the input mine in accordance with the provisions of Chapter-9 of these regulations:

Provided that after the date of commercial operation of the integrated mine(s) till the input price of coal is determined by the Commission under these Regulations, the generating company or licensee shall adopt the notified price of Coal India Limited commensurate with the grade of the coal from the integrated mine(s) or the estimated price available in the investment approval, whichever is lower, as the input price of coal for the generating station:

Provided further that, the difference between the input price of coal determined under these Regulations and the input price of coal so adopted prior to such determination, for the quantity of coal billed, shall be by refund or recovery of such excess or shortfall amount, as the case may be, with simple rate of interest as per the Bank rate.

60.4 Transit and handling Losses:

Transit and handling losses for coal or lignite based generating stations, as a percentage of quantity of coal or lignite dispatched by the coal or lignite supply company during the month shall be as given below:

(i) Pit head generating stations: 0.20%;
(ii) Non-pit head generating stations: 0.80%;

Provided that in case of pit head stations if coal or lignite is procured from sources other than the pit head mines which is transported to the station through rail, transit loss of 0.80% shall be applicable:

Provided further that in case of imported coal, the transit and handling losses shall be 0.20%, subject to terms of delivery.

60.5 Gross Calorific Value of Primary Fuel:

i) The gross calorific value for computation of energy charges as per Regulation 60.9 of these regulations shall be done in accordance with 'GCV as Received’;

ii) The measurement of GCV of domestic coal shall be done based on third party sampling through an agency to be appointed by the generating company or the licensee, as the case may be, in accordance with the guidelines, if any, issued by the Central Government and the generating company or licensee shall ensure recovery of compensation as per Fuel Supply Agreement(s) and pass on the benefits of the same to the beneficiaries of the generating station:

Provided that the maximum admissible variation between the ‘as billed’ GCV and ‘as received GCV’ for domestic coal shall be 300 kCal per kg:

Provided further that in the absence of third-party sampling, computation of the energy charges as per Regulation 60.9 of these Regulations shall be done in accordance with 'GCV as Billed’;

iii) In the case of an integrated coal mine, the GCV of coal received at the end use generating station shall be adjusted by 15 kCal/Kg from the GCV measured at the mine end for every 100 km distance beyond 200 Km, or actual whichever is lower, subject to the condition that such an adjustment in aggregate shall not exceed 300 kCal/kg:

Provided further that the Commission after carrying out a detailed study may rationalise the mechanism for arriving at the gross calorific value of domestic coal at the generating station by considering the various factors impacting the calorific value throughout entire value chain from the delivery of coal to receiving at the generating station.

iv) No loss in calorific value between ‘GCV as billed’ and ‘GCV as received' shall be admissible for generating stations procuring coal through import, through ‘e-auction’ and washed coal.

v) The generating company shall provide to the beneficiaries of the generating station the details in respect of GCV and price of fuel i.e. domestic coal, imported coal, e-auction coal, lignite, natural gas, RLNG, liquid fuel etc., as per the Form 15 prescribed at Annexure-I (Part I) to these regulations:

Provided that the additional details of the weighted average GCV of the primary fuel on a received basis used for generation during the period, the blending ratio of the imported coal with domestic coal, and the proportion of e-auction coal shall be provided, along with the bills of the respective month;

Provided further copies of the bills and details of parameters of GCV and price of fuel such as domestic coal, imported coal, e-auction coal, lignite, natural gas, RLNG, liquid fuel, details of blending ratio of the imported coal with domestic coal, the proportion of e-auction coal shall also be displayed on the website of the generating company.

60.6 Landed Cost of Reagent:

(i) Where specific reagents such as Limestone, Sodium Bi-Carbonate, Urea or Anhydrous Ammonia are used during the operation of an emission control system for meeting revised emission standards, the landed cost of such reagents shall be determined based on the normative consumption and the purchase price of the reagent through competitive bidding, applicable statutory charges and transportation cost.

(ii) The normative consumption of specific reagents for the various technologies installed for meeting revised emission standards shall be as specified in Schedule-5 of these regulations.

60.7 Energy Charges shall cover the primary and secondary fuel cost and shall be payable by every beneficiary for the total energy scheduled to be supplied to such beneficiary during the calendar month on an ex-power plant basis, at the energy charge rate of the month (with fuel price adjustment), as per the following formulae:

Energy Charges (INR) = (Energy Charge Rate in INR/kWh) x [Scheduled Energy (ex-bus) for the month in kWh]

60.8 The supplementary Energy Charges on account of Emission Control System shall cover the differential energy charge due to auxiliary energy consumption and cost of reagent consumption and shall be payable by every beneficiary for the total energy scheduled to be supplied to such beneficiary during the calendar month on an ex-power plant basis, at the supplementary energy charge rate of the month, as per the following formulae:

Supplementary Energy Charges (INR) = (Supplementary Energy Charge Rate in INR/kWh) x [Scheduled Energy (ex-bus) for the month in kWh]

60.9 Energy Charge Rate (ECR) and Supplementary Energy Charge Rate in INR/kWh on ex-power plant basis shall be computed up to three decimal places in accordance with the following formulae:

a) ECR for coal-based power stations:

$$ECR = [\{(SHR – SFC \times CVSF) \times LPPF / CVPF\} + (SFC \times LPSFi) + (LC \times LPL)] \times 100 / (100 – AUX_n)$$

b) Supplementary Energy Charge Rate for coal-based power stations:

$$\text{Supplementary ECR} = (\Delta ECR) + [(SRC \times LPR/ 10) / \{100 – (AUX_n + AUX_{en})\}]$$

Where,

AUX_n = Normative auxiliary energy consumption in percentage of gross energy generation;

AUX_{en} = Normative auxiliary energy consumption for emission control system in percentage of gross energy generation;

CVPF = Weighted Average Gross calorific value of coal considering GCV as per Regulation 60.5 of these regulations, in kCal per kg for coal base generating station less actual staking losses in calorific value of coal on account of variation during storage at generating station:

Provided that the actual stacking loss is subject to maximum value 120 kCal per kg:

Provided further that in case of blending of fuel from different sources, the weighted average Gross Calorific value of the primary fuel shall be arrived at in proportion to the blending ratio.

CVSF = Calorific value of secondary fuel, in kCal per ml;

ECR = Energy Charge rate, in INR per kWh sent out;

LC = Normative Limestone consumption;

LPL = Weighted average landed cost of limestone, in INR per kg;

LPPF = Weighted average landed cost of primary fuel, in INR per kg during the month. In case of blending of fuel from different sources, the weighted average landed fuel cost of primary fuel shall be arrived at in proportion to the blending ratio;

LPR = Weighted average landed price of reagent for the emission control system in Rs./kg

LPSFi = Weighted average landed cost of secondary fuel, in INR per ml during the month.

SFC = Normative secondary fuel oil consumption, in ml per kWh;

SHR = Gross Station Heat Rate, in kCal per kWh;

SRC = Specific reagent consumption on account of revised emission standards in g/kWh;

ΔECR = Difference between ECR with revised auxiliary energy consumption with emission control system equivalent to (AUXn + AUXen) and ECR with normative auxiliary energy consumption as specified in these regulations.

Provided also that in case of blending of fuel from different sources, the weighted average Gross Calorific Value of primary fuel shall be arrived in proportion to blending ratio:

Provided also that the Energy Charges, for the purpose of billing/Fuel Surcharge shall be worked out Station-wise/Unit-wise based on weighted average rate based on scheduled generation from each Unit.

Provided also that where biomass fuel is used for blending with coal, the landed cost of biomass fuel shall be worked out based on the delivered cost of biomass at the unloading point of the generating station, inclusive of taxes and duties as applicable:

Provided also that the energy charge rate of the blended fuel shall be worked out considering consumption of biomass based on blending ratio as specified by Authority or actual consumption of biomass, whichever is lower:

Provided also that the Generating Company may opt for higher blending ratio subject to techno-economic viability and the benefits in terms of lower tariff being entirely passed through to the beneficiaries, and loss, if any, being entirely borne by the Generating Company.

60.10 The Commission, through specific tariff orders to be issued for each generating station, shall approve the energy charge rate at the start of the tariff period. The energy charge rate so approved shall be the base energy charge rate for the first year of the tariff period. The base energy charge rate for subsequent years shall be the energy charge computed after escalating the base energy charge rate by escalation rates for payment purposes as notified by the CERC from time to time under competitive bidding guidelines:

Provided that the landed cost of primary fuel and secondary fuel for tariff determination shall be based on actual weighted average cost of primary fuel and secondary fuel of the three preceding months, and in the absence of landed costs for the three preceding months, latest procurement price of primary fuel and secondary fuel for the generating Station, preceding the first month for which the Tariff is to be determined for existing stations, and immediately preceding three months in case of new generating stations shall be taken into account:

60.11 The generating company or the licensee shall recover the energy charge on monthly basis as per the formulae specified in regulation 60.9 above considering the actual landed cost and Gross calorific value of the fuel, subject to the provisions of these Regulations:

Provided that in case of shortage of fuel or for any other reason, generating company may use alternative source of fuel supply that than admitted under the fuel utilization plan, subject to the provisions of regulation 54.6 of these Regulations:

In case of shortage of fuel supply, the beneficiary does not give its consent under regulation 54.6, the generating station may claim for notional declared capacity in terms of regulation 63 of these Regulations.

61 Computation and Payment of Capacity Charge and Energy Charges for Hydro Generating Stations:

61.1 The fixed cost of a Hydro Generating Station shall be computed on annual basis, based on norms specified under these Regulations, and recovered on monthly basis under Capacity Charge (inclusive of incentive) and Energy Charge, which shall be payable by the beneficiaries in proportion to their respective allocation in the saleable capacity of the Generating Station, i.e. in the capacity excluding the free power to home state:

61.2 The Capacity Charge (inclusive of incentive) payable to a Hydro Generating Station for a calendar month shall be:

$$AFC \times 0.5 \times NDM / NDY \times (PAFM / NAPAF) \text{ (in INR)}$$

Where,

AFC = Annual fixed cost specified for the year, in INR

NAPAF = Normative Annual Plant Availability Factor in percentage

NDM = Number of days in the month

NDY = Number of days in the year

PAFM = Plant availability factor achieved during the month, in Percentage

61.3 The PAFM shall be computed in accordance with the following formula:

$$PAFM = 10000 \text{ x} \sum_{i=0}^{N} \frac{DCi}{\{N \text{ x } IC \text{ x } (100 - AUX)\}} \%$$

Where,

AUX = Normative auxiliary energy consumption in percentage;

DCi = Declared capacity (in ex-bus MW) for the ith day of the month, which the station can deliver at least three (3) hours, as certified by the SLDC after the day is over;

IC = Installed capacity (in MW) of the complete generating station;

N = Number of days in the month

61.4 The Energy Charge shall be payable by every beneficiary for the total energy scheduled to be supplied to the beneficiary/ies, excluding free energy to home State, if any, during the calendar month, on ex-bus basis, at the computed Energy Charge Rate. Total Energy Charge payable to the Generating Company for a month shall be:

Energy Charges in INR = (Energy Charge Rate in INR / kWh) x {Scheduled Energy (ex-bus) for the month in kWh} x (100 – FEHS) / 100

61.5 Energy Charge Rate (ECR) in INR per kWh on ex-bus basis, for a Hydro Generating Station, shall be determined up to three decimal places based on the following formula:

ECR = AFC x 0.5 x 10 / {DE x (100 – AUX) x (100 – FEHS)}

Where,

DE = Annual Design Energy specified for the Hydro Generating Station, in kWh, subject to Regulation 61.7.

FEHS = Free energy for home State, in per cent

61.6 In case the saleable scheduled energy (ex-bus) of a hydro generating station during a year is less than the saleable design energy (ex-bus) for reasons beyond the control of the generating station, the generating station may directly recover the shortfall in energy charges in six equal interest-free monthly instalments after adjusting for DSM Energy in the immediately following year and shall be subject to truing up at the end of the tariff period

Provided that in case actual generation from a hydro generating station is less than the design energy for a continuous period of four years on account of hydrology factor, the generating station shall approach the Central Electricity Authority with relevant hydrology data for revision of design energy of the station.

61.7 Any shortfall in the energy charges on account of saleable scheduled energy (ex-bus) being less than the saleable design energy (ex-bus) during the previous control period, which was beyond the control of the generating station and which could not be recovered during the said tariff period shall be recovered in accordance with clause (7) of this Regulation

61.8 In case the energy charge rate (ECR) for a hydro generating station, computed as per Regulation 61.5 of these regulations exceeds one hundred and thirty paise per kWh, and the actual saleable energy in a year exceeds {DE x (100- AUX) x (100 - FEHS) /10000} MWh, the energy charge for the energy in excess of the above shall be billed at one hundred and thirty paise per kWh only.

61.9 In addition to the above, an incentive shall be payable to a Run of River Hydro generating station @ 50 paise/ kWh corresponding to the saleable scheduled energy during peak hours of the day in excess of average saleable scheduled energy during the day (24 hours).

62 Computation and Payment of Capacity Charge and Energy Charges for Pumped Storage Hydro Generating Stations:

62.1 The fixed cost of a pumped storage hydro generating station shall be computed on an annual basis, based on norms specified under these regulations, and recovered on a monthly basis as a capacity charge. The capacity charge shall be payable by the beneficiaries in proportion to their respective allocation in the saleable capacity of the generating station;

62.2 The capacity charge payable to a pumped storage hydro generating station for a calendar month shall be:

a) (AFC x NDM / NDY) (In INR), if actual Generation during the month is ≧ 75 % of the Pumping Energy consumed by the station during the month; or

b) {(AFC x NDM / NDY) x (Actual Generation during the month during peak hours/ 75% of the Pumping Energy consumed by the station during the month) (in INR)}, if actual Generation during the month is < 75 % of the Pumping Energy consumed by the station during the month.

Where,
AFC = Annual fixed cost specified for the year, in INR;
NDM = Number of days in the month;
NDY = Number of days in the year:

Provided that there would be adjustments at the end of the year based on actual generation and actual pumping energy consumed by the station during the year.

62.3 The energy charge shall be payable by every beneficiary for the total energy scheduled to be supplied to the beneficiary in excess of the design energy plus 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir, at a flat rate equal to the average energy charge rate of 20 paise per kWh, if any, during the calendar month, on ex power plant basis.

62.4 Energy charge payable to the generating company for a month shall be:

= 0.20 x {(Scheduled energy (ex-bus) for the month in kWh - Design Energy for the month (DEm)) + 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir of the month)}/ 100.

Where,
DEm = Design energy for the month specified for the hydro generating station, in MWh:

Provided that in case the Scheduled energy in a month is less than the Design Energy for the month plus 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir of the month, then the energy charges payable by the beneficiaries shall be zero:

Provided that if the energy for the pumping of water from lower reservoir to upper reservoir is arranged by the generating company, the charges for the pumping energy till the ex-Bus of the generating station shall be payable by the beneficiaries in proportion to their respective allocation in the saleable capacity of the generating station:

62.5 The generating company or licensee shall maintain the record of daily inflows of natural water into the upper elevation reservoir and the reservoir levels of the upper elevation reservoir and lower elevation reservoir on an hourly basis. The generator shall be required to maximize the peak hour supplies with the available water, including the natural flow of water. In case it is established that the generator is deliberately or otherwise, without any valid reason, not pumping water from a lower elevation reservoir to a higher elevation during off-peak periods or not generating power to its potential or wasting the natural flow of water, the capacity charges of the day shall not be payable by the beneficiary. For this purpose, outages of the unit(s)/station, including planned outages and forced outages up to 15% in a year, shall be construed as the valid reason for not pumping water from the lower elevation reservoir to the higher elevation during an off-peak period or not generating power using the energy of pumped water or natural flow of water:

Provided that the total capacity charges recovered during the year shall be adjusted on a pro-rata basis in the following manner in the event of total machine outages in a year exceeding 15%:

$$(ACC)adj = (ACC)\ R \times (100 - ATO)/85$$

Where,
(ACC)adj = Adjusted Annual Capacity Charges;
(ACC) R = Annual Capacity Charges recovered;
ATO = Total Outages in percentage for the year including forced and planned outages:

Provided further that the generating station shall be required to declare its machine availability daily on day ahead basis for all the time blocks of the day in line with the scheduling procedure of State Grid Code.

62.6 The SLDC shall finalise the schedules for the hydro generating stations and Pumped Storage Hydro Generating Stations, in consultation with the beneficiaries, for optimal utilization of all the energy declared to be available, which shall be scheduled for all beneficiaries in proportion to their respective allocations in the generating station.

63 Notional Declared Capacity:

63.1 In case of shortage of coal availability from the sources as per the approved Fuel Utilization plan and the beneficiary has not permitted to purchase coal from alternative source(s), the generating station shall declare 15 minutes time block-wise capacity for both the situations as mentioned below:

(i) Actual Declared Capacity taking into consideration existing actual shortage in coal supply and this is to be known as declared capacity; and

(ii) Notional Declared Capacity considering no shortage notionally in coal supply.

Provided that for the purpose of showing shortage in coal supply during the period of April to July and November to March of a year, the stock in the power plant shall be less than 2 days on the basis of average coal requirement per day and the claim of shortage will be verified by SLDC based on the coal stock related data provided by the generating station on the basis of submitted data as per regulation 63.2 of these regulations and daily coal consumptions and receipt to be provided in accordance with State Grid Code:

Provided further that for the purpose of showing shortage in coal supply during the period of August to October of a year, the stock in the power plant shall be less than 4 days on the basis of average coal requirement per day and the claim of shortage will be verified by SLDC based on the coal stock related data provided by the generating station on the basis of submitted data as per regulation 63.2 of these regulations and daily coal consumptions and receipt to be provided in accordance with State Grid Code:

Provided further that in case of any dispute, physical check by the beneficiaries in the presence of SLDC representative will be done in order to verify the stock position. In case of dispute SLDC's decision on coal-stock will be final for the purpose of capacity charge recovery:

Provided further that recovery of the Capacity Charge arising out of shortage in coal supply from linkage source will be considered if it is found that the licensee/ generating company has explored all the possibilities of acquiring coal through e- auction or import to compensate such coal shortage and for procurement of coal through such mechanism the rise in energy charge does not exceed the limit specified in Regulation 54.6 of these regulations.

63.2 For the purpose of determination of average coal requirement per day, as required under regulation 63.1, the annual coal requirement in MT as determined under last tariff order and the number of days in that year shall be considered. In this matter carpet coal shall not be considered for determining 'Coal Stock' in the coal yard of the generating station. SLDC shall initially collect the carpet coal stock position and base stock at the starting of the year. For this purpose the generating station shall also provide the quantity of daily coal consumption and receipt to the SLDC.

63.3 Notwithstanding anything contained contrary to this regulation, the extent of resultant affected availability due to shortage in supply of coal as provided in regulation 63.1 and used for part of capacity charge recovery commensurate with the resultant affected availability shall not be entitled to earning any incentive.

64 **Demonstration of declared capacity:**

64.1 The Generating Company may be required to demonstrate the actual declared capacity and notional declared capacity of its Generating Station as and when asked by the SLDC. In the event of the Generating Company failing to demonstrate the declared capacity, the Annual Fixed Charges due to the Generating Company shall be reduced as a measure of penalty:

Provided that SLDC shall clearly specify whether demonstration is required for actual declared capacity or notional declared capacity:

Provided further that SLDC shall mandatorily ask for at least one demonstration of notional declared capacity, when generating station has claimed for coal shortage:

Provided also that one demonstration shall be for a duration of 15 minutes time block against the Declared Capacity, where such demonstration period excludes the ramp-up and ramp down time:

64.2 The quantum of penalty for the first mis-declaration for any duration/block in a day shall be the charges corresponding to two days fixed charges. For the second mis-declaration, the penalty shall be equivalent to fixed charges for four days and for subsequent mis-declarations in the year, the penalty shall be multiplied in the geometrical progression till the recoverable monthly capacity charge becomes zero in that month. The penalty arising out of mis-declaration shall be recorded by SLDC as specified in the Balancing and Settlement Code.

64.3 During demonstration of Declared Capacity the actual injection will be treated as the revised schedule of injection for those 15 minutes time block and the period of ramp-up and ramp-down under which such demonstration takes place in accordance with prior intimation to all entities by SLDC about undertaking of such demonstration. The impact of such additional injection due to such demonstration will be distributed as additional drawal schedule among the purchaser of electricity of that generating station in proportion to their original drawal schedule or as per direction of SLDC where such additional generation can be scheduled for any licensee who has shortage of power or to the licensee (s) who has asked for such demonstration.

64.4 The Generating Company or the licensee, as the case may be, shall also provide on-line monitoring display arrangement of generation/sent-out of the generating stations along with dedicated voice communication at SLDC to meet the need of regulation 64.1 of these Regulations.

64.5 The operating logbooks of the Generating Station shall be available for scrutiny by the SLDC, and these books shall keep record of machine operation and maintenance. For hydro-generating stations, the logbook shall also have records of reservoir level and spill way gate operation.

65 Billing and Payment of Charges

65.1 The Billing and Payment of Capacity Charges, Energy Charges, Supplementary Capacity Charge, Supplementary Fuel Charge and Incentive for Thermal Generating Stations, and of Capacity Charges and Energy Charges for Hydro Generating Stations including Pumped Storage Plants, shall be done on a monthly basis.

66 Deviation Charges

66.1 Variations between actual net injection and scheduled net injection for the generating stations, and variations between actual net drawal and scheduled net drawal for the Beneficiary/ies shall be treated as their respective deviations, and charges for such deviations shall be governed by the West Bengal Electricity Regulatory Commission (Deviation Settlement Mechanism and Related matters) Regulations, 2021, as amended from time to time:

66.2 The Deviation Charges and any penalty or incentive, paid or earned by the Generating Company in accordance with the West Bengal Electricity Regulatory Commission (Deviation Settlement Mechanism and Related matters) Regulations, 2021, as amended from time to time, shall not be recoverable/adjusted from the beneficiary/ies through Tariff.

67 Sharing of CDM benefits

67.1 Any income by licensee or generating company from carbon trading or greenhouse emissions reduction programme or environmental pollution reduction programme, reduced by expenses relating to such activity, shall be used partially for the benefit of the consumer and licensee purchasing power from them by utilizing 30% of such income to reduce the ARR. However, in case of loss from such trading or programme, such loss shall not be allowed to be adjusted against aggregate revenue requirement.

68 Sharing of income from supplying power to any person other than the beneficiary:

68.1 Fifty percent of the income arising to the Generating Company from supplying unrequested surplus powers for its generating station to any person other than its beneficiary(ies), shall be shared among its beneficiary(ies) in the ratio of their contracted capacities in that generating station:

Provided that the actual cost of fuel related to such generation, limited to the normative fuel cost and the transmission and related costs are to be deducted from the revenue earned to arrive at the income for the purpose of this regulation:

Provided further that the generating station shall take consent from its beneficiary(ies) for sale of any surplus power in a manner as has been agreed in the Power Purchase Agreement or the manner specified or to be specified by the Commission from time to time.

68.2 The balance fifty percent of income shall first be used to meet the unrecovered capacity charge of the Generating station, if any, and the remaining amount shall be kept in the Development fund and to be maintained as per the regulation 46 of these Regulations.

68.3 However, in case of loss arising out of such activity, such loss shall not be allowed to be recovered against annual revenue requirement for determination of tariff and / or for sale to the distribution licensee under the purview the Commission.

69 Compensation in relation to operation on account of backing down

69.1 In case a Generating Station or Unit is instructed for backing down as per direction given by SLDC on account of grid security or due to the lower schedule given by the beneficiaries, the impact of the same on any of the operational parameters such as Gross Station Heat Rate, Auxiliary consumption and Secondary Fuel Oil Consumption, may be considered by the Commission on case to case basis at time of truing up, subject to prudence check.

CHAPTER – 6

TRANSMISSION

70 Applicability

70.1 The Regulations contained in this Chapter shall apply to the determination of Tariff for access and use of the Intra-State transmission system pursuant to a Bulk Power Transmission Agreement or other arrangement entered into with a Transmission System User, which is not covered under Regulation 69.3 dealing with the adoption of tariff through Tariff Based Competitive Bidding (TBCB) Route under Section 63 of the Act.

70.2 The Commission shall be guided by the Regulations contained in this Chapter in specifying the rates, charges, terms and conditions for use of intervening transmission facilities pursuant to an application made in this regard by a Licensee under the proviso to Section 36 of the Act.

70.3 All the new greenfield intra-State transmission systems costing above the Threshold Limit and meeting other conditions as laid out in Modalities of Tariff Regulations, shall be developed through Tariff Based Competitive Bidding (TBCB) in accordance with the guidelines issued by the Central Government under Section 63 of the Act.

71 Petition for determination of Transmission Tariff

71.1 A Transmission Licensee shall file a Petition for determination of Tariff for access and use of its Transmission network by the Transmission System Users in accordance with the provisions of Chapter-2 of these Regulations. The Tariff petition includes Capital investment Plan, proposal for Aggregate Revenue Requirement, Expected Revenue from Charges at existing tariff and year-wise proposed transmission charges in such manner and formats as specified in these Regulations

71.2 The existing Transmission licensee shall continue to bill the Transmission System Users (TSU) at the Tariff approved by the Commission and applicable as on March 31, 2026 for the period starting from April 1, 2026 till approval of Tariff by the Commission in accordance with these Regulations.

71.3 Any new Transmission Licensee shall file the Petition for determination of provisional Tariff, six months prior to the anticipated date of commercial operation of the transmission assets, based on capital expenditure incurred or projected to be incurred upto the date of commercial operation and additional capital expenditure, duly certified by the auditor:

Provided that the Petition shall contain details of underlying assumptions for the projected capital cost and additional capital cost, wherever applicable.

71.4 The new Transmission Licensee may be allowed provisional Tariff by the Commission from the anticipated date of commercial operation, based on the projected capital expenditure, subject to prudence check.

71.5 If the date of commercial operation is likely to be delayed beyond six months from the date of issue of the order approving the provisional Tariff, the Transmission Licensee may submit a Petition for seeking extension of the validity of the applicability of the provisional Tariff, giving details of the present status of completion and justification for the delay in project completion, which may be considered by the Commission after necessary prudence check.

71.6 The new Transmission Licensee shall file the Petition for determination of final Tariff within six months from the date of commercial operation, based on the audited capital expenditure and capitalisation as on the date of commercial operation.

71.7 The final Tariff determination for the new Transmission Licensee shall be done by the Commission based on prudence check of the audited capital expenditure and capitalisation as on the date of commercial operation.

71.8 Where the actual Capital Cost incurred on year to year basis is less than the Capital Cost approved for determination of provisional Tariff by the Commission, by five percent or more, the Transmission Licensee shall refund to the Transmission system users, the excess Tariff realised corresponding to excess Capital Cost, along with interest at the Bank rate.

71.9 Where the actual Capital Cost incurred on year to year basis is more than the Capital Cost approved for determination of provisional Tariff by the Commission, by five percent or more, the Transmission Licensee shall, subject to the approval of the Commission, recover from the Transmission System Users the shortfall in Tariff corresponding to such decrease in Capital Cost along with interest at the Bank rate.

72 Capital Investment Plan

72.1 Transmission Licensee shall submit a detailed capital investment plan, financing plan, physical targets and capitalization schedule for each year of the Control Period for strengthening and augmentation of Intra-

State Transmission network, meeting the requirement of load growth, improvement in quality of supply, reliability, metering, congestion management, integration of renewable energy sources, etc., to the Commission for approval, as a part of the Multi-Year Aggregate Revenue Requirement for the entire Control Period:

72.2 Capital Investment Plan shall be a least cost plan for undertaking investments and shall cover all capital expenditure projects of a value as specified in Guidelines for in- principle approval of proposed investment schemes as provided in Schedule-3 of these Regulations or such other amount as may be stipulated by the Commission from time to time, and shall be in such form as may be stipulated.

72.3 Capital Investment Plan shall be accompanied by such information, particulars and documents as may be required including but not limited to the information such as number of bays, name, configuration and location of grid substations, substation capacity (MVA), transmission line length (ckt-km) showing the need for the proposed investments, alternatives considered, cost/benefit analysis and other aspects that may have a bearing on the transmission charges.

72.4 Capital Investment Plan of the Transmission Licensee shall be consistent with the rolling basis State Transmission System Plan prepared by STU in accordance with the Modalities of Tariff Regulations.

72.5 Transmission Licensee shall be required to ensure that the procurement of the assets have been undertaken in a competitive and transparent manner. Further the assets so capitalized as a part of the approved capital investment plan under these Regulations should necessarily be geo-tagged and properly recorded in Fixed Asset Register (FAR) for allowance of the capitalization of the same by the Commission:

Provided that regarding the Assets already capitalized as on April 01, 2026, the Transmission Licensee shall prepare and submit to the Commission a time-bound plan to undertake the geo-tagging in phased manner, preferably within the Control Period, along with the MYT Petition:

Provided further that the Transmission Licensee must provide access of the details of geo-tagging to the Commission for online monitoring.

72.6 The Commission shall consider the Capital Investment Plan along with the Multi-Year Aggregate Revenue Requirement for the entire Control Period submitted by the Transmission Licensee taking into consideration the prudence of the proposed expenditure and estimated impact on Transmission Charges and retail tariff and also taking into consideration the factors outlined under regulations 25.10, 25.11 and 26 of these Regulations.

72.7 Transmission Licensee shall submit, along with the Petition for true-up on each year of the control period, details showing the progress of capital expenditure projects, together with such other information, particulars or documents as the Commission may require to assess such progress.

73 Components of Tariff

73.1 The transmission charges for access to and use of the intra-State transmission system shall comprise any of the following components or a combination of the following components:

a) annual transmission charges;
b) per unit charges for energy transmitted;
c) reactive energy charges.

73.2 Annual Transmission Charges for each financial year of the Control Period shall provide for the recovery of the Aggregate Revenue Requirement of Transmission Licensee for the respective financial year of the Control Period, as reduced by the amount of Non-Tariff Income, income from other business and short-term transmission charges of the previous year, as approved by the Commission:

Provided that in case of competitively awarded transmission system projects in pursuance of Section 63 of the Act and in accordance with guidelines for competitive bidding for transmission, the annual transmission charges shall be as per the annual Transmission Service Charges (TSC) quoted by such competitively awarded transmission projects.

74 Annual Transmission Charge

74.1 The Annual Transmission Charges for each Year of the Control Period shall provide for the recovery of the Aggregate Revenue Requirement of the Transmission Licensee for the respective Year of the Control Period, as approved by the Commission and comprising the following components:

a) Operation and maintenance expenses;
b) Depreciation;

c) Interest on Loan Capital;
d) Return on Equity;
e) Interest on working capital and deposits from transmission system Users;
f) Contribution to reserve for Unforeseen Exigency, if any;
g) Contribution to Development fund, if any

minus:

h) Non-Tariff Income;
i) Revenue from short-term transmission charges projected on the basis of latest audited figures; and
j) Income from Other Business, to the extent specified in these Regulations.

Provided that Operation & Maintenance Expenses, Depreciation, Interest on Loan Capital, Interest on Working Capital and deposit, Return on Equity, Non-tariff income and income from other business and incidental service shall be allowed, in accordance with the provisions specified in Chapter-4 of these Regulations:

Provided further that contribution to reserve for Unforeseen Exigency and Development fund to be allowed by the Commission after prudence analysis of the proposal subject to the provisions of these regulation:

Provided also that the components of the Aggregate Revenue Requirement corresponding to the transmission lines owned by West Bengal State Electricity Transmission Company Limited (WBSETCL) and conveying electricity to other States, being recovered through transmission charges under General Network Access in accordance with the Regulations and Orders of the Central Electricity Regulatory Commission, shall not be recovered from the Annual Transmission Charges determined under these Regulations

Provided also that prior period income/expenses shall be allowed by the Commission at the time of truing up based on audited accounts, on a case to case basis, if the income/expenses in that prior period have been allowed on actual basis, subject to prudence check:

Provided also that all penalties and compensation payable by the Licensee to any party for failure to meet any Standards of Performance or for damages, as a consequence of the orders of the Commission shall not be allowed to be recovered through the Aggregate Revenue Requirement whereby the details of penalties and compensation paid or payable, if any, is required to be submitted to the Commission along with its Petition.

75 Operational Norms:

75.1 Target availability for the transmission system shall be as under:

(i) For full recovery of annual transmission charges:
   a) AC system: 98.00%;
   b) HVDC bi-pole links and HVDC back-to-back stations: 95.00%;

Provided that the normative annual transmission availability factor of the HVDC bi- pole links shall be 85% for first twelve months from the date of commercial operation.

(ii) For incentive consideration:
   a) AC system: 98.50%;
   b) HVDC bi-pole links and HVDC back-to-back stations: 97.50%;

Provided that recovery of annual transmission charges below the level of target availability shall be on pro rata basis. At zero availability, no transmission charges shall be payable:

Provided further that the actual availability shall be calculated in accordance with the procedure provided in Schedule - 7 to these Regulations and shall be certified by the SLDC as per the format specified in Appendix I of the Schedule – 7 of these Regulations.

Provided also that no Incentive shall be payable for availability beyond 99.75%:

Provided also that for AC and HVDC system, actual outage hours shall be considered for computation of availability upto two tripping per year. After two tripping in a year, for every tripping, an additional 12 hours of outage shall be considered in addition to the actual outage hours:

Provided also that in case of outage of a transmission element affecting evacuation of power from a generating station, outage hour shall be multiplied by a factor of 2.

76 Determination of Transmission Charges

76.1 Annual Transmission charges for use of the Transmission system of the Transmission Licensee shall be determined by the Commission in such a way that the aggregate revenue requirement of the Transmission Licensee for the financial year as approved by the

Commission is recovered.

76.2 The aggregate of the yearly Aggregate Revenue Requirement for all Transmission Licensees shall form the **“Total Transmission System Cost" (TTSC)** of the Intra-State transmission system, to be recovered from the Transmission System Users (TSUs) for the respective year of the Control Period, in accordance with the following Formula:

$$TTSC_{(t)} = \sum_{i=1}^{n} ARRi$$

Where,

TTSC(t)	=	Pooled Total Transmission System Cost of year (t) of the Control Period;
N	=	Number of Transmission Licensee(s);
ARRi	=	Yearly revenue requirement approved by the Commission for ith Transmission Licensee for the yearly period (t) of the Control Period:

Provided that in case of transmission system projects undertaken in accordance with the Guidelines for competitive bidding for transmission under Section 63 of the Act, the Aggregate Revenue Requirement as per the annual Transmission Service Charges (TSC) quoted by such projects, shall be considered, for aggregation under the TTSC.

76.3 The Commission shall approve yearly **‘Base Transmission Capacity Rights’** for the Intra-State Transmission System (InSTS) based on the maximum drawal and average peak drawal of the Transmission System Users as projected for each year (t) of the control period, representing the 'Capacity Utilization’ of Intra-State transmission system, in accordance with the following formulae:

Base Transmission Capacity Rights (Base TCR) for the yearly period (t) $= \sum_{u=1}^{n}([0.5\ xDp(t) + 0.5\ x\ Da(t)])$

Where,

Dp(t)	= maximum drawal from InSTS in a time block during the year (t) of Control Period for each Transmission System User (u);
Da(t)	= Average of (maximum drawal from InSTS in a day) during the year (t) of Control Period for each Transmission System User

(u):

Provided that for long-term Open Access Users other than distribution licensees, the Allotted Capacity approved in terms of the Open Access Regulations shall be considered.

Provided further that the maximum drawal, average of peak drawal or the Allotted capacity, as the case may be, to be considered for determination of the yearly Base Transmission Capacity Rights shall be computed at the beginning of the Control Period based on the past trend and on the basis of demand projections made by various TSUs connected to the Intra-State transmission system as part of their MYT Petitions for the Control Period.

76.4 **Base Transmission Tariff** for each Year shall be determined as ratio of approved 'TTSC' for intra-State transmission system and approved 'Base Transmission Capacity Rights' and shall be denominated in terms of "Rs./kW/month" (for long-term/medium-term usage) or in terms of "Rs./kWh" (for short-term bilateral open access transactions usage, short-term collective transactions over Power Exchange and for Renewable Energy transactions) in accordance with the following formula:

a)	Base Transmission tariff for long-term / medium term (in Rs/MW/month)	= TTSC(t) / Base TCR(t)
b)	Base Transmission tariff for short-term	= TTSC(t) / $\sum_{i=1}^{n} Energy\ Transmitted\ by\ T(i)$

Where,

TTSC(t) = Pooled cost for InSTS for yearly period (t) of the Control Period;

Base TCR(t) = Base Transmission Capacity Rights for the yearly period (t);

N = Total number of Transmission Licensee(s) in that particular year of Control Period;

T(i) = i^{th} Transmission Licensee:

Provided that the energy units transmitted by the Transmission Licensees shall be based on the energy input requirement of the Distribution Licensees at Generation-InSTS interface point and InSTS – ISTS interface points, as projected by each Distribution Licensee as part of its MYT Petition for the Control Period and as approved by the Commission:

Provided further that any revisions in Base Transmission Capacity Rights and Base Transmission Tariff as determined in Regulations 76.3 and 76.4 due to the variation in the actual and approved CPD and NCPD shall be made at the end of the Control Period for the subsequent years:

Provided also that in case new Transmission Licensees are added to the intra-State transmission network during the Control Period, then the TTSC, Base Transmission Capacity Rights and Base Transmission Tariff as referred under Regulations 76.2, 76.3 and 76.4 shall be re-determined for each remaining Year of the Control Period.

77 Sharing of TTSC by long-term Transmission System Users

77.1 The long-term Transmission system users shall share the TTSC of the intra-state transmission system in proportion of the Base Transmission Capacity Right of each Transmission System User (TSU) to the pooled Base Transmission Capacity Right of the entire intra-state transmission system on monthly basis as per the formula below:

$$MTC(u) = LTTR(b) \times \text{Base } TCR_{(u)} / \text{Base } TCR(t)$$

Where,

MTC(u) = Monthly Transmission Charge for transmission system user (u);

LTTR(b) = Base Long-Term Transmission Tariff as per regulation 76.4(a) of these regulations;

Base TCR(u) = Base Transmission Capacity Right for user (u) determined as per regulation 76.3 of these regulations;

Base TCR(t) = Base Transmission Capacity Right for the year (t) of entire InSTS, determined as per regulation 76.3

77.2 Short-term Transmission Charge and Transmission Deviation Charge payable by a Transmission System User for drawal above its Base Transmission Capacity Right and Allocated Capacity respectively in the following manner:

(a) The Long-Term TSU with Recorded Demand (RD) in any 15-minute time block up to Base TCR shall not be subjected to payment of Short-Term Transmission Charges;

(b) Long-Term TSU with Recorded Demand in any 15-minute time block greater than Base TCR but lower than Contracted Capacity shall make payment of Short-Term Transmission Charges (STTC) for the recorded demand in excess of Base TCR;

(c) Long-Term TSU with Recorded Demand in any 15-minute time block lower than Base TCR and greater than Contracted Capacity shall not be subjected to payment of Short-Term Transmission Charges;

(d) Long-Term TSU with Recorded Demand in any 15-minute time block greater than Contracted Capacity, where Contracted Capacity is greater than Base TCR, shall make payment of Short-Term Transmission Charges for the Recorded Demand in excess of Base TCR and shall also make payment of Transmission Deviation Charge (TDC) at 25% of the Long-term transmission charge for Recorded Demand in excess of Contracted Capacity;

(e) Long-Term TSU with Recorded Demand in any 15-minute time block greater than Base TCR, where Contracted Capacity is less than Base TCR, shall make payment of Short-Term Transmission Charges for the Recorded Demand in excess of Base TCR and shall also make payment of Transmission Deviation Charge (TDC) at 25% of the Long-term transmission charge for Recorded Demand in excess of Base TCR:

Provided that the calculation of the Short-Term Transmission Charges and Transmission Deviation Charge shall be based on the 15-minute time block basis or as amended time to time:

Provided further that the applicability and calculation of the Short-Term Transmission Charges and Transmission Deviation Charge shall be as shown in the Table below:

Sr. No.	**Scenario**	**Applicable Charges**	**Calculations of charges on 15-minute time block basis**
a.	RD < Base TCR < CC	Only Monthly Transmission Charges (MTC)	STTC will not apply as RD is within Base TCR. TSU pays Transmission charges upto Base TCR.
b.	Base TCR < RD < CC	STTC in accordance clause (b) of this Regulation	STTC = (RD – Base TCR) in kW x S.T. Rate (INR/kWh)
c.	CC < RD < Base TCR	Only MTC	STTC will not apply as RD is within Base TCR. TSU pays Transmission charges upto Base TCR.

d.	Base TCR < CC < RD	STTC in accordance with clause (b) of this Regulations. TDC equal to 25% of the $LTTR_{(b)}$ for the use of InSTS in excess of its CC in accordance with clause (d) of this Regulation.	STTC = (RD – Base TCR) in kW x S.T. Rate (INR/kWh) TDC = (RD – CC) in kW x 0.25 x $LTTR_{(b)}$ (INR/kW/month)
e.	CC< Base TCR < RD	STTC in accordance with clause (b) of this Regulations. TDC equal to 25% of the $LTTR_{(b)}$ for the use of an InSTS in excess of its Base TCR in according with clause (e) of this Regulation.	STTC = (RD – Base TCR) in kW x S.T. Rate (INR/kWh) TDC = (RD – Base TCR) in kW x 0.25 x LTTC (INR/kW/month)

77.3 Revenue from short-term open access charges for each yearly period (t) of Control Period shall be taken to be same as that prevalent during the yearly period one year before the commencement of the Control Period. However, the adjustments due to variation in actual revenue from short-term open access charges and revenue from transmission deviation charges shall be undertaken during annual truing up.

78 Billing and Payment of Charges

78.1 The STU shall raise monthly bill for Intra-State Transmission Charges on every Transmission System User (TSU) on the first working day of the month for the Transmission Charges of preceding month.

78.2 All TSUs shall ensure timely payment of Transmission Tariff to STU so as to enable STU to make timely settlement of claims raised by Transmission Licensees.

79 Transmission losses

79.1 The Commission shall examine the filing made by the Transmission Licensee in respect of transmission loss and shall approve a transmission loss trajectory for each year of the Control Period based on the opening loss levels, licensee's filings/submissions, past trends, and any other factor considered relevant by the Commission. This approved loss target will be used for computing estimated energy for transmission in licensee's system for that year.

79.2 Energy losses in the transmission system of the Transmission Licensee, as determined by the SLDC, shall be borne by the

Transmission System Users in proportion to their usage of the Intra-State Transmission System. SLDC shall compute the transmission loss on weekly basis along with the Deviation Settlement Account and uploaded the same in its website. The actual transmission loss of week (n) shall be used by SLDC while preparing the Schedules of Transmission System Users for the $(n+3)^{rd}$ week:

Provided that the quantum of energy consumed by the auxiliary equipment of a transmission substation and the station transformer losses within the sub-station shall not be accounted for under the Transmission Losses:

Provided further that the energy consumed for supply of power by the transmission sub-station to the associated offices of the Licensee, its housing colony and other facilities, and for construction works at the sub-station, shall not be considered as energy consumed by the auxiliary equipment of a transmission sub-station:

80 Incentive / Disincentive:

80.1 An additional rate of Return on Equity of 0.05% shall be allowed on Transmission Availability for every 0.25% over-achievement from the target Availability for incentive specified in clause (ii) of regulation 75.1 of these regulations, subject to ceiling of additional rate of Return on Equity of 0.25%.

80.2 Similarly, the Transmission Licensee shall be liable for a dis-incentive in terms of reduction of rate of Return on Equity of 0.05% for every 0.25% under-achievement from the minimum requirement of 98.00%, subject to a ceiling of additional rate of return of 0.25%.

80.3 Transmission availability shall be certified by SLDC as per Schedule-7 of these Regulations.

81 Reactive Energy Charge:

81.1 A Generating Station shall inject/absorb the reactive energy into the grid on the basis of machine capability as per the provisions of State Grid Code and directions of SLDC.

81.2 Reactive energy exchange, only if made as per the directions of SLDC, for the applicable duration (injection or absorption) shall be compensated/levied by the SLDC to the Generating Station, at a rate to be specified by the Commission through separate order or regulations.

81.3 The Transmission System Users shall be subjected to Incentive/Disincentive to be compensated/levied by the SLDC for maintaining the reactive energy balance in the transmission system, as specified in the State Grid Code and amendments thereof. The rate of incentive / disincentive shall be same as that specified by the CERC from time to time.

CHAPTER 7

DISTRIBUTION

82 Applicability

82.1 The Regulations contained in this Chapter shall apply for determination of wheeling charges and retail supply tariff of a distribution licensee along with the terms and conditions of the tariff.

82.2 Retail supply tariff is payable by the consumer of Distribution Licensee for the part of energy drawn by the consumer not as open access consumer who has got open access under section 42 of the Act.

82.3 Wheeling charge are payable for usage of distribution wires of a Distribution Licensee by a Distribution System User who has been allowed open access to the distribution system under section 42 of the Act following the procedure laid down in the Open Access Regulations.

82.4 In case of distribution of electricity in the same area by two or more distribution licensees, the Commission may fix the maximum ceiling of tariff for retail sale of electricity and may be guided by principles contained in these regulations in fixing such tariff.

83 Petition for determination of Tariff

83.1 A Distribution Licensee shall file a combined petition for determination of Tariff for retail supply of electricity and wheeling charges in accordance with the provisions of Chapter-3 of these Regulations.

83.2 Distribution licensee in its petition shall separately submit the computation for wheeling charges and retail tariff based on the allocation matrix specified in regulation 83 of these regulations.

83.3 The Distribution Licensee along with its Tariff petition shall submit the followings:

(i) Capital Investment Plan for each year of the Control Period prepared as per the Guideline of Capital Expenditure Framework specified in Schedule – 3 of these regulations;

(j) Demand and Sales Forecast and Power Purchase Plan for each year of the Control Period prepared as per the Framework for Resource Adequacy specified in Schedule-2 of these Regulations. The power purchase plan shall mention the source, nature, tenure of supply and expected tariff. Distribution Licensee shall submit copies of approved PPAs;

(k) Long-term Distribution Resource Adequacy Plan (LT-DRP) vetted by the Central Electricity Authority and the MT-DRP and ST-DRP prepared as per the Schedule -2 of these Regulations.

84 Components of Tariff

84.1 The Wheeling charge payable by distribution system users comprises of distribution network costs and the retail supply tariff payable by consumers of the distribution licensee comprises of both distribution network cost and power supply cost.

84.2 The wheeling charge and retail supply tariff shall provide for recovery of the total Aggregate Revenue Requirement of the Distribution licensee for the respective year of the Control Period, as approved by the Commission and comprises of the following components:

(a) Cost of own power generation /power purchase expenses;

(b) Inter-State Transmission Charge;

(c) Intra-State Transmission Charge;

(d) RLDC/ SLDC Fees & Charges

(e) Operation and maintenance expenses;

(f) Depreciation;

(g) Interest on Loan Capital;

(h) Interest on working capital;

(i) Return on Equity;

(j) Interest on consumer security deposits;

(k) Statutory fees, if any;

(l) Contribution to reserve for Unforeseen Exigency, if any;

(m) Contribution to Development Fund, if any;

minus:

(n) Non-Tariff income;

(o) Income from sale of surplus power;

(p) Income from Other Business, to the extent specified in these Regulations:

Provided that Operation & Maintenance expenses, Depreciation, Interest on Loan Capital, Interest on working capital, Interest on deposits from Distribution System Users, Return on Equity and contribution to development fund and reserve for Unforeseen Exigency, Non-tariff income and sharable income from other business shall be allowed in accordance with the provisions specified in Chapter-4 of these Regulations:

Provided further that cost for own generation shall be determined in accordance with the provisions specified in Chapter-5 of these Regulations. Distribution licensee shall submit the petition for determination of tariff from own generation along with its petition for distribution tariff:

Provided also that prior period income/expenses shall be allowed by the Commission at the time of truing up based on audited accounts, on a case to case basis, if the income/expenses in that prior period have been allowed on actual basis, subject to prudence check:

Provided also that all penalties and compensation payable by the Licensee to any party for failure to meet any Standards of Performance or for damages, as a consequence of the orders of the Commission, Courts, Consumer Grievance Redressal Forum, and Ombudsman, etc., shall not be allowed to be recovered through the Aggregate Revenue Requirement:

Provided also that the Distribution Licensee shall maintain separate details of such penalties and compensation paid or payable by the Licensee, if any, and shall submit them to the Commission along with its Petition.

85 Power Purchase Cost:

85.1 Power Purchase Cost shall be projected in commensurate with the power purchase plan for each year of the distribution licensee ensuring the requirement of merit order despatch. Any power purchase shall come into effect only after approval of the Power Purchase Agreement approved by the Commission in terms of the provisions of Chapter-8 of these Regulations.

85.2 The power purchase rate for all long-term / medium-term purchase shall be considered as per rate approved in the power purchase agreement by the Commission:

Provided that where tariff is agreed to be determined under section 62 of the Act, the latest approved tariff by the appropriate Commission shall be considered for fixed charge and average energy charge of previous 12 months shall be considered:

Provided further that where tariff is discovered under section 63 of the Act and the Commission has adopted such tariff, the same shall be considered:

Provided also that for the proposed long-term / medium-term purchase, where PPA has not been approved by the Commission, the distribution licensee shall project the tariff based on the existing tariff of the power source or tariff of similar power plant, with justification:

Provided also that for any proposed short-term power purchase, Distribution Licensee shall consider the average cost of power in the power exchanges:

85.3 The cost of Banking / swapping of power, if any, shall be adjusted with the power purchase cost as per the provisions of Chapter -8 of these Regulations.

85.4 Any rebate on power purchase or any prior period arrear shall not be considered during the tariff, unless specifically directed by the Commission:

Provided further that any variation in the power purchase cost after issuance of the Tariff order shall be recovered through monthly FPPSA formula specified in Schedule-4 of these Regulations.

86 Transmission charges:

86.1 Distribution Licensee shall be allowed to recover transmission charges payable for access to and use of the Inter-state and Intra-State Transmission System. The transmission charge shall be based on the charges determined by the appropriate Commission. During trueing up the actual audited figure shall be considered:

Provided also that any rebate on transmission charge or any prior period arrear shall not be considered during the tariff, unless specifically directed by the Commission.

87 SLDC/ RLDC Fees and Charges

87.1 RLDC/ SLDC fees and charges and any other statutory fees shall also be payable and to be projected based on the figures of base year. During trueing up the actual audited figure shall be considered.

88 Income from sale of incidental surplus

88.1 Cost of incidental sur-plus power, if any, based on the load-generation balance analysis, shall be considered at average energy charge rate of all long-term and medium-term power purchase including cost of own generation in a reverse merit order, i.e the costliest power to be considered first.

88.2 During tariff determination, the cost of incidental surplus shall be deducted from the proposed power purchase cost to arrive at the cost of power purchase for supply to consumers.

88.3 During truing-up the income from sale of surplus power shall be computed after reducing the cost of incidental surplus power derived as per regulation 88.1 of these regulations and cost associated with sale of surplus power from the revenue earned from sale of surplus power.

88.4 The income from sale of surplus power shall be shared equally between the consumer and the distribution licensee during truing-up. However, if any loss arises out from such activity, such loss shall not be allowed to be adjusted against Aggregate Revenue requirement.

89 Allocation of ARR between Network function and Supply function

89.1 The Aggregate Revenue Requirement of the Distribution Licensee shall be apportioned between the Distribution network function and Supply function in accordance with the following Allocation Matrix**:**

Particulars	**Distribution Network function (%)**	**Distribution Supply function (%)**
Cost of Own Power Generation	0%	100%
Power Purchase Expenses	0%	100%
Inter-State Transmission Charges	0%	100%
Intra-State Transmission Charges	0%	100%
RLDC, SLDC fees & Charges	50%	50%
Statutory Charges	50%	50%
Operation & Maintenance Expenses	65%	35%
Depreciation	90%	10%
Interest on Long-term Loan Capital	90%	10%

Return on Equity	90%	10%
Interest on Working Capital	10%	90%
Interest on Consumer Security Deposits	0%	100%
Provision for Bad & Doubtful Debts	0%	100%
Contribution to Contingency Reserves	90%	10%
Non-Tariff Income	10%	90%

Provided that where Distribution Licensee has maintained separate accounting for segregation of its assets between the network function and wire function, the same shall be considered.

90 Determination of Wheeling Charges:

90.1 The components of Aggregate Revenue requirement of the Distribution Business, specified in regulation 84 of these Regulations and approved by the by Commission shall be shared among the wire

90.2 The ARR related to the distribution network function shall be derived by applying the allocation matrix specified in regulation 84 of these Regulations on the components of total ARR of the Distribution Business.

90.3 The Commission may determine wheeling charge for different voltage level or composite wheeling charge for the distribution licensee area.

90.4 Distribution Wheeling Charge for each year of the control period shall be derived by the following formulae:

$$Wheeling\ Charge \quad = \frac{ARRw}{Ew\ x\ 10} \quad \text{in paisa/kWh}$$

Where,

ARRw =ARR of Distribution network function in INR Lakh;

Ew = Projected energy to be wheeled through the distribution network = wheeling of energy of distribution system users under open access + sale to own consumers of distribution licensee, in MU;

Provided that where distribution licensee has completed voltage wise asset segregation, the Commission shall determine the voltage wise wheeling charge, considering the voltage level wise ARR and energy wheeled.

Provided further that the consumers of distribution licensee are not liable to pay wheeling charge for the energy it is getting supply from the Distribution Licensee. The distribution network usage charge is inbuild in their retail tariff:

Provided also that the revenue from Wheeling Charges paid by the Distribution System Users under the above proviso shall be used to reduce the Aggregate Revenue Requirement to be recovered from the retail consumers of the concerned Distribution Licensee.

90.5 The Distribution Licensee shall be allowed to recover the approved level of wheeling loss as specified in the open access Regulations, Wheeling loss arising, in kind, from the distribution system users.

91 Aggregate Revenue Requirement for Retail Supply

91.1 The Aggregate Revenue Requirement of the Distribution licensee adjusted with the revenue recoverable through wheeling charges shall be considered for ARR for retail supply to be recovered through retail supply tariff:

Provided also that the receipt of revenue on account of cross-subsidy surcharge and additional surcharge shall be considered only at the time of truing up exercise, based on actual receipts as per Audited Accounts.

92 Receipts on account of cross-subsidy surcharge:

92.1 Cross-subsidy surcharge received by the Distribution Licensee in accordance with the West Bengal Electricity Regulatory Commission (Open Access) Regulations, 2022, as amended from time to time, at the rate approved by the Commission shall be deducted from the Aggregate Revenue Requirement for retail supply in calculating the tariff for retail supply of electricity by such Distribution Licensee, at the time of truing up.

93 Receipts on account of Additional Surcharge:

93.1 Additional surcharge received by the Distribution Licensee in accordance with the West Bengal Electricity Regulatory Commission (Open Access) Regulations, 2022, as amended from time to time, at the rate approved by the Commission shall be deducted from the Aggregate Revenue Requirement for retail supply in calculating the tariff for retail supply of electricity by such Distribution Licensee, at the time of truing up.

94 Deviation Settlement Charges

94.1 For a distribution licensee net receivable Deviation Settlement Charge charges on actual basis for any previous year or base year or ensuing year shall be considered as income for the period of the previous year or the base year or the ensuing year concerned when Deviation Settlement Charge receivable in a year is greater than Deviation Settlement Charge payable during that year. If the Deviation Settlement Charge payable is higher than the Deviation Settlement Charge receivable during a year, then the net Deviation Settlement Charge will be considered as expenditure but that shall be limited to 5% of the total power purchase cost for that ensuing year.

94.2 The net Deviation Settlement Charge admissible in terms of regulation 94.1 of these regulations shall be adjusted with the power purchase cost during truing up.

95 Distribution Loss

95.1 The power purchase requirement of the Distribution Licensee at the Transmission-Distribution interface point, shall be computed by grossing up the sales with the distribution losses approved by the Commission.

Provided that the Commission may stipulate the target distribution losses for each year of the control period, in accordance with Regulation 6 as part of the Order on the Multi-Year Tariff Petition:

Provided further that while stipulating a trajectory for distribution losses as above, the Commission may take into consideration various factors including past trend, demand growth, proposed measures for reducing loss under taken by the licensee, loss reduction trajectory, if any, approved by Government of India or State Government under any Scheme and the best practices of similarly situated licensees in the country.

95.2 The Distribution Licensee as a part of its MYT Petition shall also submit the AT&C Loss trajectory duly considering any trajectory agreed / approved under State Government or Central Government Schemes:

Provided that the Commission may stipulate trajectory for AT&C losses in its Order on the MYT Petition filed by Distribution Licensee.

95.3 Variation between the actual level of distribution and AT&C losses and the approved level shall be dealt with, as part of the Truing up exercise.

95.4 For the purpose of these regulations AT&C losses shall be computed as per Schedule-8 of these Regulations.

96 Reliability Indices:

96.1 Distribution licensee has to compute the System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Momentary Average Interruption Frequency Index (MAIFI) on monthly basis, as well as rural and urban area separately, as per the formula specified in Schedule-8 of these regulations. Distribution licensee shall update the report with computation details in its website and submit the same to the Commission. An annual statement comprising of monthly data shall be submitted along with the true-up petition.

96.2 The distribution network availability shall be computed as

Network availability = {1- (SAIDI/8760)} x 100

96.3 Distribution licensee shall endeavor to maintain network availability within 98.00% on annual basis. If any distribution licensee achieves availability more than 98.50%, an incentive in terms of additional return on equity as per Regulation 96.4 of these regulations shall be applicable. Similarly, in case distribution licensee fails to maintain network availability upto 98.00%, it shall be liable for disincentive in terms of Regulation 96.5 of these regulations:

The Commission shall notify the date from which these incentives / disincentives are applicable, subject to the readiness of the licensee, based on the plan submitted by the licensee as specified in regulation 96.6 of these regulations.

96.4 Distribution Licensee shall be liable of additional rate of return on equity of 0.05% for every 0.25% over-achievement from the target availability of 98.50%, subject to a ceiling of additional rate of return of 0.25%.

96.5 Similarly, the Distribution Licensee shall be liable for a dis-incentive in terms of reduction of rate of Return on Equity of 0.05% for every 0.25% under-achievement from the minimum requirement of 98.00%, subject to a ceiling of additional rate of return of 0.25%.

96.6 The data for computation of SAIFI, SAIDI and MAIFI shall be captured directly from the feeder monitoring system through smart meters. All computations should be done automated measurement records and without manual intervention. Distribution licensee in its MYT petition shall submit the detailed plan for installation of meters in each DT including provisions of AMR of all DT meters and consumer meters along with the mechanism for computations and monitoring of the reliability indices, following the guidelines issued by the Central or State Government or specified by the Commission from time to time.

97 Determination of Retail Supply tariff

97.1 The Commission may categorize consumers on the basis of their load factor, power factor, voltage, total consumption of electricity during any specified period or the time at which the supply is required or the geographical position of any area, the nature of supply and the purpose for which the supply is required.

97.2 The retail supply tariff for different consumer categories shall be determined on the basis of the Average Cost of Supply, computed as the ratio of the Aggregate Revenue Requirement for retail supply of the Distribution Licensee for the financial year calculated in accordance with Regulation 91 of these Regulations, and including unrecovered revenue gaps of previous years to the extent proposed to be recovered to the total sales to consumers of the Distribution Licensee for the respective year.

97.3 The Commission shall endeavor to reduce gradually the cross-subsidy between consumer categories with respect to the average cost of supply in accordance with the provisions of the Act. The tariff for any consumer category shall remain within +/- 20% of the Average Cost of Supply, except for the cases of consumers below poverty line and agriculture consumers.

97.4 While determining the tariff the Commission may also keep in view the cost of supply at different voltage levels and the need to minimize tariff shock to any category of consumers.

97.5 The Tariff for retail supply may comprise any combination of fixed/demand charges, energy charges, minimum charge and any other charges/incentives, for the purpose of recovery from the consumers, as may be stipulated by the Commission

97.6 Rent for meter or any other equipment(s) provided by the licensee at the premises of a consumer and other charges are non-tariff charges that shall be determined by the Commission:

Provided that no meter rent shall be applicable if the cost of the meter is given by the consumer.

97.7 While submitting the MYT tariff petition the Distribution Licensee shall submit the its proposal for fixed/ demand charge, energy charge, and all other charges / incentive for all category of consumers specified in Annexure C1, as applicable, in such form and manner as specified in these Regulations.

98 Determination and computation Demand/ Fixed Charge:

98.1 The recoverable fixed charge from consumer through tariff shall be determined by the Commission through tariff order from time to time and it may be part or full value of the applicable fixed charge in terms of the ceiling of the fixed charge as detailed below. The ceiling of the fixed charge against each KVA of contract demand of a consumer of a licensee for a month shall be FC_UL where

$$FC\_UL = \frac{\text{Annual Fixed Cost in rupees for the licensee for the ensuing year}}{\text{(Projected peak demand of the licensee in KVA for the ensuing year based on projected sale of its electricity to its consumers in that year)} \times 12}$$

Where projected peak demand of the licensee in KVA based on sale of electricity to the consumer in the ensuing year as mentioned in denominator is computed by reducing the projected maximum system peak demand, projected on the basis of past trend, by the amount proportionate to normative average distribution loss of that ensuing year.

98.2 The recoverable demand charge from consumer through tariff shall be determined by the Commission through tariff order time to time and it may be part or full value of the applicable demand charge in terms of the ceiling of the demand charge as detailed below. The ceiling of monthly Demand charge against each KVA of contract demand of a consumer of a licensee for a month will be DC_UL where

$$DC\_UL = \frac{\text{Demand /Capacity Charges in rupees to be paid annually as per agreement by licensee with other licensee or generating company irrespective of power drawn or not}}{\text{(Projected peak demand of the licensee in KVA for the ensuing year based on projected sale of its electricity to its consumers in that year)} \times 12} + FC\_UL$$

and FC_UL is as defined in regulation 98.1. The denominator of the first term in the above formula is computed in the same method as specified in the regulation 98.1.

98.3 The Demand/Fixed Charges shall be gradually increased year-on-year basis upto the ceiling specified in regulation 98.1 and 98.2 above to recover annual Fixed Cost and capacity charge payable by the Distribution Licensee from such Demand/Fixed Charges:

Provided further that the basis for the determination of consumer category wise Demand/Fixed Charges for the respective years of the Control Period, shall be in terms of their actual Billing Demand at HT and LT Level, change in Load Factor, change in number of connections in case of LT level, etc.

Provided further that the Distribution Licensee shall submit the details of the actual Billing Demand, Contracted Capacity, Load Factor and Connected number of Consumers for the respective Consumer categories as part of the MYT Tariff Petition.

98.4 Fixed charges shall be applicable for LV and MV consumers having contract load below 50 KVA and quantified in terms of per KVA/month, based on their contract demand. For fixed charge computation of any consumer, contract demand below 1 KVA shall be treated as 1 KVA.

98.5 Demand charge will be applicable to all HV and EHV consumers and also to those LV and MV consumers who have contract load of 50 KVA or above and at a rate as stipulated in the respective tariff order. Demand Charge shall be levied on the basis of maximum demand, recorded during the month or 85% of the contract demand whichever is higher.

Provided that no demand charge shall be payable by any consumer for that period when load of the consumer is interrupted/ totally shed/ partially restricted because of any fault of the licensee or its system or for non-availability of power with the licensee due to lower availability of power from its own generating station and / or its other suppliers of power or imposition of any restriction by the licensee on drawal of power by consumer. However, such exemption from demand charge shall not be available if the interruption is caused by grid failure or automatic under-frequency relay tripping or any force majeure event not related to licensee or due to disconnection of supply for any fault on the part of the consumer.

98.6 The demand charge payable in a billing period for a consumer shall be determined in accordance with the following formula:

$$DC = DC_A \times (H - \Sigma H_i) \times MD + \Sigma(H_i \times RD_i)H$$

Where,

DC = Computed Demand Charge applicable to a consumer for billing period;

DC_A = Applicable rate of demand charge for a consumer;

H = Total hours in the billing period;

Hi = The duration involved for i_{th} incidence of interruption / total shed/partial restriction in supplying power to the consumer;

MD = Maximum Demand considered for levying demand charge as per regulation 96.4 of these regulations;

RDi = Restricted load imposed on the consumer corresponding to ith incidence or actual drawal during the period of such restriction whichever is higher.

98.7 The demand charge shall be based on the data available from the recording in consumer's meter of average supply in terms of demand for every 15 minutes time block as is applicable under ABT mechanism.

98.8 In case of non-availability of demand in KVA the said demand shall be converted from KW by considering average power factor of the concerned period or a power factor of 0.85 if the average power factor cannot be calculated because of non- availability of data.

98.9 No consumer shall be made to pay both demand charge and fixed charge simultaneously.

98.10 Notwithstanding anything to the contrary contained anywhere in these regulations, in cases where no consumption of energy has taken place for any reasons whatsoever including disconnection of supply due to fault on the part of the consumer but excluding instances of interruption in supply due to failure on the part of the licensee, the fixed charge or demand charge of a consumer, as the case may be, shall be calculated on the basis of the contract demand

98.11 When a licensee bills a consumer for consumption of electricity covering only a part of month caused by discontinuance of consumership before the expiry of a full month, the computation of fixed charge or demand charge shall be made for the entire month excepting for such consumers under the short-term supply for whom such billing shall be pro-rata for the number of days for such supply in that particular month.

98.12 For the purpose of these regulations, the contract demand shall mean the electrical load in Kilo Watt (KW) or in Kilo Volt Ampere (KVA) which, in accordance with the signed contract or agreement between the licensee and the consumer, the licensee has committed to deliver and the consumer has right to draw at the delivery point of the consumer at any or all time during the currency of the contract or agreement, except under specific grid/ network conditions specified in regulation 103.4 of these Regulations.

99 Determination and Computation of Energy Charge

99.1 The Commission shall determine the consumer category wise Energy Charges for the respective Distribution Retail Supply Licensee taking into consideration consumer's load factor, power factor, voltage, total consumption of electricity during any specified period or time at which the supply is required or the geographical position of any are, the nature of supply and the purpose for which the supply is required, prevalent cross-subsidy, adherence to tariff policy provisions etc., for the respective financial year of the Control Period:

Provided that such Energy Charges shall be gradually revised year-on-year basis to reduce the level of cross-subsidy as permissible as per provisions of Tariff Policy and also encourage efficient use of energy by various consumer categories:

Provided further that the basis for the determination of consumer category wise Energy Charges for the respective years of the Control Period, shall be in terms of their actual consumption at HT and LT Level, change in Load Factor, incremental consumption rebate, if any, time of use charge implications, etc.

Provided further that the Distribution Licensee shall submit the required details of the consumption of various consumer categories and slab-wise consumption details for the respective Consumer categories as part of the MYT Tariff Petition.

99.2 Energy charge shall be recovered by the Distribution company for the billing cycle as specified in the regulation notified under section 50 of the Act and based on the consumption of electricity recorded in the electric meter.

99.3 The Commission may make TOD or pre-paid metering mandatory within certain time frame for any class of consumers as may be specified by the Commission in due course besides those specified in regulation 102.2 of these regulations.

99.4 The consumer opting for pre-paid meter shall not be required to furnish any security deposit for the energy charge.

99.5 The Commission may differentiate tariff or rebate or discount or surcharge or penalty for use of TOD and / or pre-paid meter to provide incentive for efficient use of electricity, ensuring better demand side management and for increased operational efficiency of licensee.

100 Treatment of Power factor

100.1 The Commission may direct certain class of consumers to maintain power factor at a stipulated level, as may be decided by the Commission, and allow incentive or impose penalty through rebate or surcharge for maintaining power factor above or below the stipulated level, as the case may be.

100.2 The power factor rebate or surcharge shall be on energy charge only.

100.3 In addition to existing rebate / surcharge on power factor applicable on the certain classes of consumers, the rebate and surcharge on power factor shall also become applicable for all HT / EHT consumers and the following LT consumers at a rate as will be stipulated in the tariff order:

(i) LT Industrial;
(j) LT Public Water Works; and
(k) LT Commercial having Contract Demand 10 kVA and above.

100.4 All distribution licensees shall install power factor controllers for all LT consumers with contract demand of 10 KVA and above, except the LT consumers eligible for rebate / surcharge on power factor as mentioned in regulation 100.3 above. Consumers eligible for power factor rebate / surcharge have to install power factor controller / capacitor bank at their own cost.

101 Treatment of Load factor

101.1 The Commission may direct certain class of consumers to maintain load factor at a stipulated level, as may be decided by the Commission, and allow incentive or impose penalty through rebate or surcharge for maintaining load factor above or below the stipulated level, as the case may be.

101.2 For the purpose of billing, the load factor of a consumer for a billing month shall be determined in accordance with the following formula:

$$Load\ factor\ (\%) = \frac{Energy\ Consumed\ in\ kWh\ for\ the\ billing\ period\ x\ 100}{(H - \Sigma H_i)\ x\ (MD) +\ \Sigma(H_i\ x\ RD_i)}$$

Where,

H = Total Hours in the billing period;

MD = Maximum Demand for Load Factor Calculation
= Recorded maximum demand in the billing period or 85% of the contract demand whichever is higher;

Hi = The duration involved for i^{th} incidence of interruption / total shed/ partial restriction on load in supplying power to the consumer by the licensee.

RDi = Restricted load imposed on the consumer corresponding to i^{th} incidence or actual drawal during the period of such restriction whichever is higher

101.3 For the purpose of load factor calculation as provided in regulation 101.2 of these regulations, the following principles shall be followed:

i) If Maximum Demand (MD) is in KVA, it shall be converted into KW by using the formula: KW = KVA X PF, where PF is the power factor.

ii) If RDi is in KVA, it shall be converted into KW by using the formula: KW = KVA X PF, where PF is the power factor.

iii) PF shall be considered as average power factor of the month when 85% or less of the contract demand is recorded maximum demand.

iv) When maximum demand (MD) represents actual recorded maximum demand, which is higher than 85% of contract demand, PF will be the actual average power factor of the time block corresponding to the period of recording the maximum demand.

v) For total shedding or interruption, RDi shall be considered as zero.

101.4 Notwithstanding anything contrary contained elsewhere in these Regulations, for load factor rebate calculation the maximum demand recorded below the contract demand may not be considered for the winter season if Commission decides so in the tariff order and in such case load factor rebate shall be considered on the basis of contract demand only.

102 Time of Day tariff

102.1 The Time-of-Day Tariff shall be applicable to all the Distribution Licensees operating in the State from the date of issuance of the MYT Tariff Order for the Control Period.

102.2 Distribution licensee shall propose ToD tariff for its consumers with load of 10 kW and above based on the following indicative time slots and tariff as percentage of energy charge:

(i) Peak period tariff for commercial and industrial consumers shall not be less than 1.20 times of the normal tariff and for other consumers, it shall not be less than 1.10 times of the normal tariff;

(ii) Tariff for solar hours of the day shall be at least 20 percent less than the normal tariff;

(iii) For the above purpose the duration of normal, peak, off-peak and solar hours shall be as below:

Solar Hours	Peak hours	Off-peak	Normal hrs
08:00 - 16:00	17:00 - 23:00	23:00 - 06:00	06:00 – 8:00 & 16:00 – 17:00

Provided that Distribution Licensee may propose seasonal tariff in its Tariff Petition:

Provided further that Distribution licensee can propose ToD tariff for any consumer category having contracted capacity less than 10 kW:

Provided also that the distribution licensee to propose their ToD time slots with slot-wise rebate/penalty at the time of MYT or MTR Tariff filing subjected to compliance of the applicable MoP Rules:

102.3 Provided further that the Commission at the time of MYT Order proceedings may extend the applicability of the ToD Tariff to the other consumer categories after assessing the growth in the demand.

103 Other terms and conditions of tariff

103.1 Any variation in power purchase cost or cost of own generation and transmission charge payable to the Transmission company from the amount approved in the ARR of the tariff order shall be recovered through Fuel and Power Purchase Adjustment Surcharge (FPPAS) in a manner as specified in Schedule- 4 of these Regulations. FPPAS shall be levied in addition to fixed/demand charge and energy charge specified under these Regulations.

103.2 All short-term supply or short-term irrigation supply or short-term supply for commercial plantation or construction supply or emergency supply or common services for industrial estate in LV & MV class of consumers shall be on pre-paid meter basis with activated current limiter and load limiter. In case of technical limitation of pre-paid meter to cater the demand of connected load, multiple pre-paid meters may be used wherever possible.

103.3 Rebate based on Maximum Demand recorded as per following conditions:

a) If in any month for any consumer the maximum demand recorded during peak period as defined in regulation 102.2 of these Regulations does not exceed 50% of maximum demand considered for the purpose of demand charge calculation of any month, the Commission may provide certain rebate which may vary according to the season;

b) The Commission may provide certain rebate in any month which may vary according to the season on the basis of fulfillment of the following two conditions:

(i) if in any month for any consumer the maximum demand recorded during peak period within the month is equal to or less than the maximum demand recorded during the periods other than peak period within the month; and

(ii) if in any month for any consumer the average drawal during peak period within the month is not greater than the average drawal of the month covering peak period, normal period and lean period

103.4 Load restriction / load shedding:

Distribution Licensee may impose load restriction or load shedding only during the following situations:

(iv) When directed by SLDC to maintain the overall safety of the State Grid;

(v) In case of up-stream network outages, where power supply is not possible or limited supply of power is possible due to technical considerations;

(vi) In case of breakdown / shutdown of distribution network elements supplying power to the consumer or group of consumers;

(vii) In case of sudden outage of generating station supplying power to the distribution licensee.

Provided that Distribution Licensee shall take all possible attempts to avoid load restrictions / load shedding to the extent possible. Load restriction / shedding shall be treated as the last resort and distribution licensee shall endeavor to normalize the supply as early as possible.

Provided further that load restriction shall be applicable to all HV & EHV consumers and also to those L&MV consumers having contract demand 50 KVA and above:

Provided also that for planned shutdown, distribution licensee shall intimate the consumers in advance following the procedures specified by the Commission:

Provided also that in case of sudden outage of generation source, Distribution Licensee shall arrange power from alternative sources as early as possible.

103.5 If the load restriction / load shedding has been imposed by the Distribution Licensee to any consumer, the consumer is not liable to pay any demand charge or pay demand charge upto the restricted load, as the case may be, for the duration of shedding/ restriction.

103.6 In case the consumer draws power more than the restricted drawal, if any, imposed by the Distribution Licensee, the excess energy drawal during each 15-minute time block shall be charged at a rate twice the applicable rate for that consumer during that time block.

103.7 If the supply is disconnected by the distribution licensee at the request of the consumer, the agreement of supply with the consumer shall stand terminated from the date of disconnection. This is, however, without any prejudice to any other compensation if the consumer is entitled to such compensation because of applicability of any other law for the time being in force or the Electricity Act 2003 or the Regulations made thereunder.

103.8 If a consumer, having a captive generating plant willing to synchronize its captive plant with the distribution system of a distribution licensee for enhancement of its reliability and security of operation, it shall pay a parallel operation / grid support charge at a rate to be specified by the Commission in the tariff order of the licensee.

103.9 If a consumer consumes power in excess of his contract demand, he shall be liable to pay additional charges as stipulated below.

a) If the highest demand of any non-TOD consumer recorded in a month exceeds his contract demand, he shall be liable to pay demand charge at the applicable rate for that non-TOD consumer in question. In addition, he will be also liable to pay an additional demand charge at the rate of 60% of the demand charge for the additional demand being the difference between the recorded highest demand and his contract demand. Excess energy drawal corresponding to the aforesaid excess demand shall be billed at the rate of energy charge applicable for such consumer.

b) In case the highest demand of any consumer under TOD tariff exceeds the contract demand in any month, the demand charge as mentioned in the tariff schedule of the tariff order for any year shall apply on highest demand for that month. In addition, the demand of power in excess of sanctioned contract demand in any period of time shall attract the additional demand charge for the said excess demand for such consumer, and the same shall be calculated according to the following formulae:

(i) In case the highest demand during normal period exceeds the contract demand

$$ADCED = 0.2 \text{ X } (Dact - Dcont) \times DC$$

(ii) In case the highest demand during peak period exceeds the contract demand

$$ADCED = 0.5 \text{ X } (Dact - Dcont) \times DC$$

(iii) In case the highest demand during off-peak period exceeds the contract demand

$$ADCED = 0.1 \text{ X } (Dact - Dcont) \times DC$$

(iv) In case the highest demand during solar period exceeds the contract demand

$$ADCED = 0.80 \text{ X } (Dact - Dcont) \text{ x } DC$$

Where,

ADCED = Additional Demand Charge for demand of power in excess of sanctioned contract demand during the billing period.

Dact = Actual highest demand of power in respective time period.

Dcont = Sanctioned Contract Demand of the consumer.

DC = Rate of Demand Charge as per the tariff order for the relevant category of consumer.

c) In case demand of power exceeds sanctioned contract demand in more than one time period, computation of Additional Demand Charge (ADCED) shall be done for each such time period and the highest among such computed additional demand charge for different time periods shall be chargeable.

d) Excess energy drawal corresponding to any excess demand shall be billed at the applicable energy charge for such consumer.

e) In case of application of regulation 98.6 in a month the additional demand charge computed as per clause (a) and (b) above shall further be adjusted through reducing the amount by a multiplying factor of DC/(MD × DCA) where DC, DCA and MD are specified in regulation 98.6.

103.10 When a licensee bills a consumer for consumption of electricity covering only a part of month caused by discontinuance of consumership before the expiry of a full month, the computation of fixed charge or demand charge shall be made for the entire month excepting for such consumers under the short-term supply for whom such billing shall be pro-rata for the number of days for such supply in that particular month.

103.11 All statutory levies like Electricity Duty or any other taxes, duties, cess etc. imposed by the State Govt. / Central Govt. or any other competent authority on sale of electricity shall be extra and shall not be a part of the tariff as determined under these regulations.

103.12 All billing parameters of a bill shall be construed for a billing period only, which has been specified by the Commission, irrespective of the date on which the meter reading is taken in accordance with any regulation made by the Commission.

103.13 In order to remove noise from the system the Commission may introduce rebate and/ or surcharge to any class of consumers through any formula on the basis of any form of measurement of harmonics and applicable from a date which will be stipulated in any tariff order.

103.14 Distribution licensee shall review the contract demand of the consumer annually based on the consumption of the preceding year as per the following formula:

$$[Contract\ Demand = \frac{Annual\ Consumption\ in\ Unit}{Number\ of\ days\ in\ year\ x\ 24\ x\ LF}$$

Where,
LF is the annual average load factor of same category of consumers

103.15 If the value of the calculated contract demand as per regulation 103.16 found to be higher than the contract demand as recorded with the licensee, then such contract demand will be revised prospectively. In case such calculated contract demand is not an integer, then it shall be rounded off to next integer in KW. The consumer category shall also be changed for those consumers, if required due to such revision of contract demand. Due to such change in contract demand if infrastructure to provide such supply is required to be changed for technical requirements then corresponding service connection charge for additional load enhancement is to be provided by the consumer according to SOP or any procedure framed under it as applicable. In case of change of category of consumer where technically infrastructure is to be changed consumer shall be provided with a notice for submission of application for enhancement of load as per regulations. In response within one month consumer shall either enhance the contract demand or give a declaration as per declaration format of the licensee that it shall be continued with the present contract demand subject to fulfillment of the regulation 103.18 wherever its recorded demand in a month falls under the application of the regulation 101.18.

103.16 If the maximum demand, of a consumer who has opted to abide by the regulation 103.17, recorded is found to be higher than the contract demand where such recorded maximum demand falls in the category of consumer which is determined on the basis of contract demand, then the consumer is required to pay the fixed charge or demand charge in accordance to the formula that will be provided in the tariff order.

103.17 For any class of the consumers for whom minimum charge is stipulated in the tariff order, such minimum charge shall be applicable when the sum of the energy charge and fixed charge including rebate/surcharge (except rebate for timely payment) is less than the minimum charge for that billing period.

104 Implementation of Demand Side Management Measurement

104.1 The Distribution Licensee shall consider the implementation of Energy Efficiency Schemes under its Capital Investment Plan.

104.2 The Distribution Licensee shall endeavour to reduce its self-consumption by implementing Energy Efficiency/Conservation measures which shall include but not limited to Distribution Transformer efficiency improvement schemes, deployment of LED bulbs and deployment of energy efficiency fans (BLDC fans, etc.), at its offices and other substations related establishments, schemes for voltage management measures and Power Factor improvement, Energy Efficiency monitoring and analytical hardware and software tools.

104.3 The Distribution Licensee shall submit its existing level of own energy consumption and Energy Conservation measure at the beginning of the Control Period and provide the trajectory for the reduction of such own energy consumption through the implementation of Energy Efficiency improvement scheme/plan under Capital Expenditure or Opex Expenditure as part of the MYT Petition along with the target of Energy Efficiency related savings, and monitoring plan.

Provided that, the Distribution Licensee shall submit its Energy Efficiency Programmes'/Scheme's Cost Effectiveness Assessment for the expected trajectory.

104.4 Distribution licensee may devise special schemes for target consumer groups to enable demand side management with approval of the Commission. Distribution Licensee may submit the scheme along with its cost benefit analysis in its MYT petition.

105 Green Energy Tariff

105.1 Green Energy Tariff shall be approved by the Commission, as a separate Tariff category i.e., as an incremental Tariff which would be per-unit charge to be paid by the consumer over and above the regular charges as per their consumer category, in line with the methodology provided by Government, if any:

Provided that the revenue from Green Energy Tariff approved by the Commission shall be in addition to the regular Tariff as approved by the Commission.

105.2 The Green Energy Tariff shall be determined based on the average power purchase cost of renewable energy, cross subsidy charges if any and service charges covering the prudent cost of the Distribution Licensee for providing green energy.

105.3 The Distribution Licensee shall submit the proposal for Green Tariff, along with all computation in the ARR / Tariff Petition. The total revenue earned under 'Green Energy Tariff' will be considered as a part of the revenue / Tariff income of the Licensee.

105.4 The total consumption of these consumers must be met by the renewable energy sources.

106 Billing and payments:

106.1 Distribution licensee shall raise electricity bill to the consumer for each billing cycle in such manner as specified in the Supply Code notified by the Commission under section 50 of the Act.

106.2 No electricity charges shall be recovered from any consumer whose supply has not been made through meter.

106.3 The consumers are liable for rebates and discount as specified under regulation 43 of these regulations and delayed payment surcharge, if payed after due date in terms of regulation 44 of these Regulations.

106.4 The net amount payable for an energy bill after considering taxes, cess, duties, etc. and adjustment of rebate / surcharges, if any, is to be rounded off to the lower value of nearest rupee or any higher multiple up to ten rupees and the differential amount is to be carried forward for adjustment against next bill on the same principle stated above. However, in case of discontinuance of power purchase agreement or discontinuance as a consumer, the licensee may bill for fractional amount for its dues payable finally.

106.5 The Electricity bill shall clearly mention the contract demand, maximum demand recorded, energy consumption during the billing period, demand charge, energy charge, FPPAS, electricity duty, government subsidy under section 65 of the Act and all rebate, discount, surcharge and penalty, as the case may be.

106.6 Notwithstanding anything contained in other regulations of the Commission if any consumer paid excess amount than the billed amount as per regulation 106.5 of these regulations through any automated mechanized collection system or cheque or draft or pay order then the excess amount will be accepted by the licensee considering that the consumer has consented to such payment. In such case the excess amount will be adjusted against the bill(s) raised during subsequent billing cycle(s).

CHAPTER – 8

POWER PROCUREMENT

107. Applicability

107.1. The Regulations contained in this Chapter shall apply to power procurement by a Distribution Licensee from a Generating Company or Trading Licensee or Distribution Licensee or from any other source through agreement or arrangement for purchase of power for distribution and supply within the State.

108. Power procurement guidelines

108.1. The Distribution Licensee shall undertake its power procurement during the year in accordance with the power procurement plan for the Control Period, which may include long-term, medium-term and short-term power procurement, approved by the Commission in accordance with Framework for Resource Adequacy Guidelines specified in Schedule-2 of these Regulations.

108.2. The Distribution Licensee shall follow the guidelines contained in this Chapter with respect to:

(a) Procurement of power under any arrangement or agreement with a term or duration exceeding seven years but not exceeding twenty-five years (i.e., long-term power procurement);

(b) Procurement of power under any arrangement or agreement with a term or duration exceeding one year but not exceeding Five years (i.e., medium- term power procurement); and

(c) Procurement of power under any arrangement or agreement with a term or duration less than or equal to one year (i.e., short-term power procurement).

108.3. All future procurement of short-term or medium-term or long-term power shall invariably be undertaken through competitive bidding in accordance with Guidelines notified by the Government of India under Section 63 of the Act and following the Modalities of Tariff Regulations notified by the Commission.

109. Power procurement plan

109.1. The Distribution Licensee shall prepare a plan for procurement of power to serve the demand for electricity in its area of supply considering the provisions of the Framework for Resource Adequacy specified in Schedule – 2 of these regulations and submit such plan to the Commission for approval:

Provided that while preparing power procurement plan, the Distribution Licensee shall ensure availability of adequate inter-state and intra-state transmission network as per STU transmission plan or highlight transmission constraints or network augmentation requirements to cater to its proposed power procurement arrangements outlined under their procurement plan.

110. Approval of long-term / medium-term power purchase agreement / arrangement

110.1. Every long-term/medium-term agreement or arrangement for power procurement, including on a Standby basis, by a Distribution Licensee from a Generating Company or Licensee or from another source of supply, and any change to an existing agreement or arrangement shall come into effect only with the prior approval of the Commission:

Provided that the prior approval of the Commission shall not be required for purchase of power from Renewable Energy sources at the generic/preferential tariff determined by the Commission for meeting its Renewable Purchase Obligation (RPO).

110.2. The Petition for approval of Power Purchase Agreement or arrangement shall include the power procurement plan for its duration.

Provided that public consultation shall not be required for adoption of tariff discovered through competitive bidding under Section 63 of the Act:

Provided further that in case of power procurement under Section 62 of the Act, public consultation as stipulated under Regulation 110.3 to 110.5 shall be followed.

110.3. The Petitioner shall submit a duly completed draft Public Notice for the Commission's approval as per the stipulated template, for publication as and when intimated by the Commission.

110.4. Upon receipt of a complete Petition accompanied by the requisite information, particulars and documents in compliance with the requirements specified in this Regulation, and fees specified in the Fees Regulations, the Petition shall be admitted and the Commission or its Secretary or designated Officer shall intimate to the Petitioner that the Petition is ready for publication.

110.5. The Petitioner shall, within three days of an intimation given to it in accordance with Regulation 110.4, publish the Public Notice in newspaper and upload in its website, in terms of clause (ii) of regulation 14 of these Regulations inviting suggestions / objections from public within 15 days.

Provided that the Petitioner shall make available a hard copy of the complete Petition to any person at such locations and at such rates as may be stipulated by the Commission.

110.6. The Commission shall consider a Petition for approval of power procurement agreement or arrangement having regard to the approved power procurement plan of the Distribution Licensee and the following factors:

(a) Requirement of power procurement under the approved power procurement plan;

(b) Adherence to a transparent process of bidding in accordance with guidelines issued by the Central Government under Section 63 of the Act or Adherence to the terms and conditions for determination of Tariff specified under Chapter-5 of these Regulations;

(c) Competitiveness of the Tariff vis-a-vis the Tariff prevalent in the market and/or Tariff discovered through competitive bidding under Section 63 of the Act;

(d) Availability (or expected availability) of capacity in the intra-State transmission system for evacuation and supply of power procured under the agreement or arrangement;

(e) Need to promote co-generation and generation of electricity from renewable sources of energy.

110.7. Upon completion of its consideration of the power procurement agreement or arrangement, the Commission shall:

(a) issue an Order approving the power procurement agreement or arrangement, subject to such modifications and conditions as it may stipulate; or

(b) reject the Petition for reasons to be recorded in writing, after giving the Petitioner an opportunity to be heard.

111. Additional power procurement

111.1. The Distribution Licensee may undertake additional power procurement during the year, over and above the power procurement plan for the Control Period approved by the Commission, in accordance with this Regulation.

111.2. Where there has been an unanticipated increase in the demand for electricity or a shortfall or failure in the supply of electricity from any approved source of supply during the Year or when the sourcing of power from existing tied-up sources becomes costlier than other available alternative sources, the Distribution Licensee may enter into additional agreement or arrangement for procurement of power.

111.3. Any variation, during the first or second block of six months of a Year, in the quantum or cost of power procured, including from a source other than a previously approved source, that is expected to be in excess of five per cent of that approved by the Commission, shall require its prior approval:

Provided that the five per cent limit shall not apply to variation in the cost of power procured on account of changes in the price of fuel for own generation or the fixed or variable cost of power purchase that is allowed to be recovered under FPPAS in accordance with Schedule-4.

111.4. Where the Distribution Licensee has identified a new short-term source of supply from which power can be procured at a Tariff that reduces its approved total power procurement cost, it may enter into a short-term power procurement agreement or arrangement with such supplier without the prior approval of the Commission.

111.5. The Distribution Licensee may enter into a short-term arrangement or agreement for procurement of power without the prior approval of the Commission when faced with emergency conditions that threaten the stability of the distribution system, or when directed to do so by the SLDC to prevent grid failure.

111.6. Within fifteen days from the date of entering into an agreement or arrangement for short-term power procurement for which prior approval is not required, the Distribution Licensee shall submit to the Commission its details, including the quantum, Tariff computations, duration, supplier particulars, method of supplier selection and such other details as the Commission may require so to assess that the conditions specified in this Regulation have been complied with.

111.7. Where the Commission has reasonable grounds to believe that the agreement or arrangement entered into by the Distribution Licensee does not meet the criteria specified in Regulations 110.2 to 110.5, it may disallow any increase in the total cost of power procurement over the approved level arising therefrom or any loss incurred by the Distribution Licensee as a result, from being passed through to consumers.

112. **Power Swapping / banking arrangement**

112.1. Distribution licensee may mange its short-term power requirement by way of banking / swapping of its surplus power with a person other than its own consumer and get that power returned during its shortfall following the conditions laid down in said agreement:

Provided that banking / swapping arrangement shall be transaction of power in barter mode:

Provided further that there may be adjustments in terms of kind for supply and return during different time of the day or season:

Provided further that the transmission and other statutory charges shall be payable based on the terms and conditions of agreement.

112.2. Distribution Licensee shall take prior approval of the Commission for any Swapping / Banking agreement if such arrangement / agreement is of more than one year. However, if the swapping/ banking arrangement is for a duration of one year or less, Distribution licensee shall submit all details of such agreement within 15 days of entering into such agreement.

112.3. The swap-in power shall be treated similar as power purchase and swap-out power shall be treated as power sale to other persons and the net swap-in and swap-out of power in any year shall be consider under power purchase cost and quantum for determination of tariff and truing-up based. The price of swapped power shall be considered at the pooled power purchase cost of the licensee, including cost of own generation, except the cost of renewable power, and shall be treated as per the following principle:

(a) When swap-in and swap-out of happens in the same year, the pooled power purchase cost during the year;

(b) When swap-in during the year happens against the swap-out during previous year, the pooled power purchase cost of the year when swap-out was made; and

(c) When swap-out is made during a year, for which power will receive in a future year, the pooled power purchase cost of the year:

Provided that the quantum of swap-in and swap-out energy shall be in terms of the swapping agreement.

112.4. The transmission charge and other statutory charges, if any shall be adjusted as a part of power purchase cost during truing up subject to prudence check by the Commission.

CHAPTER – 9

COMPUTATION OF INPUT PRICE OF COAL FROM INTEGRATED MINE

113 Applicability

113.1 The Regulations contained in this Chapter shall apply for determination of input price of coal from integrated mine(s) allocated to a Generating Company for use in one or more of its generating stations as end use. The energy charge component of the generating station shall be determined based on the input price of coal sourced from such integrated mines, in accordance with these regulations.

114 Petition for determination of Input price of coal:

114.1 The Generating Company with integrated mine(s) shall file a petition for determination of the input price of coal from the integrated mine(s)along with the MYT petition for determination of tariff for its generating station(s).

Provided that, where the commercial operation of the integrated mine commences in between a Control period, the Generating Company shall file the petition for determination of the input price of coal from the integrated mine not later than 90 days from the date of commercial operation of the integrated mine(s) in accordance with these regulations.

114.2 The generating company shall, after the date of commercial operation of the integrated mine(s) till the input price of coal is determined by the Commission under these regulations, adopt the notified price of Coal India Limited commensurate with the grade of the coal from the integrated mine(s) or the estimated price available in the investment approval, whichever is lower, as the input price of coal for the generating station.

114.3 In case of excess or short recovery of input price under regulation 114.2 of these regulations, the generating company shall refund the excess amount or recover the shortfall amount, as the case may be, with simple interest at the rate equal to the bank rate prevailing as on 1st April of the respective year of the tariff period, in a manner as may be specified by the Commission in the order of input price.

Provided that in case there is a delay in filing the Petition for determination of input price as per the timelines specified under Regulation 114.1 of these regulations, no carrying cost shall be allowed to the generating company or the mining company for such delay and in such cases the carrying cost at the bank rate from the date of filing of the Petition.

115 Components of Input Price of coal

115.1 Input price of coal from the integrated mine(s) shall be determined based on the following components:

(i) Run of Mine (ROM) Cost; and

(ii) Additional charges:

(a) crushing charges;

(b) transportation charge within the mine up to the washery end or coal handling plant associated with the integrated mine, as the case may be;

(c) handling charges at mine end;

(d) washing charges; and

(e) transportation charges beyond the washery end or coal handling plant, as the case may be, and up to the loading point:

Provided that one or more components of additional charges may be applicable in the case of the integrated mine(s), based on the scope and nature of the mining activities:

Provided further that Statutory Charges, as applicable, shall be allowed as pass-through expenses:

Provided also that the Input Price of coal determined above shall be capped to the delivered price of coal at the upper price band notified by Coal India Limited for the same Grade of coal from time to time:

Provided also that if the coal rejects generated out of the coal washery are used in own/captive generating plant, then the basic cost of coal rejects shall be considered as Nil, and actual transportation charges, subject to prudence check, shall be considered as input cost.

116 Run of Mine (ROM) Cost:

116.1 Run of Mine Cost of coal in case of integrated mine(s) allocated through an auction route under the Coal Mines (Special Provisions) Act, 2015 shall be worked out as under:

ROM Cost = (Quoted Price of coal) + (Fixed Reserve Price)

Where,

(i) The Quoted Price of coal is the Final Price Offer of coal in respect of the concerned coal block or mine, along with subsequent escalation, if any, as provided in the Coal Mine Development and Production Agreement:

Provided that additional premium, if any, quoted by the generating company during auction shall not be considered in the Run of Mine Cost;

(ii) Fixed Reserve Price is the fixed reserve price per tonne along with subsequent escalation, if any, as provided in the Coal Mine Development and Production Agreement: and

(iii) Capital cost under Regulation 118 and additional capital expenditure under Regulation 119 shall not be admissible for the purpose of ROM cost in respect of integrated mine(s) allocated through the auction route.

116.2 Run of Mine Cost of coal in case of integrated mine allocated through allotment route under Coal Mines (Special Provisions) Act, 2015 shall be worked out as under:

ROM Cost = [(Annual Extraction Cost / (ATQ or Actual production whichever is higher) + Mining Charge] + (Fixed Reserve Price).

Where,

(i) Annual Extraction Cost is the cost of extraction of coal as computed in accordance with Regulation 120 of these regulations;

(ii) Mining Charge is the charge per tonne of coal paid by the generating company to the Mine Developer and Operator engaged by the generating company for mining, wherever applicable; and

(iii) Fixed Reserve Price is the fixed reserve price per tonne along with subsequent escalation, if any, as provided in the Coal Mine Development and Production Agreement:

Provided that in case the Mining Charge includes the Annual Extraction Cost payable to the MDO, then the Annual Extraction Cost shall not be payable separately.

116.3 The generating company shall adhere to the Mining Plan for the extraction of coal on an annual basis and shall submit a certificate to that effect from the Coal Controller or the competent authority:

Provided that deviations from the Mining Plan shall be considered only if such deviations have been approved by the Coal Controller or the revised Mining Plan has been approved by the competent authority.

116.4 Run of Mine Cost of coal shall be worked out in terms of Rupees per tonne.

117 **Additional Charges**

117.1 Where crushing or transportation or handling or washing are undertaken by the generating company without engaging the Mine Developer and Operator or an agency other than the Mine Developer and Operator, additional charges shall be worked out as under:

(i) Crushing Charges = Annual Crushing Cost/Quantity;

(ii) Transportation Charges= Annual Transportation Cost/Quantity:

Provided that separate transportation charges, as applicable, shall be considered from the mine up to the washery end or coal handling plant associated with the integrated mine(s) and beyond the washery end or coal handling plant associated with the integrated mine(s) and up to the loading point, as the case may be;

(iii) Handling charges = Annual Handling Cost/ Quantity; and

(iv) Washing Charges = Annual Washing Cost/Quantity.

Where,

(a) Annual Crushing Cost, Annual Transportation Cost, Annual Handling Cost and Annual Washing Cost shall be worked out on the basis of the following components, for which the generating company shall submit the capital cost separately:

(i) Depreciation;

(ii) Interest on Working Capital;

(iii) Interest on Loan;

(iv) Return on Equity;

(v) Operation and Maintenance Expenses, excluding mining charge;

(vi) Statutory charges, if applicable.

(b) Quantity shall be the quantity of coal in a tonne crushed or transported or handled or washed, as the case may be, during the year duly certified by the Auditor.

117.2 Where crushing, transportation, handling, or washing are within the scope of the Mine Developer and Operator engaged by the generating company, no additional charges shall be admitted, as the same shall be recovered through the Mining Charge of the Mine Developer and Operator.

117.3 Where crushing, transportation, handling, or washing are undertaken by the generating company by engaging an agency other than the Mine Developer and Operator, the annual charges of such agencies shall be considered as part of the Operation and Maintenance Expenses, provided that the charges have been discovered through a transparent, competitive bidding process.

117.4 The crushing charges, transportation charges, handling charges, and washing charges shall be admitted by the Commission after a prudence check, considering charges of Coal India Limited or similarly placed coal mines or any other reference charges.

117.5 The crushing charges, transportation charges, handling charges, and washing charges shall be worked out in terms of Rupees per tonne.

118 **Capital Cost:**

118.1 The expenditure incurred, including IDC and IEDC, duly certified by the Auditor, for the development of the integrated mine(s) up to the date of commercial operation shall be considered for arriving at the capital cost.

118.2 Capital expenditure incurred shall be admitted by the Commission after a prudence check.

118.3 Capital expenditure incurred on infrastructure for crushing, transportation, handling, washing and other mining activities required for mining operations shall be arrived at separately in accordance with these regulations:

Provided that where crushing, transportation, handling or washing are undertaken by the generating company, the expenditure incurred on infrastructures of these components shall be capitalized;

Provided further that where mine development and operation, with or without any component of crushing, transportation, handling or washing, are undertaken by the generating company by engaging the Mine Developer and Operator or an agency other than the Mine Developer and Operator, the capital expenditure incurred by the Mine Developer and Operator or such agency shall not be capitalised by the generating company and shall not be considered for the determination of input price.

118.4 The capital expenditure shall be determined by considering, but not limited to, the Mining Plan, detailed project report, mine closure plan, cost audit report and such other details as deemed fit by the Commission.

118.5 In the case of integrated mine(s) which have declared the date of commercial operation prior to 1.4.2026, the capital expenditure allowed by the Commission for the period ending 31.3.2026 shall form the basis for the computation of input price.

119 **Additional Capital Expenditure:**

119.1 The expenditure, in respect of the integrated mine(s), incurred or projected to be incurred after the date of commercial operation and up to the date of achieving the Peak Rated Capacity may be admitted by the Commission, subject to a prudence check and shall be capitalized in the respective year of the tariff period as additional capital expenditure corresponding to the Annual Target Quantity of the year as specified in the Mining Plan or actual extraction in that year, whichever is higher, on following counts:

(a) expenditure incurred on activities as per the Mining Plan;

(b) expenditure for works deferred for execution and un-discharged liabilities recognized for works executed prior to the date of commercial operation;

(c) expenditure for works required to be carried out for complying with directions or orders of any statutory authorities;

(d) liabilities arising out of compliance with the order or decree of any court of law or award of arbitration;

(e) expenditure for procurement and development of land as per the Mining Plan;

(f) expenditure for procurement of additional heavy earth moving machineries for replacement, on completion of their useful life; and

(g) liabilities due to Change in Law or Force Majeure event;

Provided that in case of replacement of any assets, the additional capitalization shall be worked out after adjusting the gross fixed assets and cumulative depreciation of the assets replaced on account of de-capitalization;

Provided further that the generating company shall prepare guidelines for procurement and replacement of heavy mining equipment such as Heavy Earth Moving Machineries and share the same with the beneficiaries and submit it to the Commission along with its petition.

119.2 The expenditure, in respect of the integrated mine(s), incurred or projected to be incurred after the date of achieving the Peak Rated Capacity may be admitted by the Commission subject to a prudence check, and shall be capitalized as Additional Capital Expenditure, corresponding to the Annual Target Quantity of the respective years as specified in the Mining Plan, on following counts:

(a) expenditure incurred on activities, if any, as per the Mining Plan;

(b) expenditure for works required to be carried out for complying with directions or orders of any statutory authority;

(c) liabilities arising out of compliance with an order or decree of any court of law or award of arbitration;

(d) expenditure for procurement and development of land as per the Mining Plan; and

(e) liabilities due to Change in Law or Force Majeure events;

Provided that in case of replacement of any assets, the additional capitalization shall be worked out after adjusting the gross fixed assets, cumulative depreciation and cumulative repayment of loan of the assets replaced on account of de-capitalization.

119.3 The expenditure on the following counts shall not be considered as additional capital expenditure for the purpose of these regulations:

(a) expenditure incurred but not capitalized as the assets have not been put in service (capital work in progress);

(b) mine closure expenses;

(c) expenditure on works not covered under the Mining Plan, unless covered under clause (g) of Regulation 119.1 or clause (e) of Regulation 119.2 of these regulations;

(d) expenditure on replacement due to obsolescence of assets on account of completion of the useful life or due to obsolescence of technology if the original cost of such assets has not been de-capitalised from the gross fixed assets.

120 Annual Extraction Cost:

120.1 The Annual Extraction Cost of integrated mine(s) shall consist of the following components:

(i) Depreciation;

(ii) Interest on Loan;

(iii) Return on Equity;

(iv) Operation and Maintenance Expenses, excluding mining charge;

(v) Interest on Working Capital;

(vi) Mine closure expenses, if not included in mining charge; and

(vii) Statutory charges, if applicable.

121 Capital Structure, Return on Equity and Interest on Loan:

121.1 For integrated mine(s), the debt-equity ratio as on the date of commercial operation and as on the date of achieving Peak Rated Capacity shall be considered in the manner as specified in Regulation 30 of these regulations:

121.2 For integrated mine(s), the debt-equity ratio for additional capital expenditure admitted by the Commission under these regulations shall be considered in the manner specified in Regulation 121.1 of these Regulation.

121.3 Return on equity shall be computed in rupee terms on the equity base arrived under Regulations 121.1 and 121.2 of these regulations at the base rate of 14%.

121.4 The base rate of return on equity as per Regulation 121.3 shall be grossed up with the effective tax rate computed in the manner specified under Regulation 32 of these regulations.

121.5 Interest on loan, including normative loan, if any, determined under Regulations 121.1 and 121.2, shall be arrived at by considering the weighted average rate of interest calculated on the basis of the actual loan portfolio, in accordance with Regulation 33 of these regulations.

122 **Depreciation:**

122.1 Depreciation in respect of integrated mine(s) shall be computed from the date of commercial operation by applying the Straight-Line Method:

122.2 The value base for the purpose of depreciation shall be the capital cost of the asset admitted by the Commission:

Provided that,

(i) freehold land or assets purchased from grant shall not be considered as depreciable assets, and their cost shall be excluded from the capital cost while computing the depreciable value of the assets;

(ii) where the allotment of freehold land is conditional and is required to be returned, the cost of such land shall be part of the value base for the purpose of depreciation, subject to a prudence check by the Commission; and

(iii) leasehold land shall be amortized over the lease period or remaining life of the integrated mine(s), whichever is lower.

122.3 The salvage value of an asset shall be considered as 5% of the capital cost of the asset:

Provided that the salvage value shall be:

(i) zero for IT equipment and software;

(ii) zero or as agreed by the generating company with the State Government for land; and

(iii) as notified by the Ministry of Corporate Affairs under the Companies Act, 2013 for specialized mining equipment.

122.4 Depreciation in respect of integrated mine(s) shall be arrived at annually by applying depreciation rates or on the basis of expected useful life specified in Annexure III of these regulations:

Provided that specialized mining equipment shall be depreciated as per the useful life and depreciation rate as notified by the Ministry of Corporate Affairs under the Companies Act, 2013.

123 Operation and Maintenance Expenses:

123.1 The Operation and Maintenance Expenses in respect of integrated mine(s) shall be allowed based on the projected Operation and Maintenance Expenses for each year of the control period subject to prudence check by the Commission:

Provided that the Operation and Maintenance expenses allowed under this regulation shall be trued up annually based on actual expenses.

123.2 Where the development and operation of the integrated mine(s) is undertaken by the generating company by engaging the Mine Developer and Operator, the Mining Charge of such Mine Developer and Operator shall not be included in Operation and Maintenance Expenses under Regulation 122.1 of these regulations.

123.3 Where an agency other than Mine Developer and Operator is engaged by the generating company, through a transparent competitive bidding process, for crushing or transportation or handling or washing or any combination thereof, the annual charges of such agency shall be considered as part of Operation and Maintenance Expenses under Regulation 122.1 of these regulations, subject to a prudence check by the Commission.

124 Interest on Working Capital:

124.1 The working capital of the integrated mine(s) of coal shall cover:

(i) Input cost of coal stock for *7* days of production corresponding to the Annual Target Quantity for the relevant year;

(ii) Consumption of stores and spares, including explosives, lubricants and fuel @ 15% of operation and maintenance expenses, excluding mining charge of the Mine Developer and Operator and annual charges of the agency other than the Mine Developer and Operator, engaged by the generating company; and

(iii) Operation and maintenance expenses for one month, excluding the mining charge of the Mine Developer and Operator and annual charges of the agency other than the Mine Developer and Operator engaged by the generating company.

124.2 The rate and payment of interest on working capital shall be determined in accordance with Regulation 37 of these regulations.

125 Mine Closure Expenses:

125.1 Where the mine closure is undertaken by the generating company, the amount deposited in the Escrow account as per the Mining Plan, after adjusting interest earned, if any, on the said deposits shall be admitted as Mine Closure Expenses

Provided that,

(a) the amount deposited in the Escrow account as per the Mining Plan prior to the Date of Commercial Operation of the integrated mine(s) shall be indicated separately and shall be recovered over the useful life of the integrated mine(s) in the form of annuity linked to the borrowing rate;

(b) the amount deposited in the Escrow account as per the Mining Plan or any expenditure incurred towards mine closure shall be excluded from the capital cost for computing input price;

(c) where the expenditure incurred towards mine closure falls short of or is in excess of the reimbursement received from the Escrow account during the control period, the shortfall or excess shall be carried forward to the subsequent years for adjustments.

125.2 The amount towards mine closure shall be deposited in the Escrow account as per the Mining Plan and shall be recovered as part of the input price irrespective of the expenditure incurred towards mine closure during any of the years of the tariff period.

125.3 Where mine closure is within the scope of the Mine Developer and Operator engaged by the generating company and mine closure expenses are part of the Mining Charge of the Mine Developer and Operator, the mine closure expenses shall be met out of the Mining Charge, and no mine closure expenses shall be admissible to the generating company separately:

Provided that,

(a) the amount deposited in the Escrow account by the Mine Developer and Operator or by the generating company and any amount received from the Escrow Account against expenditure incurred towards mine closure shall not be considered for computing input price; and

(b) the difference between the borrowing cost, arrived at by considering the weighted average rate of interest calculated on the basis of the actual loan portfolio in accordance with the methodology specified in Regulation 33 of these regulations, and the amount deposited in the Escrow account and the interest received from Escrow account in a year shall be adjusted in the input price of coal or lignite of the respective year, as part of mine closure expenses, on case to case basis;

125.4 Where the mine closure is within the scope of the Mine Developer and Operator engaged by the generating company only for a part of useful life of the integrated mine(s)and the generating company undertakes the mine closure for the balance useful life, the treatment of mine closure during the period undertaken by the generating company shall be in accordance with Regulation 125.1 of these regulations and mine closure during the period undertaken by the Mine Developer and Operator shall be in accordance with Regulation 125.3 of these regulations:

Provided that the treatment of mine closure at the end of the useful life of the integrated mine(s) shall be decided by the Commission on a case-to-case basis.

125.5 The mine closure expenses worked out in accordance with this Regulation shall not be applicable in case of the integrated mine(s) allocated through an auction route under the Coal Mines (Special Provisions) Act, 2015.

126 **Determination of Input Price:**

126.1 The input price of coal shall be determined as under:

Input Price = [ROM Cost + Additional charges]

126.2 The credit arising on account of adjustment due to shortfall in overburden removal, GCV Adjustment and Non- tariff Income, if any, shall be dealt with separately in the manner specified in these regulations.

126.3 Statutory Charges, as applicable, shall be allowed.

127 **Recovery of Input Charges:**

127.1 The input charges of coal shall be recovered as under:

Input Charges = [Input Price x Quantity of coal supplied] + Statutory charges, as applicable;

Provided also that the energy charge rate based on the input price of coal does not lead to a higher energy charge rate throughout the tenure of the power purchase agreement than that which would have been obtained as per terms and conditions of the existing power purchase agreement.

127.2 The generating company shall work out the comparative energy charge rate based on the input price of coal and notified price of Coal India Limited for the commensurate grade of coal for every month from the date of commercial operation of integrated mine(s) and share the same with beneficiaries.

128 Adjustment on account of Shortfall of Overburden Removal (OB Adjustment):

128.1 The generating company shall remove overburden as specified in the Mining Plan.

128.2 In case of a shortfall or excess of overburden removal during a year, the generating company shall be allowed to adjust such shortfall or excess, as the case may be, if any, during the remaining years of the control period:

Provided that –

(a) the excess overburden as on 31.3.2029, if any, on account of the reasons not attributable to the generating company, shall be allowed to be carried forward beyond the end of the tariff period at the time of true up of the input price;

(b) the generating company shall submit the details of the adjustment of overburden at the end of the tariff period for the purpose of truing up.

128.3 Where the overburden removed in a year is less than the overburden to be removed as per the year wise schedule of extraction given in the mine plan, the adjustment on account of the shortfall of overburden removal ("OB Adjustment") for that year shall be worked out as under: -

(a) If Mine Developer and Operator is appointed: -

OB Adjustment = [Factor of adjustment for a shortfall of overburden removal during the year] x [Mining Charge during the year]

(b) If Mine Developer and Operator is not appointed: -

OB Adjustment = [Factor of adjustment for a shortfall of overburden removal during the year] x [Operation and Maintenance expenses of the mining activity during the year]

Where,

(i) Factor of adjustment for the shortfall of overburden removal during the year shall be computed as under: -

[(Annual Stripping ratio as per mining plan) - (Actual Stripping ratio based on the actual quantity of coal and overburden removed during the year)] / (1+Annual Stripping Ratio as per Mining Plan);

(ii) Annual Stripping ratio is the ratio of the volume of overburden to be removed for one unit of coal as specified in the Mining Plan.

(iii) Mining Charge is the quoted charge per tonne of coal paid by the generating company to the Mine Developer and Operator engaged by the generating company for mining, wherever applicable, without the OB adjustment as per contract with the Mine Developer and Operator.

(iv) Mining Charge and Operation and Maintenance expenses shall be in terms of Rupees per tonne corresponding to the stripping ratio and annual quantity of coal and overburden as per the mining plan.

(v) Operation and Maintenance expenses of the mining activity shall be the Operation and Maintenance expenses considered in the annual extraction cost in Regulation 120 of these regulations and excluding the Operation and Maintenance expenses related to crushing, transportation, washing, and handling in Regulation 117.1 of these regulations.

(vi) Where the generating company has engaged the Mine Developer and Operator for mining and the OB Adjustment is carried out as per the contract with the Mine Developer and Operator, the net OB adjustment as per this regulation shall be computed on the basis of the difference between the OB adjustment as per Regulation 128.3 of this regulation and the OB adjustment as per the contract of the generating company with the Mine Developer and Operator:

Provided that if the OB adjustment as per the contract with the Mine Developer and Operator exceeds the OB adjustment as per Regulation 128.3, the OB adjustment shall be treated as NIL.

128.4 The provisions of this Regulation regarding adjustment on account of shortfall or excess overburden removal, as the case may be, shall not be applicable in case of the integrated mine(s) allocated through an auction route under the Coal Mines (Special Provisions) Act, 2015.

129 Adjustment on account of shortfall in GCV (GCV Adjustment):

129.1 In case the weighted average GCV of coal extracted from the integrated mine(s) in a year is higher than the declared GCV of coal for such mine(s), no GCV adjustment shall be allowed.

129.2 In case the weighted average GCV of coal extracted from the integrated mine(s) in a year is lower than the declared GCV of coal of such mine(s), the GCV adjustment in that year shall be worked out as under:

(a) Where the integrated mine(s) are allocated through an auction route under the Coal Mines (Special Provisions) Act, 2015:

GCV Adjustment = (Quoted Price of coal + Fixed Reserve Price) X [(Declared GCV of coal - Weighted Average GCV of coal extracted in the year)/(Declared GCV of coal)]

Where,

(i) Quoted Price of coal is the Final Price Offer of coal in respect of the concerned coal Block or Mine, along with subsequent escalation, if any, as provided in the Coal Mine Development and Production Agreement:

Provided that additional premium, if any, quoted by the generating company in the auction shall not be considered; and

(ii) Declared GCV of coal shall be the GCV of coal as specified or quoted in the auction.

(b) Where the integrated mine(s) are allocated through an allotment route under the Coal Mines (Special Provisions) Act, 2015:

GCV Adjustment = [(Annual Extraction Cost/ATQ) + (Mining Charge)] X [(Declared GCV of coal – Weighted Average GCV of coal extracted in the year)/(Declared GCV of coal)]

Where,

(i) Annual Extraction Cost is the cost of extraction of coal as computed in accordance with Regulation 43 of these regulations;

(ii) Mining Charge is the charge per tonne of coal paid by the generating company to the Mine Developer and Operator engaged by the generating company for mining, wherever applicable; and

(iii) Declared GCV of coal shall be the average GCV as per the Mining Plan or as approved by the Coal Controller.

130 Adjustment on account of Non-tariff income (NTI Adjustment):

130.1 Adjustment on account of non-tariff income (NTI Adjustment) for any year, such as income from sale of washery rejects in case of integrated mine of coal and profit, if any, from supply of coal to the Coal India Limited or merchant sale of coal as allowed under the Coal Mines (Special Provisions) Act, 2015 shall be worked out as under:

NTI Adjustment = (Total Non-tariff income during the year)/(Actual quantity of coal extracted during the year)

130.2 The adjustment on account of non-tariff income worked out in accordance with this Regulation shall not be applicable in case of the integrated mine(s) allocated through an auction route under the Coal Mines (Special Provisions) Act, 2015.

Provided that in case the actual extraction is less than ATQ, no NTI adjustment shall be made till the total cost of extraction is recovered.

131 Credit Adjustment Note:

131.1 The credit arising on account of OB Adjustment, GCV Adjustment, and NTI Adjustment shall be dealt with through a Credit Adjustment Note for any year.

131.2 The Credit Adjustment Note shall be issued in favour of the specified end use generating stations on account of OB Adjustment, GCV Adjustment or NTI Adjustment, as the case may be, for that year as under:

(i) OB Adjustment for the year X Quantity of coal supplied in that year;

(ii) GCV Adjustment for the year X Quantity of coal supplied in that year; and

(iii) NTI Adjustment in the year X Quantity of coal supplied in that year.

131.3 The amount in the Credit Adjustment Note shall be adjusted against the charges of coal supplied after the date of issue of the Credit Adjustment Note. The integrated mine(s) shall prepare an annual reconciliation statement of such adjustment and furnish the same to all the end use plants and also publish the same on its website.

132 Quality Measurement:

132.1 The quality of coal or lignite supplied from the integrated mine(s) shall be measured at the loading point through third party sampling as per the guidelines and procedure specified by the Ministry of Coal, Government of India and records of such measurement of quality of coal shall be made available to the beneficiaries on demand.

133 Special Provision:

133.1 Provisions of Chapters 4 of these regulations shall not be applicable in case of integrated mine(s), except to the extent specifically provided for or referred to in this Chapter:

Provided that the financial parameters required for determination of input price of coal or lignite from integrated mine(s), if not specifically provided for or referred to in this Chapter, shall be considered as per provisions of these regulations as applicable to the coal or lignite based generating stations.

CHAPTER – 10

MISCELLANEOUS PROVISIONS

134 Savings of Inherent Power of the Commission:

134.1 Nothing in these Regulations shall be deemed to limit or otherwise affect the inherent power of the Commission to make such orders as may be necessary for ends of justice or to prevent the abuse of the process of the Commission.

134.2 Nothing in these Regulations shall bar the Commission from adopting in conformity with the provisions of the Act, a procedure, which is at variance with any of the provisions of these Regulations, if the Commission, in view of the special circumstances of a matter or class of matters and for reasons to be recorded in writing, deems it necessary or expedient for dealing with such a matter or class of matters.

134.3 Nothing in these Regulations shall, expressly or by implication, bar the Commission to deal with any matter or exercise any power under the Acts for which no Regulations have been framed, and the Commission may deal with such matters, powers and functions in a manner it deems fit.

135 Issue of Practice Direction:

135.1 Subject to the provision of the Act and these Regulations, the Commission may, from time to time, issue Orders and Practice directions with regard to the implementation of these Regulations and procedure to be followed on various matters, which the Commission has been empowered by these Regulations to direct and matters incidental or ancillary thereto.

136 Interpretation

136.1 If a question arises relating to the interpretation of any provision of these Regulations, the decision of the Commission shall be final.

136.2 If any tariff applicant fails to submit any information required to be submitted by these regulations the Commission, at its sole discretion, shall apply its best judgement to arrive at its own conclusion regarding such missing information based on prevailing norms and / or other available data, etc. and based on such methods as it may deem fit which shall be recorded through reasoned order.

137 Transparency

137.1 Wherever the Commission has issued any order in accordance with these Regulations, it shall be deemed to have acted transparently and, in a manner, envisaged under Section 86(3) of the Act.

Provided that the Commission shall maintain all the relevant records related to such order for a period of at least twelve years from the date of issue of the order and which can be accessed by public on demand in accordance with the procedure stipulated by the Commission for such purpose.

138 Power to remove difficulties:

138.1 If any difficulty arises in giving effect to any of the provisions of these Regulations, the Commission may, by a general or special order, not being inconsistent with the provisions of these Regulations or the Act, do or undertake to do things or direct the Generating Company or Transmission Licensee or SLDC or Distribution Licensee to do or undertake such things which appear to be necessary or expedient for the purpose of removing the difficulties.

139 Effect of Non-Compliance

139.1 Failure to comply with any requirement of these Regulations shall not invalidate any proceeding merely by reason of such failure unless the Commission is of the view that such failure has resulted in miscarriage of justice.

140 Power to Relax

140.1 The Commission, for reasons to be recorded in writing, may relax any of the provisions of these Regulations on its own motion or on an application made before it along with affidavit and supporting documents by an interested person.

141 Power to amend:

141.1 The Commission may, at any time, vary, alter, modify or amend any provisions of these Regulations.

142 **Repeal**

142.1 The West Bengal Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2011 issued under Notification No. 48/WBERC dated 25th April 2011 with all its amendments are hereby repealed. Notwithstanding such repeal, anything done or any action already taken under the repealed regulations, shall in so far as it is not inconsistent with these regulations, be deemed to have been done or taken under the corresponding provisions of these regulations.

SCHEDULE -1

[Clause (xxxviii) of Regulation 2.1 of these regulations]

Date and manner of Commercial Operation

1. Date of Commercial Operation of Intra-state Generating Station (InSGS)

1.1 Date of commercial operation in case of a unit of thermal InSGS shall mean the date declared by the generating company after demonstrating the unit capacity corresponding to its MCR or the Installed Capacity (IC) or name Plate Rating on designated fuel through a successful trial run and after getting clearance from the SLDC, and in case of the generating station as a whole, the COD of the last unit of the generating station:

Provided that:

a) The trial run or each repeat of trial run shall commence after a notice of not less than seven days by the generating company to the beneficiaries/buyers and SLDC:

   Provided that generating station must enter into a power purchase agreement or arrangement with its beneficiary / buyer at least one month prior to first test synchronization with the intra-state transmission system and submit the copy of the PPA to SLDC.

b) Generating company of InSGS shall certify that:

   i. Generating station meets the relevant requirements and provisions of the technical standards of CEA (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010 and Indian Electricity Grid Code (IEGC) as applicable.

   ii. Main plant equipment and auxiliary systems including balance of plant, such as fuel oil system, coal handling plant, DM plant, pre-treatment plant, fire-fighting system, ash disposal system and any other site-specific system have been commissioned and are capable of full load operation of the units of the generating station on sustained basis.

   iii. Permanent electric supply system including emergency supplies and all necessary instrumentation, control and protection systems and auto loops for full load operation of the unit have been put in service.

c) Certificates as required under clause (iii) above shall be signed by the Director/Senior officer of the generating company and a copy of the certificate shall be submitted to the SLDC before the declaration of COD. The generating company shall submit approval of the board of directors to the certificates as required under clause (iii) within a period of three months of the COD.

d) Trial run shall be carried out in accordance with paragraph 1.3 of this Schedule.

e) Partial loading may be allowed with the condition that average load during the duration of the trial run shall not be less than MCR or the Installed Capacity or the Name Plate Rating excluding the period of interruption and partial loading but including the corresponding extended period.

f) Where on the basis of the trial run, a unit of the generating station fails to demonstrate the unit capacity corresponding to MCR or installed capacity or name plate rating, the generating company has the option to de-rate the capacity or to go for repeat trial run. Where the generating company decides to de-rate the unit capacity, the demonstrated capacity in such cases shall be more or equal to 105% of de-rated capacity.

g) SLDC, shall confirm its consent or convey its concerns and objections, if any, to the generating company for declaration of COD within seven days of receiving the generation data based on the trial run.

h) If SLDC notices any deficiencies in the trial run, it shall be communicated to the generating company within seven days of receiving the generation data based on the trial run.

i) Scheduling of power from the generating station or unit thereof shall commence from 00:00 hrs after the declaration of COD to the beneficiary / buyer of the generating station.

1.2 COD in relation to a generating unit of hydro generating station including pumped storage hydro generating station, shall mean the date declared by the generating company after demonstrating peaking capability corresponding to the Installed Capacity of the generating station through a successful trial run, and after getting clearance from the SLDC, and in relation to the generating station as a whole, the COD of the last generating unit of the generating station.

Provided that:

a) The trial run or each repeat trial run shall commence after a notice of not less than seven days by the generating company to the beneficiaries / buyer and SLDC:

Provided that generating station must enter into a power purchase agreement or arrangement with its beneficiary / buyer at least one month prior to first test synchronization with the inter-state transmission system and submit the copy of the PPA to SLDC.

b) The generating company of InSGS shall certify that:

i. The generating station or unit thereof meets the requirement and relevant provisions of the technical standards of CEA (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010 and Indian Electricity Grid Code, as applicable:

ii. The main plant equipment and auxiliary systems including drainage and dewatering system, primary and secondary cooling system, LP and HP air compressor, firefighting system, etc. have been commissioned and are capable for full load operation of units on a sustained basis.

iii. Permanent electric supply system including emergency supplies and all necessary instrumentations, control and protection systems and auto loops for full load operation of the unit are put into service.

c) The certificates as required under clause (iii) above shall be signed by the Director/Senior officer of the generating company and a copy of the certificate shall be submitted to the SLDC, before the declaration of COD. The generating company shall submit approval of the Board of Directors to the certificates as required under clause (iii) within a period of three months.

d) Trial run shall be carried out in accordance with paragraph 1.3 of this Schedule.

e) Where on the basis of the trial run, a unit of the generating station fails to demonstrate the unit capacity corresponding to MCR or Installed Capacity or name plate rating, the generating company shall have the option to either de-rate the capacity or to go for repeat trial run. If the generating company decides to de-rate the unit capacity, the demonstrated capacity in such cases shall be more or equal to 110% of de-rated capacity.

f) In case a hydro generating station with pondage or storage is not able to demonstrate the peaking capability corresponding to the installed capacity for the reasons of insufficient reservoir or pond level, the COD of the last unit of the generating station shall be considered as the COD of the generating station as a whole, and it will be mandatory for such hydro generating station to demonstrate peaking capability equivalent to installed capacity of the generating station or unit thereof as the case may be, as and when such reservoir/pond level is achieved:

g) If a run-of-river hydro generating station or a unit thereof is declared under commercial operation during lean inflows period when the water inflow is insufficient for such demonstration of peaking capability, it shall be mandatory for such hydro generating station or unit thereof to demonstrate peaking capability equivalent to the installed capacity as and when sufficient water inflow is available. In case of failure to demonstrate the peaking capacity, the unit capacity shall be de-rated to the capacity demonstrated with effect from the COD.

h) If SLDC, notices any deficiency in the trial run, it shall be communicated to the generating company within seven days of receiving the generation data based on the trial run.

i) Scheduling shall commence from 00:00 hrs after the declaration of COD to the beneficiary / buyer of the generating station.

1.3 Trial Run or Trial Operation in relation to a thermal generating station or a unit thereof shall mean successful running of the generating station or unit thereof on designated fuel at MCR or installed capacity or name plate rating for a continuous period of 72 hours and in case of a hydro generating station or a unit thereof at maximum rating or installed capacity or nameplate rating for a continuous period of 12 hours:

Provided that:

a) Short interruptions, for a cumulative duration of four hours, shall be permissible, with a corresponding increase in the duration of the test. cumulative interruptions of more than four hours shall call for a repeat of trial operation or trial run.

b) Partial loading may be allowed with the condition that average load during the duration of the trial run shall not be less than maximum continuous rating, or the installed capacity or the name plate rating excluding the period of interruption and partial loading but including the corresponding extended period.

c) The trial run or each repeat of trial run shall commence after a notice of not less than seven days by the generating company to the beneficiaries and SLDC.

d) Units of thermal and hydro generating stations shall also demonstrate the capability to raise load up to 105% or 110% of this MCR or installed capacity or the name plate rating as the case may be.

2. Declaration of date of Commercial operation of Intra-state Transmission System (InSTS)

2.1 COD in relation to an InSTS or an element thereof shall mean the date declared by the transmission licensee from 00:00 hours of which an element of the transmission system is put to use in regular service after successful trial operation for transmitting electricity and communication signal from the sending end to the receiving end:

Provided that:

a) In case of InSTS executed through Tariff Based Competitive Bidding, the transmission licensee shall declare COD of the InSTS in accordance with the provisions of the Transmission Service Agreement (TSA).

b) Where the transmission line or substation is dedicated for evacuation of power from a particular generating station and the dedicated transmission line is being implemented other than through TBCB, the concerned generating company and Transmission Licensee shall endeavour to commission the generating station and the transmission system simultaneously as far as practicable and shall ensure the same through appropriate Implementation Agreement. In case the transmission line or substation dedicated to a generator is being implemented through TBCB, then matching of commissioning of the transmission line/substation and generating station shall be monitored by the appropriate Authority.

c) Where the transmission system executed by a transmission licensee is required to be connected to the transmission system executed by any other Transmission Licensee and both transmission systems are executed in a manner other than through TBCB, the Transmission Licensee shall endeavour to match the commissioning of its transmission system with the transmission system of the other licensee as far as practicable and shall ensure the same through an appropriate implementation agreement. Where either of the transmission systems or substations or both are implemented through TBCB, the progress of implementation shall be monitored by the appropriate authority as per the provisions of the TBCB guidelines or any other such document specified by the appropriate authority.

d) In case a transmission system or an element thereof is prevented from regular service on or before the Scheduled COD for reasons not attributable to the transmission licensee or its supplier or its contractors but is on account of the delay in commissioning of the concerned generating station or in commissioning of the upstream or downstream transmission system of other Transmission Licensee, or downstream distribution system of distribution Licensee, the Transmission Licensee shall approach the Commission through an appropriate application for approval of the COD of such transmission system or an element thereof.

   Provided that, the Transmission Licensee while executing the Transmission, System shall endeavour to match the construction schedule of the generator or downstream network as the case may be to avoid the idling of the assets.

   Provided further that, in case of an existing Transmission Licensee, such request may be filed under the provisions of the Tariff Regulations;

e) An element shall be declared to have achieved COD only after all the elements which are pre-required to achieve COD as per the TSA are commissioned. In case any element is required to be commissioned prior to the commissioning of the pre-required element, the same can be done if SLDC/STU confirms that such commissioning is in the interest of the power system.

f) Transmission Licensee shall submit a certificate from the Director/Senior officer of the company that the transmission line, substation, and communication system conform to the relevant provisions and Standards specified by the Central Electricity Authority.

2.2 Trial run and Trial operation in relation to a transmission system or an element thereof shall mean successful charging of the transmission system or an element thereof for 24 hours at the continuous flow of power, and communication signal from the sending end to the receiving end and with the requisite metering system, telemetry and protection system in service enclosing certificate to that effect from the SLDC.

2.3 COD in relation to a communication system or an element thereof shall mean the date declared by the Transmission Licensee from 00:00 hour of which a communication system or element thereof shall be put to use after the completion of site acceptance test, including the transfer of voice and data to the respective control centre as certified by the SLDC:

Provided that mere charging / installing/ commissioning of the transmission or communication element does not entitle it for COD, but the licensee shall ensure that the system/element has put to use in the system.

2.4 In the event of any dispute regarding the CoD declaration, the SLDC's certification shall prevail.

3. Declaration of date of Commercial operation of integrated coal mines

3.1 The date of commercial operation in case of integrated mine(s), shall mean the earliest of: -

a) the first date of the year succeeding the year in which 25% of the Peak Rated Capacity as per the Mining Plan is achieved; or

b) the first date of the year succeeding the year in which the value of production estimated in accordance with the provisions of these regulations, exceeds total expenditure in that year; or

c) the date of two years from the date of commencement of production:

Provided that on the earliest occurrence of any of the events under clauses (a) to (c) of paragraph 3.1 of this Schedule, the generating company shall declare the date of commercial operation of the integrated mine(s) under the relevant clause with one-week prior intimation to the beneficiaries of the end-use or associated generating station(s):

Provided further that in case the integrated mine(s) is ready for commercial operation but is prevented from declaration of the date of commercial operation for reasons not attributable to the generating company or its suppliers or contractors or the Mine Developer and Operator, the Commission, on an application made by the generating company, may approve such other date as the date of commercial operation as may be considered appropriate after considering the relevant reasons that prevented the declaration of the date of commercial operation under any of the clauses of paragraph 3.1 of this Schedule:

Provided also that the generating company seeking the approval of the date of commercial operation under the preceding proviso shall give prior notice of one month to the beneficiaries of the end-use or associated generating station(s) of the integrated mine(s) regarding the date of commercial operation:

Provided also that the Date of Commercial Operation in case of integrated mine shall be considered in accordance with the provisions of the Coal Mining Agreements already signed by the Generating Companies before the date of notification of these Regulations.

4. Declaration of date of Commercial operation of emission control system of InSGS

4.1 In respect of an emission control system, the date of putting the emission control system into use after meeting all applicable technical and environmental standards, certified through the Management Certificate duly signed by Competent Authority as designated by the Board of Directors of the Company, not below the level of Director of the Generating Company or Generating Business:

Provided that mere charging / installing/ commissioning of the emission control system does not entitle it for COD, but the generating station shall ensure that the system has been put to use.

5. Declaration of date of Commercial operation of element of distribution system

5.1. In respect of a distribution system or element thereof, the date of putting the element into use after successful trial run and meeting all applicable technical standards as per the State Grid Code and standards notified by the Central Electricity Authority from time to time, certified through the Management Certificate duly signed by Competent Authority as designated by the Board of Directors of the Company, not below the level of Director of the Generating Company or Generating Business:

Provided that mere charging / installing/ commissioning of the element of distribution system does not entitle it for COD, but the distribution licensee shall ensure that the element has been put to use.

Trial run and Trial operation in relation to a distribution system or an element thereof shall mean successful charging of the distribution system or an element thereof for 24 hours at the continuous flow of power, and communication signal from the sending end to the receiving end and with the requisite metering system, telemetry and protection system in service.

SCHEDULE – 2

FRAMEWORK FOR RESOURCE ADEQUACY

1. Introduction

The Resource Adequacy (RA) framework is intended to ensure that sufficient generation and demand-side capacity is tied up by the Distribution Licensees in West Bengal to reliably meet forecasted demand in a cost-effective manner. It integrates the State's planning process with the Long-Term National Resource Adequacy Plan (LT-NRAP) prepared by the Central Electricity Authority (CEA) and the Short-Term National Resource Adequacy Plan (ST-NRAP) prepared by the National Load Despatch Centre (NLDC).

2. Framework Overview and Guiding Principles

2.1. Resource Adequacy framework entails the planning of generation and transmission resources for reliably meeting the projected demand in compliance with specified reliability standards for serving the load with an optimum generation mix.

2.2. Resource Adequacy framework shall cover following important steps:

a) Demand assessment and forecasting;

b) Generation resource planning;

c) Procurement planning; and

d) Monitoring and compliance.

2.3. The distribution licensee shall develop and prepare Long-Term Distribution Resource Adequacy Plan (LT-DRAP) for a 10-year horizon on rolling basis, a Medium-term Resource Adequacy Plan (MT_DRAP) for a 5-year horizon on rolling basis and a Short-Term Distribution Resource Adequacy Plan (ST-DRAP) for one year, in accordance with the conditions outlined under these Regulations.

2.4. The distribution licensees, State Transmission Utility and State Load Despatch Centre shall provide requisite information and data including demand forecasts for a period up to 10 years to various Agencies to enable Central Electricity Authority and Grid India/NLDC to undertake LT-NRAP and ST-NRAP studies, respectively, as per CEA RA Guidelines.

2.5. The Resource Adequacy framework for the State shall be implemented in alignment with the "Guidelines for Resource Adequacy Planning Framework for India" issued by the Ministry of Power, Government of India, and any subsequent amendments thereof.

3. Demand Assessment and Forecasting

3.1. Demand assessment and forecasting is an important step for Resource Adequacy assessment. For short-term it shall entail at least hourly or sub-hourly assessment and forecasting of demand within the distribution area of distribution licensee using comprehensive input data and policies and drivers and scientific mathematical modelling tools. For medium-term, it shall entail hourly load assessment and forecasts, while for long-term, it shall entail monthly peak/off-peak load assessment and forecasts along with category wise energy forecasts.

3.2. The distribution licensee shall be responsible for the assessment and forecasting of demand (MW) and energy (MWh) within its own control area including partial open access consumers.

3.3. Distribution licensee shall be responsible for providing the category wise consumption data and assessed consumption data of class of consumers such as agricultural, domestic etc. to various agencies such as SLDC and/or STU for purpose of state level demand forecasts. The distribution licensee shall submit the category wise consumption information of pervious financial years and any other information as may be required by SLDC/STU by 21st April of each year as per format to be prescribed by SLDC/STU.

3.4. The distribution licensee shall determine the load forecast for each consumer category for which the Commission has determined separate retail tariff.

3.5. The distribution licensee shall determine the load forecast for a customer category by adopting any of the following and/or combination of following methodologies:

a) compounded average growth rate (CAGR);
b) end use or partial end use;
c) trend analysis;
d) Auto-regressive integrated moving average (ARIMA);
e) AI including machine learning, ANN techniques;
f) econometric (specifying the parameters used, algorithm, and source of data); and

g) any other methodology prescribed by the Authority in its "Guidelines for Medium and Long-Term Demand Forecast".

3.6. The distribution licensee may use Electric Power Survey (EPS) projections as base and/or any other methodologies other than the above-mentioned after recording the merits of the method. Further, distribution licensee should use best fit of various methodologies for the purpose of demand/load forecast taking into consideration probabilistic modelling approach for various scenarios (viz. most probable, business as usual, aggressive) as outlined under Clause 3.15.

3.7. For the purposes of deciding the load forecast for a customer category and the methodology to be used for load forecasting of a customer category, the distribution licensee must conduct statistical analysis and shall select the method for which standard deviation is lowest and R-square is highest.

3.8. The distribution licensee shall utilize state-of-the-art tools, scientific and mathematical methodologies, and comprehensive database such as but not limited to weather data, historical data, demographic and econometric data, consumption profiles, impact of policies and drivers etc. as may be applicable to their control area.

3.9. The distribution licensee may modify the load obtained on either side, for each customer category, by considering the impact for each of the but not limited to the following activities. The impact shall be considered by developing trajectories for each of the activities based on the economic parameters, policies, historical data, and projections for the future.

a) demand-side management;
b) open access;
c) distributed energy resources;
d) DSM and demand response measures;
e) electric vehicles;
f) tariff signals;
g) changes in specific energy consumption,
h) increase in commercial activities with electrification
i) increase in number of agricultural pump sets and its solarization
j) changes in consumption pattern from seasonal consumers
k) availability of supply; and
l) policy influences such as 24X7 supply to all customers, LED penetration, efficient use of fans/appliances, increased use of appliances for cooking/heating applications, electrification policies, distributive energy resources, storage, and policies,

which can impact econometric parameters, impact of national hydrogen mission. For each policy, a separate trajectory should be developed for each customer category.

3.10. The distribution licensee may take into consideration any other factor not mentioned in clause 3.9 after recording the merits of its consideration.

3.11. The medium-term load profile of the customer categories for which load research has been conducted may be refined on the basis of load research analysis. A detailed explanation for refinement conducted must be provided.

3.12. The summation of energy forecast (MWh) for various consumer categories upon adjusting for captive, prosumer, and open access load forecast, as obtained as per clauses 3.4 to clause 3.11, as the case may be, shall be the load forecast for the licensee.

3.13. The licensee shall calculate the load forecasts (in MWh) by adding a loss trajectory approved by the Commission in the latest tariff order. In the absence of the loss trajectory as approved by the Commission for the planning horizon, an appropriate loss trajectory stipulated by State or National policies shall be considered with a detailed explanation.

3.14. The peak demand (in MW) shall be determined by considering the average load factor, load diversity factor, seasonal variation factors for the last three years and the load forecasts (in MWh) obtained in clause 3.13. If any other appropriate load factor is considered for future years, a detailed explanation shall be provided.

3.15. The distribution licensee shall conduct sensitivity and probability analysis to determine the most probable demand forecast. The distribution licensee must also develop long-term and medium-term demand forecasts for possible scenarios, while ensuring that at least three different scenarios (most probable, business as usual, and aggressive scenarios) are developed.

3.16. Short term (Hourly/Sub-hourly) Demand Forecast and Aggregation at State:

3.16.1. The distribution licensee shall develop a methodology for at least hourly or sub-hourly demand forecasting and shall maintain a historical database.

3.16.2. For the purpose of ascertaining hourly load profile and for assessment of contribution of various customer categories to peak demand, load research analysis shall be conducted and influence of demand response, load shift measures, time of use shall be factored in by distribution licensee with inputs from SLDC. A detailed explanation for refinement conducted must be provided.

3.16.3. The distribution licensee shall utilize state-of-the-art tools, scientific & mathematical methodologies and comprehensive data such as but not limited to weather data, historical data, demographic and econometric data, consumption profiles, policies and drivers etc. as may be applicable to their control area.

3.17. The distribution licensee shall produce hourly or sub-hourly as may be decided by the Commission from time to time, 1-year short-term (ST), 5-year medium-term and 10-year long-term (LT) forecasts on a rolling basis and submit to SLDC by 30th April of each year for the ensuing year(s).

3.18. SLDC with inputs from STU and based on the demand estimates of the distribution licensees of the State, shall estimate, in different time horizons, namely long-term, medium term and short term, the demand for the entire State duly considering the diversity of the State.

3.19. SLDC shall aggregate demand forecasts by distribution licensees, consider the load diversity, congruency, seasonal variation aspects and shall submit state-level aggregate demand forecasts (MW and MWh) to the Authority and NLDC and RLDC by 31st May of each year for the ensuring year(s).

4. Generation Resource Planning:

4.1. Generation resource assessment and planning is the second step after demand assessment and forecasting and entails assessment of the existing and contracted resources considering their capacity credit and identification of incremental capacity requirement to meet forecasted demand including planning reserve margin.

4.2. Generation resource planning shall entail the following steps:

(a) capacity crediting of generation resources;

(b) assessment of planning reserve margin; and

(c) ascertaining resource adequacy requirement and allocation for obligated entities within control area (state / distribution licensee).

4.3. The distribution licensee shall map all its contracted existing resources, upcoming resources, and retiring resources to develop the existing resource map in MW for the long term and medium term.

4.4. The mapping shall include critical characteristics and parameters of the generating machines, such as heat rate, auxiliary consumption, ramp-up rate, ramp-down rate, etc., for thermal machines; hydrology and machine characteristics, etc., for hydro machines; and renewable resources, their Capacity factors (CUFs), etc. for renewable resource–based power plants to be considered in the resource plan. All the characteristics and parameters with their values for each generating machine considered shall be provided in the resource plan. Some of the important parameters that would be considered for this resource characteristic assessment shall include but not limited to following:

a) Name of the plant (with location, district, geo-coordinates)
b) Installed Plant Capacity (MW) (existing and planned)
c) Heat rate of thermal generating stations
d) Auxiliary consumption (MW)
e) Maximum and Minimum generation limits (MW)
f) Ramp up and Ramp down rate (MW/min)
g) Minimum up and down time including start-up time, shut-down time etc.
h) Plant availability factor (%)
i) Average capacity utilisation factor for past 3 years (%)
j) Historical outage rates and planned outage rates
k) Installed Capacity and generation profile of renewable energy generation resources
l) Under-construction / contracted capacity with likely date of commissioning
m) Planned Retirement of capacity or Renovation of capacity with timelines
n) Transmission expansion plans with timelines
o) Evacuation arrangements with timelines for RE generation resources

4.5. Constraints such as penalties for unmet demand, forced outages, spinning reserve requirements, and system emission limits as defined in State and Central electricity grid codes, planning criteria of CEA and emission norms specified by the Ministry of Environment Forest and Climate Change shall be identified and enlisted.

5. Capacity Credit of Generation Resources:

5.1. The distribution licensee shall compute Capacity Credit (CC) factors for their contracted generation resources by applying the net load-based approach as outlined under Clause 5.2 of this Regulation. The five-year average of the Capacity Credit (CC) factor for each type of the contracted generation resource for the recent five years on a rolling basis shall be considered as Capacity Credit factor for the purpose of generation resource planning.

5.2. The Net Load based approach/methodology for determination of Capacity Credit (CC) factors for generation resources (including wind and solar) shall be adopted as under:

a) For each year, the hourly recorded Gross Load for 8760 hours (or time-block) shall be arranged in descending order.

b) For each hour, the Net Load is calculated by subtracting the actual wind or solar generation corresponding to that load for 8760 hours (or time-block) and then arranged in descending order similar to Step 1.

c) The difference between these two load duration curves represents the contribution of capacity factor of wind generation or solar generation, as the case may be.

d) Installed capacity of wind or solar generation capacity is summed up corresponding to the top 250 load hours.

e) Total generation from wind or solar generation corresponding to these top 250 hours is summed up.

f) Resultant CC factor is (Total Generation for top load 250 hours)/(Installed RE Capacity for top load 250 hours), as per formula below:

$$CC\ Factor = \frac{Sum\ of\ RE\ Generation\ for\ top\ x\ hours}{Sum\ of\ RE\ Capacity\ for\ top\ x\ hours}$$

g) The process for CC factor determination shall be undertaken for each year for duration of past five-years and the resultant CC is the average of CC values of past 5 years.

5.3. For the purpose of Inter-state contracted RE generation or intra-state RE resources, contribution of CC factor for the RE or generation resource where such resource is located into grid (viz. inter-state or intra-state, as the case may be) as contracted by the distribution licensee shall be considered. For this purpose, CC factors as specified by Authority or the Commission shall be considered.

5.4. CC factors for hydro generation resources shall be computed based on water availability with different CC factors for run-of-the-river hydro power projects and dam-based/storage-based hydro power projects. CC for thermal resources shall be computed based on coal availability and forced outages.

5.5. The computation for CC factor for the storage technology shall be determined using Top Net Load Hours approach or such other methodology as may be prescribed by the Authority.

5.6. The distribution licensee shall share CC factors for their contracted resources along with justification for its computations with SLDC along with its short-term, medium-term and long-term forecasts by 30th April of each year for the ensuing year(s).

5.7. SLDC shall calculate state-specific CC factors considering the aggregate State Demand and State Net Load and contracted generation resources available in the State and shall submit such CC factor information to the Authority and NLDC and RLDC by 31st May of each year.

6. Assessment of Planning Reserve Margin:

6.1. Planning Reserve Margin (PRM) as a percentage of peak load represents the excess generation resource or planning reserve required to be considered for the purpose of generation resource planning.

6.2. Such Planning Reserve Margin (PRM) factor (for example, 10%) shall be based on the reliability indices in terms of Loss of Load Probability (LOLP, for example, 0.2%) and Normalized Energy Not Served (NENS, for example, 0.05%) as may be specified by the Authority or by the Commission, and the same shall be considered by entities in their planning for resource adequacy requirement and generation resource capacity planning.

6.3. The distribution licensee shall include a PRM as specified by the Authority or Commission, as the case may be. In the absence of any guidelines from the Commission, the distribution licensee can consider suitable planning reserve with proper justification, which will be subject to approval of the Commission, provided that the PRM adopted by the distribution licensee shall be at least equal to or greater than the PRM adopted by the Authority. The value of planning reserve considered shall be stipulated in the resource plan along with justifications.

6.4. The capacity planning by the distribution licensee and State level resource adequacy planning by STU/MSLDC shall factor in PRM while developing state- level Integrated Resource Plan.

7. Ascertaining Resource Adequacy Requirement (RAR) and its Allocation for Control Area:

7.1. Upon applying CC factors as determined under clause 5 of these regulations and determining adjusted capacity for contracted generation resources (existing and planned), the sum of such adjusted contracted generation capacity (existing and planned) over a time axis of at least one hour, or 15 minutes interval as may be decided by the Commission from time to time, but not more than one hour, shall form the resource map of the distribution licensee.

7.2. The distribution licensee shall subtract the resource map developed in clause 7.1 from the demand forecast developed in clause 3.14 to identify the resource gap. The resource gap in terms of RA compliance for the distribution licensee for the long-term, medium-term, and short-term shall be developed in the manner as specified in these Regulations.

7.3. The distribution licensee shall conduct sensitivity and probability analysis to determine the most probable resource gap. The distribution licensee shall also develop long-term and medium-term resource gap plans for possible scenarios, while ensuring that at least three different scenarios (most probable, business as usual, and aggressive) are developed.

7.4. Based on most probable scenario, the distribution licensee shall undertake development of Long-term Distribution Resource Adequacy Plan (LT-DRAP), Medium-term Distribution Resource Adequacy Plan (MT-DRAP) and Short-term Distribution Resource Adequacy Plan (ST-DRAP) exercise by 31st August of each year to meet RA target requirement.

7.5. Long-term National Resource Adequacy Plan (LT-NRAP) published by CEA and Short-term National Resource Adequacy Plan (ST-NRAP) published by NLDC shall act as guidance for the distribution licensee(s) for undertaking the Resource Adequacy exercises.

7.6. The Central Electricity Authority will publish the Long-term National Resource Adequacy Plan (LT-NRAP) to determine the optimal Planning Reserve Margin (PRM) requirement at the national level for ensuring reliable supply targets. The report will also include the optimal generation mix for the next 10 years thereby ensuring compliance with Resource Adequacy Requirements while meeting national demand at least cost basis. Further, the report will feature capacity credits for different resource types on a national basis and prescribe the State contribution towards the national peak demand.

7.7. NLDC will publish a one-year look-ahead Short-term National Resource Adequacy Plan (ST-NRAP) report which will include parameters such as demand forecasts, resource availability based on under-construction status of new projects, planned maintenance schedules of existing stations, station-wise historic forced outage rates and decommissioning plans.

7.8. Based on the allocated share in national peak provided in LT-NRAP for the State, STU/SLDC shall allocate each distribution licensee's share in the state peak within 15 days of the publication of LT-NRAP based on average of the percentage share in the state coincident peak demand (CPD) and percentage share in the state non-coincident peak demand (NCPD).

7.9. The distribution licensee based on the above allocation shall accordingly plan to contract the capacities to meet its Resource Adequacy Requirement (RAR) while ensuring that its own peak demand plus PRM is met.

7.10. The distribution licensee shall keep a minimum 75% of RAR through Long-term contracts, a minimum 10% of RAR through Medium–term contracts, and the rest to be met through Short-term contracts:

Provided that, the contracts mix may be periodically reviewed by the Commission:

Provided further that power procurement through Day-Ahead Market (DAM), shall not be considered towards the contribution for meeting RAR.

7.11. RA requirement planning of the state shall be done with reference to national coincident peak and of distribution licensees with reference to average of share in state coincident peak demand (CPD) and share in state non-coincident peak demand (NCPD), to optimize requirement of incremental capacity addition through annual rolling plan. Mid- term review of state RA requirement planning shall be conducted to check for events of slippages by states, if any.

7.12. While planning RA requirement, the distribution licensee shall duly factor in the allocation of RA requirement to the distribution licensee as may be suggested by the STU/SLDC, as the case may be, based on average of share in state coincident peak demand (CPD) and share in state non-coincident peak demand (NCPD) for LT-RA, MT-RA and ST-RA.

7.13. Distribution license shall submit its Long-term Resource Adequacy plan (LT-DRAP) for 10 years horizon to CEA by 30th September each year for vetting based on the national database. Distribution Licensee shall also share its LT-DRAP, MT-DRAP and ST-DRAP with the SLDC and STU, so that SLDC/ STU can accommodate it with their system/ network augmentation plan. Distribution Licensee shall accommodate the modification suggested by STU/ SLDC/ CEA, if any, in their plan.

7.14. Distribution Licensee shall submit its MT-DRAP, ST-DRAP along with the vetted LT-DRAP by CEA, before the Commission on yearly basis for approval by 30th November of each year. The Commission shall approve LT-DRAP, MT-DRAP and ST-DRAP of the distribution licensees by 30th December of each year for the ensuring year(s) incl. annual rolling plans, as the case may be, upon taking into consideration various scenarios as well as allocation of Resource Adequacy requirement allocated to the State/distribution licensee based on its contribution to the National/state peak respectively as determined by Authority/NLDC/RLDC and STU/SLDC, as the case may be. LT-DRAP shall be for purposes of planning and consistency with national framework.

8. Power Procurement Plan

8.1. Procurement planning shall consist of (a) determining the optimal power procurement resource mix, (b) deciding on the modalities of procurement type and tenure, and (c) engaging in the capacity trading or sharing to minimize risk of resource shortfall and to maximize rewards of avoiding stranded capacity or contracted generation.

8.2. For identification of the optimal generation procurement resource mix considering renewable purchase obligation, optimization techniques and least-cost modelling shall be employed in order to avoid stranding of assets. The distribution licensee shall engage in adoption of least cost modelling and optimization techniques and demonstrate the same in its overall power procurement planning exercise.

8.3. The distribution licensee may contract power through State Generating Stations / Central Generating Stations / Independent Power Producers (IPPs) / Captive Power Plants (CPPs) / Renewable Power Plants including Co-Generation Plants / Central Agencies / State Agencies / Intermediaries / Traders / Aggregators / Power Exchanges or through bilateral agreements / Banking arrangements with other distribution licensees, Over-the-counter (OTC) or any other platform recognized and approved by the Central Electricity Regulatory Commission and any other sources as may be approved by the Commission under Section 62 or Section 63 of the Act in compliance with competitive bidding guidelines, subject to the conditions specified under Modalities of Tariff Regulations.

8.4. The distribution licensees shall identify the generation resource mix and also procurement strategy in long-term, medium-term, and short-term horizon and seek approval of the Commission as a part of its power procurement approval:

Provided that The distribution licensee shall keep a minimum 75% of RAR through Long-term contracts, a minimum 10% of RAR through Medium–term contracts, and the rest to be met through Short-term contracts:

Provided further that the Distribution Licensee shall consult the State Transmission Utility at the time of preparation of the power procurement plan, to ensure consistency of such plan with the transmission system plan.

8.5. The distribution licensee shall demonstrate to the Commission 100% tie-up for the first year, a minimum 90% tie-up for the second year and a minimum of 80% tie-up for the third year to meet the requirement of their contribution towards meeting state peak. For subsequent two years, the distribution licensee shall also furnish a plan to meet estimated requirement of their contribution to meet state peak for the Commission's approval.

8.6. Assessment through Annual Rolling Plan shall ascertain incremental capacity addition requirement through LT/MT/ST upon factoring in existing and planned procurement initiatives of the distribution licensee.

8.7. The distribution licensee shall contract capacities by 30th November of each year and submit the Annual Rolling Plan to STU and SLDC by 31st December of each year for ensuring year(s).

8.8. STU / SLDC, as the case may be shall submit state-level aggregated plan to RLDC/NLDC by 31st January of each year for the ensuing year(s).

9. Sharing of Capacity

9.1. The distribution licensee shall duly factor in the possibility of short-term capacity sharing while preparing the Resource Adequacy plan and optimally utilize the capacity available within the state through competitive sharing arrangements or other mechanisms, and then use the platform for inter-state capacity sharing or trading mechanism if created by the Central Commission or other mechanisms as the case may be and optimize the capacity costs as far as possible:

Provided that all generators and distribution licensees shall declare extra capacity available indicating quantum and period on shared portal, accessible to all stakeholders:

Provided further that for the purpose of this regulation SLDC shall develop the share portal and its detailed procedure within six months from notification of these regulations.

9.2. The distribution licensee shall submit information about contracted capacity to the SLDC and the STU for compliance verification.

9.3. Distribution licensee shall seek approval of the Commission for the Power Procurement as well as Annual Rolling Plan i.e. MT-DRAP and ST-DRAP. For approval of such plans, the Commission shall seek inputs from STU/SLDC to ensure consistency with the state-level aggregation carried out by STU/SLDC.

10. Approval of Power Purchase Agreement

10.1. Any new Capacity arrangement/tie-up shall be subject to the prior approval of the Commission in terms of provisions of Chapter-8 of these Regulations.

11. Monitoring and Compliance

11.1. Monitoring and Reporting: Based on the MT-DRAP and ST-DRAP, STU and SLDC shall communicate the state-aggregated capacity shortfall to the Commission by 15th September of each year for the ensuring year(s) and advise the distribution licensees to commit additional capacities. The Commission shall approve RA plans by 30th September of each year.

11.2. **Treatment for shortfall in RA Compliance**: Distribution licensees shall comply with the RA requirement and in case of non-compliance, appropriate non- compliance charge shall be applicable for the shortfall for RA compliance.

11.3. For shortfall in RA compliance, SLDC shall levy and collect non-compliance charge from the concerned Distribution Licensee.

11.4. The rate of Non-compliance charges shall be equivalent to 1.1 times the Marginal Capacity Charge (Rs/kW/month) or 1.25 times the Average Capacity Charge (Rs/kW/month) whichever is higher, as approved by the Commission for the power procurement by concerned distribution licensee under its ARR/Tariff Order for the relevant financial year, unless separately specified by the Commission.

11.5. The distribution licensee shall not be allowed to recover such non-compliance charge as part of its ARR.

12. Institutional Strengthening

12.1. The Distribution Licensee shall, within six (6) months of the notification of these regulations, establish and adequately staff a dedicated Resource Adequacy Planning Cell under its Area Load Despatch Centre.

12.2. This cell shall be responsible for all activities mandated under this chapter, including demand forecasting, capacity credit calculation, portfolio optimization modelling, and preparation of the LT-DRAP, MT-DRAP and ST-DRAP. It shall be equipped with the necessary software tools and shall submit an annual report to the Commission on its activities and capacity building initiatives.

SCHEDULE – 3

Guidelines for Capital Expenditure Approval Framework

1. Background

1.1. Section 61 of the Electricity Act, 2003 mandates the State Electricity Regulatory Commission, while specifying the terms and conditions for determination of tariff, shall be guided by the factors which encourage competition, efficiency, economical use of the resources, good performance and optimum investments, to ensure safeguarding of consumers' interest and also recovery of the cost of electricity in a reasonable manner, at the same time.

1.2. Further, Section 181 of the Electricity Act, 2003 mandates the State Electricity Regulatory Commission to make Regulations consistent with the Act and the Rules generally to carry out the provisions of the Act. Capital Investment undertaken by the regulated entities is amongst the most vital factor impacting the approval of revenue requirement and tariff determination process entrusted to the State Electricity Regulatory Commission by the Act. Accordingly, it is utmost important to ensure regulating the Capital Investment Schemes proposed by the regulated entities in a transparent and consistent manner to promote competition, efficiency, economical use of the resources, good performance and optimum investments.

1.3. In terms of regulation 5.10 of the West Bengal Electricity Regulatory Commission (Licensing and Conditions of Licence) Regulations, 2013 the Commission in the Tariff Regulations, has to specify the approval mechanism of capital investment plans and the procedure and limits of major investments in capital items by the Transmission and Distribution Licensees. For Generating company, these guidelines will be applicable to only those Generating Stations / Units whose tariff is determined by Commission under Section 62 of the Act.

1.4. Based on the above, the Commission has specified these ‘Guidelines for Capital Expenditure Approval Framework’ to be followed by all regulated entities whose tariff is being determined by the Commission under these Regulations, setting up the principles for investment approval for proposed Capital Investment as well as the approval to be granted to the final completed cost.

2. Submission of Capital Investment Plan

2.1. Generation Company or Transmission Licensee or Distribution Licensee, as the case may be, shall submit Capital Investment Plan as a part of its Perspective Plan along with Multi Year Tariff Petition and Mid-term Review petition, as the case may be, outlining the major schemes proposed for each year of the Control Period for approval of the Commission.

2.2. The five-year Capital Investment Plan shall be submitted by the entities as a part of their Multi-Year Aggregate Revenue Requirement for the entire Control Period. The capital investment plans should be internally consistent and reconcilable with other relevant proposals and supporting information presented in the submission such as demand projections, network reliability and design criteria. The capital investment plan shall show separately, on-going projects that will spill over into the control Period, and new projects (along with justification) that will commence in the control Period but may be completed within or beyond the control period. The capital investment plan shall contain the scheme details, justification for the work, capitalization schedule, capital structure and cost benefit analysis (wherever applicable).

2.3. In case of Generation and Transmission related investments, the Capital Investment Plan shall be planned considering that the schemes shall be capitalised with a 3 to 5 years horizon, and a 1 to 3 years horizon for Distribution.

2.4. The capital investment plan shall provide the following details for each scheme:

(a) Safety Requirement in Compliance with the applicable rules, regulations, standards, codes, etc;
(b) Necessity for the investment;
(c) Bill of Quantity and Bifurcation of Capital investment wherever applicable;
(d) Project Cost Estimation and Cost Benefit Analysis;
(e) Evaluation of Alternatives and Constraints;
(f) Risk Analysis;
(g) Project Monitoring Mechanism;
(h) Technical Justification and demand projections wherever applicable;
(i) Quantifiable Customer Benefits

2.5. Generation Company or Transmission Licensee or Distribution Licensee, as the case may be, shall adopt an objective driven approach for capex planning. These regulated entities should also set clear long-term, medium-term and short-term objectives and categorize capital investment schemes based on the objectives that the schemes intend to achieve. Proper Competitive bidding process shall be followed throughout the preparation of Capital Investment Plan. The proposed investment scheme shall also comply with the applicable rules, regulations, standards, codes, etc.

2.6. The Commission will develop a web-based portal for submission, review, approval and monitoring of the Capital Investment Schemes above the threshold limit.

2.7. Till development of the web-based portal as mentioned above, the submission, review, approval and monitoring shall be undertaken through physical and / or submission as may be specified by the Commission.

2.8. Utilities shall provide quarterly updates on the status of implementation of all approved DPR Schemes. Updates shall be submitted through the web-based portal and in physical form till development of such portal.

2.9. Failure to provide updates may result in penalties as determined by the Commission.

3. **Requirement of In-Principle Approval**

3.1. Generation Company or Transmission Licensee or Distribution Licensee, as the case may be, shall make an application to the Commission for obtaining prior approval of the Commission for each scheme involving major investments, which shall also be considered as DPR schemes, and demonstrate to the satisfaction of the Commission that:

(a) There is a need for the proposed 'major investment', which is being proposed to undertake;

(b) the economic, technical and environmental aspects of all viable alternatives to the proposed investment in capital asset scheme has been examined; and

(c) the Generation company or Transmission Licensee or Distribution Licensee, as the case may be, has explored all possible avenues and is sourcing funds in the most efficient and economical manner.

3.2. For the purposes of Clause 3.1(a), the term "major investment" means any planned investment in or acquisition of assets or facilities, the cost of which, when aggregated with all other investments or acquisitions (if any) forming part of the same overall transaction, equals or exceeds the following limits**:**

a) Generating Station or Unit of a Generating Company – Rs. 10 Crore or 0.5% of approved closing GFA of previous trued-up year, whichever is lower;
b) Transmission Licensee – Rs. 20 Crore;
c) Distribution Licensee – Rs. 10 Crore or 0.5% of approved closing GFA of previous trued-up year, whichever is lower;

3.3. Any one or a combination of the following objectives needs to be fulfilled by the proposed Capital Investment Schemes for being considered for In-Principal approval:

a) Development of new infrastructure to meet the forthcoming load requirements;
b) Augmentation of the capacity of existing projects or systems;
c) Enhancement in the transformation capacity of existing infrastructure;
d) Revenue optimization from existing and new assets;
e) Improvement in the operational efficiency of existing systems;
f) Replacement of assets account of damage of asset or obsolescence of technology;
g) Replacement of assets that have completed their Useful Life and are beyond repair;
h) Improvement in the quality and reliability of power supply;
i) Renovation and Modernisation for life extension of the entire project;
j) Compliance with environmental norms and regulations;
k) Enhancement in the appropriate cyber security measures as per Government policy and regulatory guidelines.

Provided that Renovation and Modernisation Schemes for Generation business and Transmission business shall be in accordance with relevant Guidelines notified by the CEA:

Provided further that, in case capital cost has been incurred towards replacement or upgradation of any existing assets, the original cost of the replaced asset shall be reduced and decapitalized from the Capital Cost.

Provided also that the cost of premature replacement / shifting of the assets because of projects of other utilities such as road widening, removal of obstacles and freeing space for other project, shall be recovered / recoverable from the concerned infrastructure development agency.

3.4. In case of asset replacement, it shall not be approved merely because the asset has completed its Useful Life as specified in the applicable Regulations. The Applicant will have to submit adequate justification for the asset replacement based on aspects such as residual life as certified by a competent agency, performance degradation based on diagnostic testing, and assets beyond repair.

3.5. The certificate from a competent agency, as referred above, shall be required only in cases where the replacement of assets is premature without completion of regulated life or obsolescence of the technology, and there are alternatives to replacement under capital expenditure.

3.6. Replacement of assets shall be the last resort and not the first priority. While proposing assets for replacement, only essential scope shall be considered to optimize the project cost.

3.7. No in-principle approval is required for Non-DPR Schemes where capital expenditure is less than the limit specified in paragraph 3.2 above:

Provided that Capital Investment Scheme proposed by the Petitioner under Non-DPR Schemes should be for entire independent system and the Scheme should not be submitted in parts:

Provided further that, the amount of capitalization proposed under all non-DPR Schemes by a Generating Company or Transmission Licensee or Distribution Licensee, for any year shall not exceed 20% of the cumulative amount of capitalisation proposed by it under DPR Schemes in that year or 0.5% of its GFA, whichever is lower:

Provided further that prior investment approval is not required for 100% grant funded schemes.

3.8. In case of emergency works, regulated utility shall mandatorily intimate the Commission within 15 days from the start of the work and shall submit the DPR complete in all respects for post-factor approval of the Commission, if the capital investment falls within the limits specified in 3.2 above. In the petition, the nature of emergency and the reason of non-submission in advance shall be clarified.

3.9. For the purpose of these guidelines, a Capital Investment Scheme means any nonrecurring capital expenditure programme for the acquisition, construction or improvement of a permanent facility in a particular sector (i.e. Generation, Transmission, Distribution, General, etc.).

3.10. The Generating Companies or Transmission Licensee shall submit separate Capital Investment Schemes for each Generating Unit/Station or Transmission Scheme as appropriate.

3.11. Distribution Licensees shall submit separate application for approval of Capital Investment for each Distribution Zone or specific region or area or specific to activity, except for Schemes related to metering, centralised purchase such as Distribution Transformers, Cable, and other equipment, which may be submitted for the Distribution Licensee as a whole:

Provided further that the Distribution Licensees may club Distribution Schemes partly funded by Government grants such as DDUGJY, IPDS, RDSS, SAUBHAGYA, etc.

3.12. Further, the Capital Investment Schemes proposed by the Applicant shall be for entire independent system including any associated upstream/downstream works, and the Schemes shall not be submitted in parts Capital Investment Schemes of a value below the values specified by the Commission and shall be considered as Non-DPR Schemes:

4. **Submission of Detailed Project Report (DPR) for In-principle Approval:**

4.1. For those Capital Investment Schemes which equals or exceeds the threshold limit as specified in Clause 3.2 above, the regulated entity should submit DPR for the Commission's In-principle Approval with a broad Cost-Benefit Analysis.

4.2. The DPR must clearly outline the scope and objectives of the proposed Scheme and explain how the Scheme meets the evaluation criteria mentioned in the same.

4.3. The DPR must be accompanied by such information, particulars and documents to support the details contained in the plan including technical reports, design criteria, supplier/contractor quotations, term sheets of financing agencies etc., as may be required to enable assessment of the nature involved in ex-ante, In-principle approval and shall provide an Overview of the Scheme. DPR shall include:

a) Name of the Scheme
b) Scope and Objective;
c) Technical specifications of scope of the work;
d) Estimated Cost and basis of same
e) Date of approval by Competent Authority;
f) Capital Structure;
g) Capitalization Schedule;
h) Financing Plan, including identified sources of investment;
i) Physical targets;
j) Cost-benefit analysis;
k) Checklist of documents.
l) Any other relevant documents based on the nature of work

4.4. All Transmission and Distribution Schemes shall be prepared considering the followings:
a) overall system requirement, existing infrastructure and ongoing capital investment projects, and not only for specific area, in order to ensure against over-investment in certain districts/areas;
b) Urgency of the capital investment in terms of scope for and impact of phasing and/or deferment, as well as implications of not undertaking the capital investment;
c) Activity-wise Single Line Diagram of relevant areas;
d) Detailed route survey for Transmission Schemes;
e) any other Technical and Financial Justification Documents required by the commission based on the case

4.5. The DPR should also specify the following:

a) methodology by which the Scheme's progress can be monitored and corrective action to be taken in case of any deviation from the schedule including geotagging, etc.;

b) methodology for verification of Scheme being put to use and projected percentage utilization of the assets for the first five years after commissioning of proposed capital investment;
c) details of required upstream/downstream arrangements, if any, for realisation of the benefits from the proposed Scheme, and their status and programme for their completion;
d) list and status of Statutory Clearances/Approvals required to execute the project;
e) Physical and financial constraints, if any, in execution of the Scheme, and identification of all possible delays and their causes and proposed mitigation measures.

4.6. In case of installation of new generating station or extension of capacity of any existing generating station, in addition with the above the Generating Company or Licensee has to submit the copy of Power Purchase Agreement or Power Purchase Arrangement, as the case may be, documents of coal linkage / sourcing, copies of statutory clearances, approval of CEA or competent authority and such other documents as found necessary.

4.7. The Commission shall also lay down formats for submission of DPR so as to facilitate the assessment.

4.8. Generating Company, Transmission Licensee or Distribution Licensee shall file the petition for in-principle approval of DPR Schemes once in every quarter of each financial year, on of before 30th April, 31st July, 31st October and 31st January respectively:

Provided that the petition for in-principle approval of DPR Schemes shall be filed under a single covering letter, along with one consolidated cost benefit impact and tariff impact for all the Capital Investment Schemes:

Provided further that any petition filed after 30th April, 31st July, 31st October, and 31st January, respectively, shall be considered along with the next filing, as applicable:

Provided also that the petitioner shall make the payment towards fees in the office of the Commission as specified in the WBERC Fees Regulations as amended from time to time, for every Scheme for which the petitioner is seeking in-principle approval and revised approval, as applicable.

4.9. The Commission shall admit the petition within 7 days of the submission, only upon receipt of a complete feasibility report accompanied by the requisite additional information, particulars and documents in compliance with the requirements specified in this guideline.

4.10. After admission of the petition the Commission shall intimate the utility within 5 days for publication of notice in terms of regulation 14 of these regulations, inviting suggestions/ objections from stakeholders. Stakeholders have to submit their suggestions / objections within 14 days from the date of publication.

5. **Approval Process:**

5.1. The Commission shall adopt the following checkpoints for the Approval of Capital Investment of schemes:

A. In-principle Approval prior to undertaking the capital investment against DPR Schemes;
B. Final Approval of completed cost of asset after put to use.

Provided that for new generating plant or extension project of existing generating station, the Generating Company or licensee shall take a second stage investment approval from the Commission prior to placement of order(s) after conducting due competitive bidding, mentioning the project cost on the basis of agreed price with the supplier(s) and contractor(s) and mentioning the final details of the technical parameters as submitted during the 'In-principle' clearance. Generating Company or licensee, shall submit any remaining documents of statutory clearance, if not able to submitted during the 'in-principle' clearance stage.

5.2. In-principle Approval: The Commission shall initially grant 'In-principle approval of Capital Investment of Schemes after examining the necessity and techno-commercial feasibility of Capital Investment Scheme containing the detailed information about the proposed scope of work in scheme so as to execution of work could be taken up by Power Utilities.

5.3. Evaluation Criteria to be adopted by the Commission for 'In-Principle' Approval: The initial approval of the Commission before implementation of capital works schemes is an In-Principle approval mainly keeping in view the following:

(a) Safety Requirement

(b) Necessity of Investment
(c) Bill of Quantity and Project Costing Estimation
(d) Cost Benefit Analysis
(e) Evaluation of Alternatives and Constraints
(f) Risk Analysis
(g) Project Monitoring Mechanism & Execution Timeline
(h) Technical Justification
(i) Quantifiable benefits

5.4. All Capital Investment Schemes of a value exceeding 250 Crore shall be first scrutinized by the Capital Investment Scrutiny Committee to be set up by the Commission through separate order by the Commission for scrutiny of such proposal:

Provided that an external expert or agency may be co-opted by the Committee from time to time for necessary inputs and expertise.

5.5. While submitting the DPR, Generation Company or Transmission Licensee or Distribution Licensee, as the case may be would need to address the above evaluation criteria for the proper justification for approval of Capital Investment plan. The illustrative explanation for such justification is as provided below:

(1) Safety Requirement: To ensure that all necessary obligations are being met as per Electricity Act, 2003, and all other applicable Rules, Regulations and to highlight any statutory violation along with steps taken to safeguard the same, provided appropriate sanctions of competent authority and clearances from concerned departments/ministries is available.

(i) Whether the scheme is necessary to discharge the duty/obligation as per Electricity Act, 2003 or to meet any other statutory or safety requirement. (If the scheme is likely to result in violation of any provision of the Electricity Act, 2003, and/or any other applicable Rules, Regulations the same should be mentioned clearly and the safeguards for this should also be brought out.)

(ii) Whether the proposal is accompanied with appropriate sanctions of the competent authority and statutory and safety clearances from concerned departments/ministries, wherever such sanctions or clearances are required? The Commission may grant the conditional approval if only the forest clearance is to be obtained but the work shall not commence until the clearance is received.

(2) Necessity for the Investment: To determine if it's needed to make the Capital Investment in infrastructure to meet current and future needs, to check if the equipment is operating as intended, or extend the lifespan of existing assets for a more reliable system and improved efficiency as may be applicable. It is an important step to ensure if the facility is being created as a multiple use asset or an existing asset can fulfil the function being served by the proposed utility.

(i) Whether equipments proposed to be replaced are operating close to their rated capacities and equipments are required to reduce the load on the existing equipments to prolong its life, to increase the reliability of the system and to facilitate the creation of back up facility during scheduled maintenance operation?

(ii) Whether the capital investment is necessary to set-up the infrastructure required to meet normal load growth or to reach new Consumers?

(iii) Whether the investment is necessary for increasing administrative efficiency which in turn will result in better services to the consumers?

(iv) Whether the investment results in duplication of existing infrastructure (owned by any other utility, or that utility itself)?

(v) Are the assets or facilities being created multiple use assets which can be used in some other business, and to what extent?

(vi) Whether it meets at least the near future demand growth projections?

(vii) Any other reason?

(3) Bill of Material (BoM) and Project Costing estimation: This is a necessary step to ensure the correctness of the cost etc. and to maintain consistency amongst the proposed technical drawings, single line diagrams, Grid maps of the concerned areas and

applicable standards from competent authorities such as Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010 are adhered to. The BoM, hence, needs to be complete in all aspects such as equipment/asset quantities, description, specification, supplier information etc.

(i) Whether the complete documentation of Bills of Material (BoM) is done containing specific components, assemblies and sub-assemblies for a project. Utility shall ensure key element checks as outlined below in preparation of BoM:

- **Completeness:** BoM should be complete in all respect relating to quantity, part description, item specification, supplier information, etc.
- **Consistency:** Information in BoM should be consistent with that provided in engineering drawings and design files.
- **Correctness:** Correctness should be ensured by avoiding errors such as obsolete data and incorrect part numbers, quantity, etc.

(4) Cost Benefit Analysis: The proposal should quantify the benefits of the Capital Investment scheme such as reduction in losses, access to new consumers, reliability of supply, and any other benefit. This step acts as an important safeguard to ensure the Return on Investment is justifiable from the consumer's point of view. The utilities should also provide the methodology used for calculating the benefits to ensure consistency across the utilities.

(i) Utility shall carry out Benefit to Cost Analysis for all projects being taken up irrespective of the value of works. It may use a combination of formal financial criteria, such as Net present value (NPV), Internal rate of return (IRR) and Benefit to Cost Ratio.

(ii) The proposal shall bring out quantifiable physical benefits such as Reduction in transmission / distribution losses, Reduction in the load on existing system, Improvement in voltages, Reliability of supply, and any other benefits.

(iii) Projects can provide a wide range of benefits—economic, social, and reliability— to the consumers. Social and

Government driven schemes need not be subject to investment analysis.

(iv) Is the proposed investment a necessity for the conduct of business, or is it a luxury, the burden of which is being passed on to consumers. Or the Return on Investment justifiable from the consumer's point of view.

(v) The utilities shall also propose the methodology of measurement of the benefits accruing out of the investment.

(5) Evaluation of Alternatives and Constraints: To ensure that the Petitioner has considered alternative approaches, the Petitioner should justify the basis on which proposed scheme has been selected out of the alternatives considered to ensure the least cost plan with maximum benefit has been proposed. For example, assessment of the fact that whether the scheme can be carried out under Operational Expenditure Scheme or O&M Budget. This step also needs the Applicant to ensure that all the constraints in proposed scheme have been envisaged and mitigation methods are prepared.

(i) Whether other alternative schemes have been considered. (If so, the basis on which the proposed scheme has been selected out of several alternatives considered by the Utilities will have to be mentioned.)

(ii) If the proposed investment includes repair and maintenance of substations then since the expenses of repairs are already provided for in the O&M expenses and, therefore, justification for claiming these expenses under capital investment must be clearly brought out.

(iii) The alternatives should be analysed in terms of their respective cost and benefits, to finalize the least cost plan with maximum benefits.

(6) Risk Analysis: A scheme level detailed risk analysis matrix is necessary to be submitted depending on the value and criticality of the project. The risks to consider may include but are not limited to design, procurement, financing, RoW, construction, etc. This ensures alternatives and associated risks have been evaluated during the planning process.

(i) Whether the utility had assessed risk associated with a project and all its alternatives during planning phase. (A risk management plan/ matrix/ strategy to mitigate such risk and its impact, should address these risks in all phases of the project- viz, design, approvals, financing, procurement, construction, completion and have mitigation strategies for various risks.)

(ii) A detailed risk evaluation matrix should be prepared at a scheme level or project level depending on the value, scale and criticality of the project.

(iii) Whether the utility had ensured the evaluation of risks for the minor works as well. (The DPR/Estimate copies should include a minimum of a write-up on the possible issues/risks that the Field Officer foresees in implementation of the said project.)

(7) Project Monitoring Mechanism & Execution Timelines: Any foreseeable delay due to certain project risks must be incorporated within the DPR during the planning phase to account for scheduling, pre-award activities and avoid time and cost over-runs. Documents such as PERT Chart/Gantt Chart etc. showing completion stages and to assess whether alternative plans for delays have been evaluated.

(i) Whether the utility has developed standard timelines for execution of different types of capital works. (It can be included in the form of Bar/PERT charts in the DPR outlining the schedule of project pre-award activities, supply, erection and commissioning schedules etc.)

(ii) Whether any delay foreseen due to certain project risks, have been identified in the planning stage and appropriate duration have been factored in the standard timelines and incorporated in the agreements with contractors and vendors?

(8) Technical Justification: The step ensures that the scheme meets the design criteria in keeping with prevailing norms and standards and that the useful life of assets has been assumed correctly. This also ensures that sufficient steps have been taken to accommodate for the projected growth in demand and rate of obsolescence of technology.

(i) Whether the scheme conforms to the planning criteria of the Central Electricity Authority?

(ii) Whether the scheme meets design criteria in keeping with prevailing norms and standards?

(iii) Whether the replacement of old equipment is necessary and, if so, whether the existing equipment has outlived its normal life span?

(iv) Is the Useful life of the equipment reasonable?

(v) What is the average rate of technology obsolescence for that equipment?

(vi) Does the investment increase the efficiency in Operations & Maintenance and improve reliability of Supply?

(vii) Whether the capacity planned is commensurate with demand growth?

(viii) Whether the scheme is being executed in different phases over a period of time. (If so, the schemes completed and the schemes now proposed to be taken up will have to be clearly mentioned.)

(9) Quantifiable Benefits: A detailed scrutiny of the fact that the perceived benefits are quantifiable and verifiable and necessary data, justification and documentary evidence with methodology adopted for calculation has been specified.

(i) What are the broad quantitative and qualitative benefits?

(ii) What is the likely net impact on consumers over a 5-year period considering the recurring costs and broad Cost-Benefit analysis?

(iii) Is the Return on Investment justifiable?

(iv) What are the results / benefits observed so far, if applicable?

5.6. ‘In-Principle’ Approval: At the stage of ‘In-Principle’ approval, the cost proposed by the Utility is on estimated basis. The Commission shall give 'In-Principle' approval to the schemes, indicating estimated cost scope and objective of work, funding arrangement, time frame for phasing out expenditure, list of major items with their ratings and quantities, etc. It's to be noted that the In-principle should not be considered as the final approval for the ARR purpose, and the scheme will be open for scrutiny during the tariff determination process/ARR review, particularly in the context of actual cost incurred, scope and objectives achieved, etc.

5.7. The Commission shall give the 'In-principle' clearance within 60 days of admission of submission, if the Commission found the proposed scheme prudent as per the aspects mentioned in these guidelines. The petition shall be deemed approved after 60 days of submission, if not rejected as per Regulation 5.8 of these regulations or communicated otherwise by the Commission.

5.8. The Commission may reject the application for in-principle approval if it finds that the scheme is not in accordance with the objectives set forth these Guidelines or if the DPR is found to be lacking in material particulars. The reasons for such rejection shall be communicated to the Applicant in writing.

5.9. In case the Utilities fail to initiate the work, including tendering process if any, within one year from the date of issuance of 'In-Principle' clearance order, the approval shall be deemed to be cancelled. The Utility will have to re-submit the fresh DPR for the scheme, in order to obtain revised 'In-Principle' clearance of the Commission with justification for the delay in scheme initiation.

5.10. Revised in-principle approval of Capital Investment may be accorded by the Commission in case a Generating Company or Transmission Licensee or Distribution Licensee files the same, only under exceptional circumstances related to land unavailability or feasibility of the Scheme being adversely affected due to force majeure events:

Provided that revised in-principle approval may be granted only for change in scope of work due to site conditions or change in norms, and not due to change in rates.

5.11. Final Approval of completed cost of DPR scheme:
The final approval of capital outlay consequent to implementation of a scheme will be granted at the time of True-up (post capitalization) after a diligent and proper prudence check and verification of the actual cost, actual quantity of material used, proper implementation of the

scheme and after verifying that all legal clearances like Environment clearance, Electrical Inspector's permission etc, have been obtained. The final approval of capital cost consequent to implementation of a scheme shall take into consideration the prices emerging through the competitive bidding process and the quantities for all major items as indicated in "in-principle" approvals of various schemes. The Utility, seeking final approval, shall furnish copies of the purchase orders, sales invoices, delivery challans, etc. of the manufacturer relating to goods for which capitalization has been proposed. The Utility shall maintain a record of all 'In-Principle' approvals granted by the Commission, including the quantities of major items contained therein. The Commission shall require the utility to link the quantities contained in purchase orders/work orders placed by them with the quantities contained in various 'In-Principle' approvals granted by the Commission from time-to-time.

5.12. An indicative list of parameters for prudence check during the final approval are as follows:

a) Variation in quantities actually used with respect to quantities considered in the scheme;
b) Variation between approved and completed cost of equipment and phasing of investment;
c) Whether all procurement of materials and service followed transparent competitive bidding;
d) Whether the Applicant has submitted all the essential data and justifications;
e) Whether the stated objectives as submitted at the time of in-principle approval have been achieved;
f) Date of asset Capitalisation and whether the asset has been put to use, geotagged and included in the FAR;
g) Difference between the scheduled date of commercial operation or put to use considered in the in-principle agreement vs actual date of put to use;
h) Actual Cost benefit Analysis;
i) Variation in funding of capital investment.

5.13. For distribution or transmission scheme, where a tangible part of the DPR scheme has been put to use in a particular year, not less than 20% of the project cost, the licensee shall claim for part capitalization along with the truing up petition. The Commission may admit the part capitalization subject to 5% withheld for adjustment along with the final capital cost after completion of the entire scheme and closure of contract(s):

Provided that the Commission shall compute the IDC of such project based on the project milestone approved in the in-principle approval.

5.14. For new generating station or extension of existing generating station, petition for final project cost shall be submitted after cut-off date on closure of the contract(s).

5.15. Any mismatch between amount of Capitalisation claimed in the True-up Petition with the capitalisation reported in Completion Reports may lead to disallowance of the excess capitalisation, unless found justified after prudence check.

6. **Project Monitoring:**

6.1. The Utility shall institute a project management and monitoring team (PMO) with a composition of technical and finance personnel to effectively track, monitor and review the progress of projects undertaken.

6.2. The Utility shall keep a quarterly record of all the works executed and categorized. The same shall be available for review for the Commission at any point of time. An Indicative list of information need to be maintained are as following**:**

a) Date of publication of bid;
b) Date of award;
c) Zero date for the project;
d) Date of completion of the work;
e) Estimated value of the work as per the estimate/DPR;
f) Amount Capitalized;
g) Design of Capex Guidelines;
h) Date of Capitalization;
i) Delay in Capitalization;
j) Reasons for any delay in Capitalization.

6.3. A summary report should be submitted to the Commission for all completed projects, ongoing projects along with its details with focus on time overruns, cost overruns and other related issues on a quarterly basis.

6.4. Status report must mention the status of implementation of each scheme in term of expenditure incurred and item wise physical progress achieved during the implementation of the scheme.

7. Prudence Check for Approval of Completed Cost of Non-DPR Schemes

7.1. The final approval of completed cost of Non-DPR Schemes after the asset is put to use may be sought along with the claim for true-up, in accordance with these Regulations.

7.2. The Commission shall allow capitalisation of Non-DPR schemes based on the prudence check, subject to the cap against capitalisation of Non-DPR schemes specified in these Regulations.

8. Consequences of not obtaining In-Principle Clearance

8.1. Failure to obtain the 'In-Principle' clearance of the Commission, the Commission may disallow the recovery of such expenditure / cost in the tariff order or pass such other orders, as the Commission may consider appropriate.

8.2. Based on the information provided by the Utility as per the process as specified in the previous paragraphs, the Commission may, disallow recovery of such cost in the tariff order or pass such other orders, as the Commission may consider appropriate.

9. Standard Cost Sheet to be maintained by the Transmission Licensees and Distribution Licensees

9.1. Transmission and Distribution Licensees shall prepare and submit the Standard Cost Sheet to the Commission within three (3) months of notification of these Regulations, for all capital items procured by them based on latest rates discovered through competitive bidding with the supporting documents or latest Board approved standard rates, as applicable, which may be validated by Officers of the Commission.

9.2. Transmission Licensee and Distribution Licensee shall update the Standard Cost Sheet annually by 31st May based on the latest discovered rates and submit the same to the Commission.

9.3. The Standard Cost Sheet shall be the reference document for estimation of item-wise capital cost by the Applicant while seeking in-principle approval of DPR Scheme:

9.4. Provided that the Scheme shall be executed as per the price discovered through the competitive procurement process.

9.5. For exceptional items not listed in Standard Cost Sheet, the Applicant shall provide budgetary quotations from multiple vendors for estimation of capital cost of such items or procurement costs for earlier periods as a reference.

9.6. The Applicants shall ensure that Standard Cost Sheet is maintained for the major equipment contributing to around 60 percent to 70 percent of the total Scheme cost, comprising inter-alia, cables, conductors, transformers, meters, transmission towers, switchgears, GIS, SCADA, Protection Systems, etc.

9.7. If the Applicants do not submit the updated Standard Cost Sheet, the Commission shall approve the Scheme as per the available Standard Cost Sheet without any escalation:

9.8. Provided that the cost data in the Standard Cost Sheet shall not be more than two years old.

10. **Web Portal**

10.1. The Commission will develop an online portal for submission, review and approval of DPR schemes.

10.2. Till development of such online portal by the Commission, the Utilities shall file for in principle approval of DPR Schemes once in every quarter of each financial year and any filings done after the end of financial quarter will be considered along with the filings of the next quarter.

11. **Miscellaneous**

11.1. The Commission retains the power to add, vary, alter, amend, change, modify or otherwise substitute the above guidelines or any part thereof in such manner and at any time the Commission may consider appropriate. The Utility shall not claim any vested right in the facility given by these guidelines, if the Commission decide to add, modify, alter, change etc the guidelines or any part thereof.

11.2. Without prejudice to the above the Commission may at any time direct the Utility to comply with such further or other conditions as the Commission may consider appropriate for undertaking investments.

SCHEDULE -4

Fuel and Power Purchase Adjustment Surcharge (FPPAS)

1. Fuel and Power Purchase Adjustment Surcharge (FPPAS) means the increase in cost of power, supplied to consumers, due to change in Fuel cost, power purchase cost and transmission charges with reference to cost of supply approved by the Commission.

2. FPPAS shall be calculated and billed to consumers, automatically, without going through regulatory approval process, on a monthly basis, according to the formula, prescribed by the Commission in this Schedule, subject to true up, on an annual basis:

   Provided that the automatic pass through shall be adjusted for monthly billing in accordance with this Schedule;

   Provided further that the Distribution Licensee shall make monthly submissions of the detailed FPPAS computations, duly supported by the documentary evidence and certified by a practicing Chartered Accountant, justifying such computations, along with details its charging and recovery from the consumers.

3. FPPAS shall be computed and charged by the Distribution Licensee, in $(n+2)^{th}$ month, on the basis of actual variation, in cost of fuel and power purchase and Interstate Transmission Charges for the power procured during the n^{th} month. For example, the FPPAS on account of changes in tariff for power supplied during the month of April of any financial year shall be computed and billed in the month of June of the same financial year:

   Provided that in case the Distribution Licensee fails to compute and charge FPPAS within this timeline, except in case of any force majeure condition, its right for recovery of costs on account of FPPAS shall be forfeited and in such cases, the right to recover the FPPAS determined during true-up shall also be forfeited.

4. The Distribution Licensee may decide, FPPAS or a part thereof, to be carried forward to the subsequent month in order to avoid any tariff shock to consumers, but the carry forward of FPPAS shall not exceed a maximum duration of two months and such carry forward shall only be applicable, if the total FPPAS for a Billing Month, including any carry forward of FPPAS over the previous month exceeds twenty per cent of variable component of approved tariff.

5. The carry forward shall be recovered within one year or before the next tariff cycle whichever is earlier and the money recovered through

FPPAS shall first be accounted towards the oldest carry forward portion of the FPPAS followed by the subsequent month.

6. In case of carry forward of FPPAS, the carrying cost calculated on simple interest basis at the rate bank rate, as specified under these regulations, shall be allowed till the same is recovered through tariff and this carrying cost shall be trued up in the year under consideration.

7. Depending upon quantum of FPPAS, the automatic pass through shall be adjusted in such a manner that,

   i. If FPPAS ≤ 5%, 100% cost recoverable of FPPAS by Distribution Licensee shall be levied automatically using the formula.

   ii. If FPPAS > 5%, 5% FPPAS shall be recoverable automatically as per item (i) of paragraph (7) above. 90% of the balance FPPAS shall be recoverable automatically using the formula and the differential claim shall be recoverable after approval by the Commission during true up.

8. The revenue recovered on account of pass through FPPAS by the Distribution Licensee, shall be trued up annually for the year under consideration.

9. In case of excess revenue recovered for the year against the FPPAS, the same shall be recovered from the Distribution Licensee at the time of true up along with carrying cost to be charged at 1.20 times of the carrying cost rate specified in regulation 8.6 of these regulations and the under recovery of FPPAS shall be allowed during true up, to be billed along with the automatic FPPAS amount.

   Explanation:- For example, in the month of July, the automatic pass through component for the power supplied in May and additional FPPAS, if any, recoverable after true up for the month of April in the previous financial year, shall be billed.

10. The Distribution Licensee shall submit such details, in the stipulated formats, of the variation between expenses incurred and FPPAS recovered, and the detailed computations and supporting documents, as required by the Commission, during true up of the normal tariff.

11. To ensure smooth implementation of the FPPAS mechanism and its recovery, the Distribution Licensee shall ensure that its billing system is updated to take this into account and a unified billing system shall be implemented to ensure that there is a uniform billing system irrespective of the billing and metering vendor through

interoperability or use of open source software as available.

12. The Distribution Licensee shall publish all details including the FPPAS formula, calculation of monthly FPPAS and recovery of FPPAS (separately for automatic and approved portions) on its website and archive the same through a dedicated web address.

13. Formula for Computation of FPPAS:

$$\text{Monthly FPPAS for the N}^{th}\text{ month (\%)} = \left(\frac{(A-B)\ x\ C + (D-E)}{[\{Z\ x\ (1-L/100)\}\ x\ ABR]}\right)\ x\ 100$$

Where,

Nth month means the month in which billing of FPPAS component is done. This FPPAS is due to changes in tariff for the power supplied in (n-2)th month;

A is Total units procured in (n-2)th Month (in kWh) from all Sources including Long- term, Medium-term and Short-term Power purchases (To be taken from the bills issued to Distribution Licensees) (ex-bus);

B is sale of power from all Sources to other than consumers in (n-2)th Month (in kWh) = (to be taken from provisional accounts to be issued by State Load Dispatch Centre by the 10th day of each month);

C is incremental Average Power Purchase Cost (including the change of fuel cost) = Actual average Power Purchase Cost (PPC) from all Sources in (n-2)th month (Rs./ kWh) (computed) - Projected average Power Purchase Cost (PPC) from all Sources (Rs./ kWh) - (from tariff order);

D = Actual inter-state and Intra-State Transmission Charges in the (n-2)th Month, (From the bills by Transmission licensees to the distribution licensees) (in Rs);

E = Base Cost of Transmission Charges for (n-2)th Month. = (Approved Transmission Charges in the tariff order/12) (in Rs);

Z = [{Actual Power purchased from all the sources outside the State in (n-2)th Month. (in kWh) x (1 — Interstate transmission losses in % /100) + Power purchased from all the sources within the State (in kWh)} x (1 — Intra-State losses in %/100) — B] in kWh;

ABR = Average Billing Rate for the year as approved by the Commission in the tariff order (in Rs/kWh);

L (in %) = Target Distribution Losses as approved by the Commission in the tariff order;

Intra-state transmission Losses (in %) as approved by the Commission in tariff order.

Note:

(i) The Power Purchase shall include sourcing power from own generation.

(ii) The Power Purchase Cost shall exclude any charges on account of Deviation Settlement Mechanism.

(iii) Pumping energy for PSP, if any, shall be considered under sale other than consumer.

(iv) The transmission charge shall exclude any charge towards transmission deviation charge.

(v) Other charges which includes ancillary services and security constrained economic despatch shall not be included in FPPAS and shall be adjusted through the true up approved by the Commission.

SCHEDULE - 5

OPERATING NORMS

A. **Norms for Coal Fired Thermal Generating Stations**

A1. **Norms of Gross Station Heat Rate (SHR), Normative Annual Plant Load Factor (NAPLF), Normative Annual Plant Availability Factor (NAPAF), Auxiliary Energy Consumption (AEC) and Secondary Fuel oil consumption for existing generating stations:**

Name of the Generating Station	Unit Size	SHR	NAPLF	NAPAF	AEC	Secondary Fuel Oil consumption
		(Kcal/kwh)	(%)	(%)	(%)	(ml/kWh)
CESC:						
Budge Budge TPS	3x250 MW	**2470**	**80**	**85**	**9.00**	**0.50**
Southern TPS	2x67.5MW	**2900**	**80**	**85**	**9.00**	**1.00**
WBPDCL:						
Bakreswar TPS	5x210 MW	**2470**	**80**	**85**	**9.00**	**0.50**
Kolaghat TPS (Unit III to VI)	4x210 MW	**2700**	**70**	**75**	**9.60**	**1.00**
Bandel TPS (Unit-I)	1x60 MW	**3050**	**65**	**70**	**10.40**	**1.00**
Bandel TPS (Unit V)	1x215 MW	**2430**	**80**	**85**	**8.50**	**1.00**
Santaldih TPS (Unit V & VI)	2x250 MW	**2425**	**80**	**85**	**9.00**	**0.50**
Sagardighi TPS (Unit I & II)	2x300 MW	**2345**	**80**	**85**	**9.00**	**0.50**
Sagardighi TPS (Unit III & IV)	2x500 MW	**2424**	**80**	**85**	**5.25**	**0.50**
DPL:						
Unit-VII	1x 300 MW	**2345**	**80**	**85**	**8.5**	**0.50**
Unit-VIII	1x250 MW	**2425**	**80**	**85**	**9.0**	**0.50**
IPCL:						
Dishergarh TPS (New)	1x12 MW	**3300**	**80**	**85**	**10.00**	**0**
Hiranmaye Energy Ltd.	2x150 MW	**2477.15**	**80**	**85**	**10.50**	**0.50**
Haldia Energy Ltd.	2x300 MW	**2345**	**80**	**85**	**9.00**	**0.50**
Adhunik Power and Natural Resources Ltd.	2x270 MW	**2387**	**80**	**85**	**9.00**	**0.50**

Provided that a generating station shall be compensated for degradation of Station Heat Rate, Auxiliary Energy Consumption and consumption of additional secondary fuel due to backdown on direction of SLDC or its beneficiary. The compensation for the Station Heat Rate and Auxiliary Energy Consumption shall be worked out in terms of energy charge rate

(1) Degradation of Gross Station Heat Rate

Sr. No	Unit loading as a % of Installed Capacity of the Unit	Increase in SHR (for sub-critical units) %	Increase in SHR (for super-critical units) %
1	65 - < 70	5.1	4.1
2	60 - < 65	6.1	4.9
3	55 - < 60	7.6	6.0
4	50 - < 55	9.2	7.1
5	45 - < 50	11.3	8.3
6	40 - < 45	13.8	9.9

(2) Degradation of Auxiliary Energy Consumption

Sr. No	Unit loading as a % of Installed Capacity	% degradation in AEC admissible
1	60 - < 70	1.8
2	50 - < 60	2.5
3	40 - < 50	3.2

(3) Compensation for Secondary Fuel Oil Consumption

The additional compensation for secondary fuel oil consumption shall be permissible over and above seven (7) starts/ stop in a year for the generating station under Unit Shutdown. For the purpose of compensation, the secondary fuel oil consumption per start up shall be considered based on the following norms or actuals, whichever is lower:

Unit Size (MW)	Secondary Fuel Oil Consumption per start up (KL)		
	Hot	Warm	Cold
Upto 350 MW	20	40	60
500 MW	30	60	100
660 MW	45	75	130

Additional specific secondary fuel oil consumption of 0.2 ml/kWh shall be provided for units operating below 55%-unit loading.

Provided that the procedure for stipulating the mechanism to work out the compensation for degradation of heat rate, auxiliary energy consumption and secondary fuel oil consumption due to part load operation and multiple start and stop of units of the generating station shall be issued by the SLDC separately within 31.03.2026 with the approval of the Commission.

A2. **Norms for New Generating Stations and Generating Stations not covered under A1 above:**

(i) **Normative Annual Plant Availability Factor (NAPAF):** 85%

(ii) **Normative Annual Plant Load Factor (NAPLF):** 80%

(iii) **Gross Station Heat Rate (SHR) for Coal-based Thermal Generating Stations:**

For 200-300 MW Sets: 1.05 X Design Heat Rate (kCal/kWh)

For 500 MW Sets and above: 1.045 X Design Heat Rate (kCal/kWh)

Where the Design Heat Rate of a generating unit means the unit heat rate guaranteed by the supplier at conditions of 100% MCR, zero per cent make up, design coal and design cooling water temperature/back pressure.

Provided that depending upon the pressure and temperature ratings of the units, the maximum design turbine cycle heat rate and minimum design boiler efficiency shall be as per the table below:

Pressure Rating (Kg/cm2)	150	170	170	247	247	260	270	270
SHT/ RHT (^{0} C)	535 / 535	537 / 537	537 / 565	537 / 565	565/593	593/593	593/593	600/600
Type of BFP	Electrical Driven	Turbine Driven	Turbine Driven	Turbine Driven	Turbine Driven	Turbine Driven	Turbine Driven	Turbine Driven
Max Turbine Heat Rate (kCal/ kWh)	1955	1950	1935	1900	1850	1814	1810	1790
Min. Boiler Efficiency (%)								
Sub-Bituminous Indian Coal (%)	86.00	86.00	86.00	86.00	86.00	86	86.50	86.50
Bituminous Imported Coal (%)	89.00	89.00	89.00	89.00	89.00	89.50	89.50	89.50

In case designed turbine cycle heat rate and boiler efficiency are better than these values, the same shall be considered for calculation of design unit heat rate.

Provided further that in case the pressure and temperature parameters of a unit are different from the above ratings, the maximum design heat rate of the unit of the nearest class shall be taken:

Provided also that where the heat rate of the unit has not been guaranteed but turbine cycle heat rate and boiler efficiency are guaranteed separately by the same supplier or different suppliers, the design heat rate of the unit shall be arrived at by using guaranteed turbine cycle heat rate and boiler efficiency:

Provided also that where the boiler efficiency is lower than 86% for Sub- bituminous Indian coal and 89% for bituminous imported coal, the same shall be considered as 86% and 89% for Subbituminous Indian coal and bituminous imported coal, respectively, for computation of station heat rate:

Provided units based on a dry cooling system, the maximum turbine cycle heat rate shall be considered as per the actual design or 6% higher than the values given in the table above, whichever is lower;

Provided also that in the case of coal based generating station, if one or more generating units were declared under commercial operation prior to 01.04.2026, the heat rate norms for those generating units as well as generating units declared under commercial operation on or after 01.04.2026 shall be lowest of the heat rate norms considered by the Commission during control period or those arrived at by above methodology or the norms as per the sub-clause A1 of this Regulation:

Note: In respect of generating units where the boiler feed pumps are electrically operated, the maximum design heat rate of the unit shall be 40 kCal/kWh lower than the maximum design heat rate of the unit specified above with turbine driven Boiler Feed Pump

(iv) **Secondary Fuel Oil Consumption:**

(a) For Coal-based generating stations: 0.50 ml/kWh

(b) For Coal-based generating stations with wall (front/rear/sides) fired boilers: 1.00 ml/kWh

(v) **Auxiliary Energy Consumption**:

(a) For Coal-based generating stations:

	Generating Station	With Natural Draft cooling tower or without cooling tower
(i)	200 – 300 MW series	8.50%
(ii)	300 / 330 / 350 / 500 MW series and above	
	Steam driven boiler feed pumps	5.25%
	Electrically driven boiler feed pumps	8.00%
(iii)	600 MW and above	5.25%
	Steam driven boiler feed pumps	5.25%
	Electrically driven boiler feed pumps	8.00%

Provided that for thermal generating stations with induced draft cooling towers and where ball and tube-type coal mill is used, the norms shall be further increased by 0.50% and 0.80%, respectively:

Provided further that Additional Auxiliary Energy Consumption as follows shall be allowed for plants with Dry Cooling Systems:

Dry Cooling System	ross generation)
Direct cooling air cooled condensers with mechanical draft fans	1.0%
Indirect cooling system employing jet condensers with pressure recovery turbine and natural draft tower	0.5%

Note: The auxiliary energy consumption for the unit capacity of less than 200 MW sets shall be dealt with on a case-to-case basis.

B. **Norms for consumption of reagent:**

(1) The normative consumption of specific reagents for various technologies for the reduction of emission of sulphur dioxide shall be as under:

(a) For Wet Limestone based Flue Gas De-sulphurisation (FGD) system: The specific limestone consumption (g/kWh) shall be worked out by the following formula:

[K x Normative heat rate (kcal/kWh) x Sulphur content of coal (%)/GCV in kCal/Kg] x [85/LP]g/kWh

Where,

GCV = (a) Weighted Average Gross calorific value of coal in kCal per kg for coal based thermal generating stations computed in accordance with Regulation __ of these regulations;

LP = Limestone Purity in percentage

(b) For Lime Spray Dryer or Semi-dry Flue Gas Desulphurisation (FGD) system: The specific lime consumption shall be worked out based on minimum purity of lime (LP) as at 90% or more by applying formula [6 x 90/LP] g/kWh;

(c) For Dry Sorbent Injection System (using sodium bicarbonate): The specific consumption of sodium bicarbonate shall be 12 g per kWh at 100% purity.

(d) For Sea Water based Flue Gas Desulphurisation (FGD) system: The reagent used in sea water-based Flue Gas Desulphurisation (FGD) system shall be NIL.

(2) The normative consumption of specific reagent for various technologies for the reduction of emission of oxide of nitrogen shall be as below:

(a) For Selective Non-Catalytic Reduction (SNCR) System: The specific urea consumption of the SNCR system shall be 1.2 g per kWh at 100% purity of urea.

(b) For Selective Catalytic Reduction (SCR) System: The specific ammonia consumption of the SCR system shall be 0.6 g per kWh at 100% purity of ammonia.

C. **Norms for Hydro Generating Station and Pumped Storage Plants:**

C1. **Norms of Auxiliary Energy Consumption and Plant Availability Factor:**

Sl. No.	Type of Hydro Generating Station	Auxiliary Energy Consumption	PAF
i)	Purely run of the river	1.0%	90 %
ii)	Pondage/storage type run of the river	1.0%	85 %
iii)	Small Hydro Generating Station	1.0%	90 %
iv)	Pumped Storage Type	1.7%	95 %

Note:

(i) Small hydro generating stations mean all existing and future hydro generating stations having capacities of not more than 25 MW and consisting of such units whose turbo generator is under the same turbine floor and under the purview of the Commission, but are not specifically covered by the above table.

(ii) For WBSEDCL, Rammam HEP Stage-II is to be considered as purely run of the river scheme.

(iii) The normative availability factor of pumped storage type of hydro generating station shall be considered over a period of a year after deducting a downtime of 60 days or actual downtime whichever is less for each unit in the year once out of each five-year blocks for major overhauling. This shall be considered for the year in which such overhauling will be done.

C2. **Norms of Pumping Energy for Pumped Storage Hydro Generating Stations:**

The norms of pumping energy is as per cycling efficiency in % defined as ratio of generation energy to pumping energy where such generation is made due to such quantum of water that has been pumped by the said pumping energy. The norms for such cycle efficiency will be treated as 75%.

SCHEDULE – 6

OPERATION AND MAINTENANCE NORMS

A. **Thermal Generating Station:** Normative Operation and Maintenance expenses of thermal generating stations shall be as follows:

(1) Coal based generating stations, other than the generating stations or units referred to in clause (2) and (3) of this Schedule:

Figures in Rs. Lakh per MW

Year	200 /210/ 250 MW series	300/330/350 MW Series	500 MW Series	600/ 660 MW Series
2026 – 27	41.04	34.53	28.03	26.63
2027 – 28	42.16	35.48	28.80	27.36
2028 – 29	43.32	36.45	29.59	28.11
2029 – 30	44.51	37.45	30.40	28.88
2030 – 31	45.73	38.48	31.23	29.67

Provided that where there is more than two units in any generating station sharing common facilities / infrastructure, the overall O&M expenses shall be 0.90 times of the admissible O&M cost.

(1) Generating Stations of Kolaghat Thermal Power Station, Bandel Thermal Power Station Stage I of WBPDCL and Southern Thermal Power Station of CESC:

Figures in Rs. Lakh per MW

Year	Kolaghat TPS (4x210 MW)	Bandel TPS Stage I (1x60 MW)	Southern TPS (2x67.5 MW)
2026 – 27	50.35	61.10	61.10
2027 – 28	51.73	62.77	62.77
2028 – 29	53.15	64.49	64.49
2029 – 30	54.61	66.26	66.26
2030 – 31	56.11	68.08	68.08

(2) 12 MW Dishergarh Thermal Power Station of IPCL and 2 x150 MW units of Hiranmaye Energy Limited:

Figures in Rs. Lakh per MW

Year	Hiranmaye Energy Limited (2 x 150 MW)	Dishergarh TPS (1x12 MW)
2026 – 27	41.04	54.91
2027 – 28	42.16	56.41
2028 – 29	43.32	57.96

2029 – 30	44.51	59.55
2030 – 31	45.73	61.18

(3) The operation and maintenance expenses on account of emission control systems in coal or lignite based thermal generating stations shall be 2% of the admitted capital expenditure (excluding IDC and IEDC) as on its date of operation, which shall be escalated annually by applying Hybrid Inflation index considering 60% wholesale price index (WPI) and 40% consumer price index (CPI) of industrial workers, notified by the Government of India:

Provided that income generated from the sale of gypsum or other by-products shall be reduced from the operation and maintenance expenses.

B. **Hydro Generating Station:**

(1) The following operations and maintenance expense norms shall be applicable for hydro generating stations:

Figures in Rs. Lakh per MW

Year	Jaldhaka	Rammam	Purulia PSP	Small Hydro
2026 – 27	42.06	40.08	7.20	50.59
2027 – 28	43.21	41.18	7.40	51.98
2028 – 29	44.39	42.31	7.60	53.40
2029 – 30	45.61	43.47	7.81	54.86
2030 – 31	46.86	44.66	8.02	56.36

C. **Transmission System:**

(1) The following normative operation and maintenance expenses shall be admissible for the transmission system of WBSETCL:

Figures in Rs. Lakh per MW

PARTICULARS	2026 – 27	2027 - 28	2028 - 29	2029 - 30	2030 - 31
Norms for sub-station bays (Rs Lakh per bay)					
400 kV	7.11	7.30	7.50	7.71	7.92
220 kV	5.01	5.15	5.29	5.43	5.58
132 kV and below	3.55	3.65	3.75	3.85	3.96
Norms for Transformers (Rs. Lakh per MVA)					
O&M expenditure per MVA or per MVAr (Rs Lakh per MVA or per MVAr)	0.49	0.50	0.51	0.52	0.53

Norms for Transmission lines (Rs. lakh per km)					
400 kV Single circuit (twin & triple conductor)	0.45	0.46	0.47	0.48	0.49
400 kV Double circuit (twin & triple conductor)	0.80	0.82	0.84	0.86	0.88
400 kV Double circuit (bundled conductor)	1.19	1.22	1.25	1.28	1.32
400 kV Multi circuit (twin & triple conductor)	1.41	1.45	1.49	1.53	1.57
220 kV Single circuit (single conductor)	0.24	0.25	0.26	0.27	0.28
220 kV Double circuit (single conductor)	0.35	0.36	0.37	0.38	0.39
220 kV Multi circuit (single conductor)	1.41	1.45	1.49	1.53	1.57
132 kV Single circuit (single conductor)	0.24	0.25	0.26	0.27	0.28
132 kV Double circuit (single conductor)	0.35	0.36	0.37	0.38	0.39
132 kV Multi circuit (single conductor)	1.41	1.45	1.49	1.53	1.57

(2) For dedicated transmission line:

Composite O&M expenses for dedicated transmission line and bays of dedicated transmission line of any generating station for any ensuing years shall be determined based on the trued-up expenses of the last five years. O&M expenses for base year shall be computed considering the average of last 5 years', preceding to base year, trued up figures duly normalized after applying hybrid inflation index considering 60% wholesale price index (WPI) and 40% consumer price index (CPI) notified by the Government of India. O&M expenditure for the ensuing year shall be determined by applying average hybrid inflation index of last 5 years over the derived base value.

D. **Distribution Licensee:**

The following normative operation and maintenance expenses shall be admissible for the distribution licensees in the State, to the extent operating under the jurisdiction of the Commission:

In percentage of Gross Fixed Asset					
Distribution licensee	**2026 – 27**	**2027 - 28**	**2028 - 29**	**2029 - 30**	**2030 - 31**
WBSEDCL	11.53%	11.85%	12.17%	12.50%	12.84%
CESC	12.73%	13.08%	13.44%	13.81%	14.19%
IPCL	16.26%	16.71%	17.17%	17.64%	18.12%
DVC #	O&M of DVC are covered under composite tariff determined by CERC				

The normative O&M expenses includes expenses towards repair & maintenance, all consumables & spares, manpower cost, administrative & general expenses and all other costs incidental to the distribution network function and retail supply function. Distribution licensees having own generation station(s) are liable to claim O&M expenses for generating stations as per paragraph A of this Schedule.

Schedule - 7

Procedure for calculation of Transmission System Availability

1. Transmission system availability for a calendar month shall be computed by the respective Transmission Licensee, and certified by the SLDC, separately for each AC and HVDC transmission system. For the purpose of calculation of Transmission System Availability:

(i) AC transmission lines: Each circuit of AC transmission line shall be considered as one element.

(ii) Inter-Connecting Transformers (ICTs): Each ICT bank (three single phase transformer together) shall form one element.

(iii) Static VAR Compensator (SVC): SVC along with SVC transformer shall form one element. However, 50% credit to inductive and 50% to capacitive rating shall be given.

(iv) Bus Reactors/Switchable line reactors: Each Bus Reactors/Switchable line reactors shall be considered as one element.

(v) HVDC Bi-pole links: Each pole of HVDC link along with associated equipment at both ends shall be considered as one element.

(vi) HVDC back-to-back Station: Each block of HVDC back-to-back Station shall be considered as one element. If associated AC line (necessary for transfer of inter-regional power through HVDC back-to-back Station) is not available, the HVDC back-to-back Station block shall also be considered as unavailable.

2. The Availability of AC and HVDC portion of Transmission system shall be computed as under:

% Availability for AC system

$$= \frac{\text{oXAVo+pXAVp+qXAVq+rXAVr}}{\text{o+p+q+r}} \times 100$$

% Availability for HVDC system

$$= \frac{{}_{s}XAV_{s}+{}_{t}XAV_{t}}{s+t} \times 100$$

AV_o = Availability of o number of AC lines.

p = Total number of bus reactors/switchable line reactors

AV_p = Availability of p number of bus reactors/switchable line reactors.

q = Total number of ICTs.

AV_q = Availability of q number of ICTs.

r = Total number of SVCs.

AV_r = Availability of r number of SVCs.

s = Total number of HVDC poles.

AV_s = Availability of s number of HVDC poles.

t = Total number of HVDC back-to-back Station blocks.

AV_t = Availability of t number of HVDC back-to-back Station blocks

3. The weightage factor for each category of transmission element shall be as under:

   (a) For each circuit of AC line - Surge Impedance Loading (SIL) for Uncompensated line multiplied by ckt-km.

   SIL rating for various voltage levels and conductor configurations is given in Appendix I. However, for the voltage levels and/or conductor configurations not listed in Appendix I, appropriate SIL based on technical considerations may be used for availability calculation under intimation to long-term transmission customers/DICs.

   For compensated AC line, SIL shall be as certified by the SLDC Secretariat considering the compensation on the line.

   For shunt compensated line, the reduced value of SIL shall be taken in accordance with the location of the reactor. Similarly, in case of the lines with series compensation, the higher SIL shall be taken as per the percentage of compensation.

   (b) For each HVDC pole: The rated MW capacity x ckt-km.
   (c) For each ICT bank: The rated MVA capacity.
   (d) For SVC: The rated MVAR capacity (inductive and capacitive).
   (e) For Bus Reactor/switchable line reactors: The rated MVAR capacity.
   (f) For HVDC back-to-back Station connecting two regional grids: Rated MW capacity of each block.

4. The availability for each category of transmission element shall be computed based on the weightage factor, total hours under consideration and non-available hours for each element of that category. The formulae for calculation of Availability of each category of the transmission elements are as per Appendix-II.
5. The transmission elements under outage due to following reasons shall be

deemed to be available:

(i) Shut down availed for maintenance or construction of elements of another transmission scheme. If the other transmission scheme belongs to the Transmission Licensee, the SLDC may restrict the deemed availability period to that considered reasonable for the work involved.

(ii) Switching off of a transmission line to restrict over voltage and manual tripping of switched reactors as per the directions of SLDC.

6. Outage time of transmission elements for the following contingencies shall be excluded from the total time of the element under period of consideration:

(i) Outage of elements due to acts of God and force majeure events beyond the control of the Transmission Licensee. However, onus of satisfying the SLDC that element outage was due to aforesaid events and not due to design failure shall rest with the Transmission Licensee. A reasonable restoration time for the element shall be considered and any additional time taken by the Transmission Licensee for restoration of the element beyond the reasonable time shall be treated as outage time attributable to the Transmission Licensee. Circuits restored through ERS (Emergency Restoration System) shall be considered as available.

(ii) Outage caused by grid incident/disturbance not attributable to the Transmission Licensee, e.g., faults in substation or bays owned by other agency causing outage of the Transmission Licensee's elements, and tripping of lines, ICTs, HVDC, etc. due to grid disturbance. However, if the element is not restored on receipt of direction from RLDC while normalizing the system following grid incident/disturbance within reasonable time, the element will be considered not available for the period of outage after issuance of RLDC's direction for restoration.

Appendix-I

SURGE IMPEDANCE LOADING (SIL) OF AC LINES

Sl. No.	Line voltage (kV)	Conductor Configuration	SIL (MW)
1	765	Quad Bersimis	2250
2	400	Quad Bersimis	691
3	400	Twin Moose	515
4	400	Twin AAAC	425
5	400	Quad Zebra	647
6	400	Quad AAAC	646
7	400	Triple Snowbird	605
8	400	ACKC (500/26)	556
9	400	Twin ACAR	557
10	220	Twin Zebra	175
11	220	Single Zebra	132
12	132	Single Panther	50
13	66	Single Dog	10

Appendix-II

FORMULAE FOR CALCULATION OF AVAILABILITY OF EACH CATEGORY OF TRANSMISSION ELEMENTS

AV_o (Availability of o number of AC lines) $= \sum_{i=1}^{0} \frac{W_i(T_i - T_{NAi})}{T_i} \Big/ \sum_{i=1}^{0} W_i$

AV_s (Availability of s number of HVDC poles) $= \sum_{j=1}^{s} \frac{W_j(T_j - T_{NAj})}{T_j} \Big/ \sum_{j=1}^{s} W_j$

AV_q (Availability of q number of ICTs.) $= \sum_{k=1}^{q} \frac{W_k(T_k - T_{NAk})}{T_k} \Big/ \sum_{k=1}^{q} W_k$

AV_r (Availability of r no. of SVCs.)

$= \left[\sum_{l=1}^{r} 0.5 \frac{W_i l(T_i l - T_{NAi} l)}{T_i l} + \sum_{l=1}^{r} 0.5 \frac{W_c l(T_c l - \quad _{Ac} l)}{T_c l}\right] / \left[\sum_{l=1}^{r} 0.5 W_i l + \sum_{l=1}^{r} 0.5 W_c l\right]$

AV_p (Availability of p no of switched bus reactors) $= \sum_{m=1}^{p} \frac{W_m(T_m - T_{NAm})}{T_m} \Big/ \sum_{m=1}^{p} W_m$

AVt (Availability of t no. of HVDC back-to-back blocks) = $\sum_{n=1}^{t} \frac{W_n(T_n - T_{NAn})}{T_n} \,/\, \sum_{n=1}^{t} W_n$

Where,

W_i = Weightage factor for i^{th} tramission line

W_j = Weightage factor for j^{th} HVDC pole

W_k = Weightage factor for k^{th} ICT

$W_i l$ & $W_c l$ = Weightage factor for inductive & capacitive Operation of lth SVC

W_m = Weightage factor for m^{th} bus reactor

W_n = Weightage factor for n^{th} HVDC back-to-back block.

$T_i, T_j, T_k, T_i l, T_c l$, Tm&Tn = The total hours of i^{th} AC line j^{th} HVDC pole,k^{th} ICT l^{th} SVC (Inductive Operation), lth SVC (Capacitive Operation), mth Switched Bus Reactor & nth HVDC back-to-back block during the period under consideration (excluding time period for outages not attributable to Transmission Licensee for reasons given in Para 6 of the procedure)

$T_{NA}i, T_{NA}j, T_{NA}k, T_{NAC}l, T_{NA}m$ = The non-availability hours (excluding the time period for TNAIL, outages not attributable to transmission Licensee taken as TNAI, deemed availability as per Para 5 of the procedure) for ith AC line, jth HVDC pole, kth ICT, lth SVC (Inductive Operation), lth SVC (Capacitive Operation), mth Switched Bus Reactor and nth HVDC back-to-back block.

SCHEDULE-8

Computations of Reliability Indices

1. Adequate data shall be recorded to calculate the following reliability indices. The licensee shall calculate the values of these indices as per the formula and methodology specified below:

   a) System Average Interruption Frequency Index (SAIFI):

   It is the average number of interruptions (longer than 5 minutes) that a customer would experience and is calculated as:

$$SAIFI = \sum_{i=1}^{n} (Ai\ x\ Ni)/Nt$$

   b) System Average Interruption Duration Index (SAIDI):

   It is the average outage duration for each customer served and is calculated as:

$$SAIDI = \sum_{i=1}^{n} (Bi\ x\ Ni)/Nt$$

   c) Momentary Average Interruption Frequency Index (MAIFI):

   It is the average number of interruptions (less than 5 minutes) that a customer would experience and is calculated as:

$$MAIFI = \sum_{i=1}^{n} (Ci\ x\ Ni)/Nt$$

   Where,

Ai	= Total number of sustained interruption (each longer than 5 minutes) on i^{th} feeder for the month;
Bi	= Total duration of all sustained interruption on i^{th} feeder for the month
Ci	= Total number of momentary interruption (each less than or equal to 5 minutes) for i^{th} feeder for the month
Ni	= Number of consumers connected to i^{th} feeder affected due to each interruption
Nt	= Total number of consumers in the distribution licensee's supply area
n	Number of 11 kV feeders in the licensed area of supply (excluding those serving predominantly agriculture load)

2. Distribution licensee shall meter all 11 kV feeders with consumer mapping and online data transfer facility to compute the SAIFI, SAIDI, MAIFI through software. The licensee shall ensure proper software audit in the manner as may be directed by the Commission from time to time.

3. The data for reliability indices in clause (a), (b) and (c) of paragraph 1 shall be computed on monthly basis and uploaded in the website of licensee with the feeder-wise details. A soft copy of the same shall also

be submitted to the Commission on monthly basis. The annual indices shall be computed based on such monthly data for the purpose of computation of incentive under these Regulations.

SCHEDULE-9

Computations of Aggregate Technical and Commercial (AT&C) Losses

AT&C losses comprises of technical loss and commercial loss, and is expressed as the difference between energy input units into the system and the units for which the payment is collected.

$$AT\&C\ Loss\ (\%) = \frac{(Energy\ input - Energy\ realised)\ x\ 100}{Energy\ input}$$

Where,

Input Energy (MU) = (E_g−AC+E_P−E_t) – TL

Energy realized (MU) = Energy Billed x Collection efficiency

Energy billed (MU) = Esc – Et

Collection efficiency (%) = {(Adjusted Revenue realised x 100)/ Adjusted Revenue billed}

Adjusted Revenue Billed (Rs. Cr) = Rsc + Rsb - R_t

Adjusted Revenue Realised (Rs. Cr) = (Rsc + Rsr - Rt + Do - Dc)

Eg (MU)	= Energy generated (gross)
AC (MU)	= Auxiliary consumption
Ep (MU)	= Energy purchased (gross)
Et (MU)	= Energy traded / sale to person other than consumers
TL (MU)	= Transmission loss
Esc (MU)	= Energy sold to all category of consumers
Rsc (Rs. Cr)	= Revenue from sale of energy to consumers
Rsb (Rs. Cr)	= Subsidy booked
Rsr (Rs. Cr)	= Subsidy received
Rt (Rs. Cr)	= Revenue from energy traded / sale to person other than consumers
Do (Rs. Cr)	= Opening debtor for sale of energy as shown in Receivable Schedule (without deducting provisions of doubtful debtor). Unbilled revenue shall not be considered as debtors
Dc (rs. Cr)	= (i) Closing debtor for sale of energy as shown in Receivable Schedule (without deducting provisions of doubtful debts). Unbilled revenue shall not be considered as debtors.

+

(ii) any amount written off during the year directly from (i)

Note:

1. Open access / wheeling energy shall neither be included in Energy input nor in Energy sold;

2. No adjustment shall be made in revenue from sale of energy on account of unbilled revenue;

3. Total subsidy received during the year including arrears (if any) shall also be included while calculating Adjusted revenue from sale of energy on subsidy received basis

ANNEXURE – I

DEPRECIATION SCHEDULE FOR ASSETS COD PRIOR TO 01.04.2026

Sr. No.	Depreciation of Assets	Depreciation Rate (Straight line method) - for Assets or Schemes prior 01.04.2026
A	**LAND UNDER FULL OWNERSHIP**	0.00%
B	**LAND UNDER LEASE**	
(a)	for investment in the land	3.34%
(b)	For the cost of clearing the site	3.34%
(c)	Land for reservoir in case of hydro generating station	3.34%
C	**PLANT AND MACHINERY**	
(a)	**Plant & Machinery in generating stations**	
(i)	Hydro electric	5.28%
(ii)	Steam electric	5.28%
(iii)	NHRB & waste heat recovery boilers	5.28%
(iv)	Diesel electric and gas plant	5.28%
(b)	**Cooling towers & circulating water systems**	5.28%
(c)	**Hydraulic works forming part of the Hydro-generating stations**	
(i)	Dams, Spillways, Weirs, Canals, Reinforced concrete flumes and siphons	5.28%
(ii)	Reinforced concrete pipelines and surge tanks, steel pipelines, sluice gates, steel surge tanks, hydraulic control valves and hydraulic works	5.28%
d.	**Building & Civil Engineering works**	
(i)	Offices and showrooms	3.34%
(ii)	Containing thermo-electric generating plant	3.34%
(iii)	Containing hydro-electric generating plant	3.34%
(iv)	Temporary erections, such as wooden structures	18.00%
(v)	Roads other than Kutcha roads	3.34%
(vi)	Others	3.34%
e.	**Transformers, Kiosks, sub-station equipment & other fixed apparatus (including plant)**	
(i)	Transformers, including foundations having a rating of 100 KVA and over	5.28%
(ii)	Others	5.28%
f.	**Switchgear, including cable connections**	5.28%
g.	**Lightning arrestor**	
(i)	Station type	5.28%
(ii)	Pole type	5.28%
(iii)	Synchronous condenser	5.28%
h.	**Batteries**	18.00%
(i)	Underground cable, including joint boxes and disconnected boxes	5.28%
(ii)	Cable duct system	5.28%
i.	**Overhead lines, including cable support**	
(i)	Lines on fabricated steel operating at terminal voltages higher than 66 KV	5.28%
(ii)	Lines on steel supports operating at terminal voltages higher than 13.2 KV but not exceeding 66 KV	5.28%

Sr. No.	**Depreciation of Assets**	**Depreciation Rate (Straight line method) - for Assets or Schemes prior 01.04.2026**
(iii)	Lines on steel on reinforced concrete support	5.28%
(iv)	Lines on treated wood support	5.28%
j.	**Meters**	5.28%
k.	**Self-propelled vehicles**	18.00%
l.	**Air Conditioning Plants**	
(i)	Static	5.28%
(ii)	Portable	18.00%
m		
(i)	Office furniture and furnishing	6.33%
(ii)	Office equipment	6.33%
(iii)	Internal wiring, including fittings and apparatus	6.33%
(iv)	Street Light fittings	5.28%
n.	**Apparatus let on hire**	
(i)	Other than motors	18.00%
(ii)	Motors	6.33%
o.	**Communication equipment**	
(i)	Radio and high frequency carrier system	15.00%
(ii)	Telephone lines and telephones	15.00%
(iii)	Fibre Optic/OPGW	6.33%
p.	**I. T Equipment**	15.00%
q.	**Software, SCADA system**	15.00%
r.	**Any other assets not covered above**	5.28%

ANNEXURE – II

DEPRECIATION SCHEDULE FOR ASSETS COD ON & AFTER 01.04.2026

Sr. No.	Depreciation of Assets	Depreciation Rate (Straight line method) - for New Assets or Schemes
A	**LAND UNDER FULL OWNERSHIP**	0.00%
B	**LAND UNDER LEASE**	
(a)	for investment in the land	3.34%
(b)	For the cost of clearing the site	3.34%
(c)	Land for reservoir in case of hydro generating station	3.34%
C	**PLANT AND MACHINERY**	
(a)	**Plant & Machinery in generating stations**	
(i)	Hydro electric	4.22%
(ii)	Steam electric	4.22%
(iii)	NHRB & waste heat recovery boilers	4.22%
(iv)	Diesel electric and gas plant	4.22%
(b)	**Cooling towers & circulating water systems**	4.22%
(c)	**Hydraulic works forming part of the Hydro-generating stations**	
(i)	Dams, Spillways, Weirs, Canals, Reinforced concrete flumes and siphons	4.22%
(ii)	Reinforced concrete pipelines and surge tanks, steel pipelines, sluice gates, steel surge tanks, hydraulic control valves and hydraulic works	4.22%
d.	**Building & Civil Engineering works**	
(i)	Offices and showrooms	3.34%
(ii)	Containing thermo-electric generating plant	3.34%
(iii)	Containing hydro-electric generating plant	3.34%
(iv)	Temporary erections, such as wooden structures	18.00%
(v)	Roads other than Kutcha roads	3.34%
(vi)	Others	3.34%
e.	**Transformers, Kiosks, sub-station equipment & other fixed apparatus (including plant)**	
(i)	Transformers, including foundations having a rating of 100 KVA and over	4.22%
(ii)	Others	4.22%
f.	**Switchgear, including cable connections**	4.22%
g.	**Lightning arrestor**	
(i)	Station type	4.22%
(ii)	Pole type	4.22%
(iii)	Synchronous condenser	4.22%
h.	**Batteries**	18.00%
(i)	Underground cable, including joint boxes and disconnected boxes	4.22%
(ii)	Cable duct system	4.22%
i.	**Overhead lines, including cable support**	
(i)	Lines on fabricated steel operating at terminal voltages higher than 66 KV	4.22%
(ii)	Lines on steel supports operating at terminal voltages	4.22%

Sr. No.	Depreciation of Assets	Depreciation Rate (Straight line method) - for New Assets or Schemes
	higher than 13.2 KV but not exceeding 66 KV	
(iii)	Lines on steel on reinforced concrete support	4.22%
(iv)	Lines on treated wood support	4.22%
j.	**Meters**	4.22%
k.	**Self-propelled vehicles**	18.00%
l.	**Air Conditioning Plants**	
(i)	Static	4.22%
(ii)	Portable	18.00%
m		
(i)	Office furniture and furnishing	6.33%
(ii)	Office equipment	6.33%
(iii)	Internal wiring, including fittings and apparatus	6.33%
(iv)	Street Light fittings	4.22%
n.	**Apparatus let on hire**	
(i)	Other than motors	18.00%
(ii)	Motors	6.33%
o.	**Communication equipment**	
(i)	Radio and high frequency carrier system	15.00%
(ii)	Telephone lines and telephones	15.00%
(iii)	Fibre Optic/OPGW	6.33%
p.	**I. T Equipment**	15.00%
q.	**Software, SCADA system**	15.00%
r.	**Any other assets not covered above**	4.22%

ANNEXURE – III

DEPRECIATION SCHEDULE FOR INTEGRATED MINE

Sr. No.	Asset Particulars	Life in Years
1	Land Freehold@	999
2	Land Leasehold	&&&
3	Temporary erections	1
4	HEMM$	8
5	Roads, bridges, culverts, helipads	25
6	Main Plant Buildings	30
7	Machinery other than HEMM	15
8	Water Supply, Drainage, and sewerage	15
9	Furniture and Fixtures	15
10	Office equipment/s other than computers	15
11	Hospital equipment(s)	15
12	EDP, WP machines, SATCOM & communication equipment	15
13	Electrical installations	15
14	Self-propelled vehicles	10
15	Computers, Software	6.33
16	Mine Development Expenses and Evaluation and Exploration#	20 or life of mine, whichever is lower
17	Evaluation and Exploration#	
18	Others not covered above	15
*	Salvage Value shall be other than 5% for the following assets – a. IT Equipment, software Zero (0) b. Zero or as agreed with the state Government in case of land c. For specialized mining equipment as specified by the Ministry of Corporate affairs Mine Development expenses, Evaluation and Exploration Zero (0)	
@	Petitioner to submit if the Freehold Land is attached with any conditions for return. If yes submit the conditions and period after which the land is to be returned. In such a case, the land shall be depreciable based on such details.	
&&&	To be filled by petitioner, least of lease agreement/mine life/right to use period	
$	List of individual HEMM with the cost of each HEMM be provided separately	
#	In a generic sense Mine Development Expenditure is the expenditure incurred to bring the mine into usable condition after ensuring the economic viability and decision is taken by the Mine Owner to develop the mine. While filling under this head, details to the extent feasible are to be given separately. Evaluation and exploration expenditure is generally the expenditure incurred associated with finding the mineral by carrying out topographical, geological, geochemical, and geophysical studies, exploratory drilling, trenching, sampling, expenditure for activities in relation to evaluation of technical feasibility and commercial viability, acquisition of rights to explore etc. While filling under this head, details to the extent feasible are to be given separately.	

ANNEXURE -IV

DIFFERENT CLASSES OF CONSUMERS

Sl No	Consumer Category	Voltage Level	Specific Provisions
1	Domestic – life line	LV	This life-line tariff category is applicable to Residential consumers who have a Sanctioned Load upto 0.3 kW and having monthly consumption of 25 units in case of monthly billing or having quarterly consumption of 75 units in case of quarterly billing, and who have consumed upto 300 units per annum in the previous financial year. The eligibility of such consumers will be reassessed at the end of each financial year. If more than 360 units have been consumed in the previous financial year, the LT Domestic tariff shall thereafter be applicable. This Domestic – life line tariff shall be applicable only to individuals and not to institutions.
2	Domestic	LV / MV / HV	This tariff category is applicable for electricity used for operating various appliances used for purposes such as lighting, heating, cooling, cooking, washing/cleaning, entertainment/leisure, water pumping and EV charging in the following premises: a) Private residential premises, Government/semi-Government residential quarters; home-stay, Private corporate bodies staff quarters, Tea garden labour quarters; b) Guest Houses/ Holiday Homes /Student Hostels situated outside the premises of educational institutions run by the Government / local bodies or charitable organizations/ trusts; c) Other types of Homes/Hostels, such as (i) Old age homes, (ii) Homes/Hostels for Destitute, Disabled Persons (physically or mentally handicapped persons, etc.) and mentally ill persons (iii) Remand Homes (iv) Rescue Homes, (v) Dharmshalas, (vi) Orphanages - subject to verification and confirmation by the Distribution Licensee's concerned. d) Premises /places used for worship, such as temples, gurudwaras, churches, mosques, etc.; e) Common facilities such as Water Pumping / Street and other common area Lighting / Lifts /Parking Lots/ Fire-fighting Pumps and other equipment, etc. in the Government / Private / Co-operative Housing Societies / Colonies/complexes (where electricity is used exclusively for domestic purposes);

<table>
<tr><th>Sl No</th><th>Consumer Category</th><th>Voltage Level</th><th>Specific Provisions</th></tr>
<tr><td></td><td></td><td></td><td>f) Sports Clubs or facilities / Health Clubs or facilities / Gymnasium / Swimming Pool / Community Hall of Government / Private / Co-operative Housing Colonies/ complexes - provided that they are situated in the same premises, and are for the exclusive use of the members and employees of such Housing Colonies/complexes;

g) Entities supplied electricity at a single point for residential purposes, in accordance with the Electricity (Removal of Difficulties) Eighth Order, 2005, in the following cases:

(i) a Co-operative Group Housing Society which owns the premises, for making electricity available to the members of such Society residing in the same premises for residential purposes; and
(ii) a person, for making electricity available to its employees residing in the same premises for residential purposes.

2. Tariff may be differentiated based on supply voltage, area of supply (rural, urban, etc.) and Time of the Day (ToD):

Provided that different energy charge shall be specified for different consumption slab in LV supply as below:

<table>
<tr><th>Monthly consumption basis</th><th>Quarterly consumption basis</th></tr>
<tr><td>First 34 unit</td><td>First 102 unit</td></tr>
<tr><td>Next 26 unit</td><td>Next 78 unit</td></tr>
<tr><td>Next 40 unit</td><td>Next 120 unit</td></tr>
<tr><td>Next 100 unit</td><td>Next 300 unit</td></tr>
<tr><td>Next 100 unit</td><td>Next 300 unit</td></tr>
<tr><td>Above 300 unit</td><td>Above 900 unit</td></tr>
</table>
</td></tr>
<tr><td>3</td><td>Commercial</td><td>LV / MV / HV / EHV</td><td>1. This tariff category is applicable for electricity used in non-residential, non-industrial and/or commercial premises for commercial consumption meant for operating various appliances used for purposes such as lighting, heating, cooling, cooking, entertainment/ leisure, water pumping and EV charging, but not limited to, the following premises:

a) Non-Residential, Commercial and Business premises, including shopping malls and Showrooms, Exhibition Centers, mela /fair;

b) Warehouses / Godowns;</td></tr>
</table>

Sl No	Consumer Category	Voltage Level	Specific Provisions
			c) Combined lighting and power supply for facilities relating to Entertainment, including film studios, cinemas and theatres (including multiplexes), Hotels, Restaurants, Private guest Houses / Holiday Homes, Leisure, Meeting/Town Halls, and places of Recreation and Public Entertainment; Offices, including Commercial Establishments; Marriage Halls, Canteens / Cafeterias, Ice-cream parlors, Coffee / Tea Shops, Internet / Cyber Cafes, Telephone Booths, and Fax / Photocopy shops; d) Automobile and all other types of repairs, servicing and maintenance centres, Retail Gas Filling, Petrol Pumps and Service Stations, including Garages; e) Toll Collection plazas; f) Computer Training Institutes, Private Training centres, Typing Institutes, Photo Laboratories, Private Diagnostic Centres, Consultation chambers of Physician, Engineers, Charter Accountants and lawyers; g) Banks and ATM centres, Telephone Exchanges, TV Stations, Radio Stations, IT data centers; h) LPG/CNG bottling plants and associated retail gas filling stations, Bulk Fuel Blending Units; i) Telecommunications Towers and associated telecom infrastructure including related offices/outlets etc.; j) Common facilities, like Water Pumping / Lifts / Fire-Fighting Pumps and other equipment / Street and other common area lighting, etc., in Commercial Complexes; k) Sports Clubs/facilities, Health Clubs/facilities, Gymnasiums, Swimming Pools not covered under any other category; l) External illumination of monuments/ historical/ heritage buildings approved by the concerned Local Authority; m) Construction of all types of structures/ infrastructures such as buildings, bridges, fly-overs, dams, Power Stations, roads, Aerodromes, tunnels, for laying of pipelines for all purposes; n) Sewage Treatment Plants/ Common Effluent Treatment Plants for Commercial Complexes. o) Advertisements, hoardings (including hoardings fixed on lamp posts/installed along roadsides), and other commercial illumination such as external flood-lights, displays, neon signs at departmental stores, malls, multiplexes, theatres, clubs and other such establishments.

<table>
<tr><th>Sl No</th><th>Consumer Category</th><th>Voltage Level</th><th>Specific Provisions</th></tr>
<tr><td></td><td></td><td></td><td>2. Tariff may be differentiated based on supply voltage, contracted demand, purpose of supply, area of supply (rural, urban, etc.), Time of Day (ToD), Load factor and Power Factor:

Provided that different energy charge shall be specified for different consumption slab in LV supply as below:

<table><tr><td>Monthly consumption basis</td><td>Quarterly consumption basis</td></tr><tr><td>First 60 unit</td><td>First 180 unit</td></tr><tr><td>Next 40 unit</td><td>Next 120 unit</td></tr><tr><td>Next 50 unit</td><td>Next 150 unit</td></tr><tr><td>Next 150 unit</td><td>Next 450 unit</td></tr><tr><td>Above 300 unit</td><td>Above 900 unit</td></tr></table></td></tr>
<tr><td>4</td><td>Agriculture and allied activities</td><td>LV / MV / HV</td><td>1. This tariff category is applicable for electricity / power supply for agriculture and allied activities as below:

a) Raising of crops including food and non-food crops, fodder grass, fruits and vegetables, flowers, any other horticulture crops and plantation;

b) Animal husbandry and dairy; livestock and livestock products, poultry farming, stock breeding; fishery; sericulture, mushroom farming, indoor vertical farming, etc.;

c) Power supply for fodder/ crop cutters for self-use and for agriculture processing operations.

However, this excludes operating a flour mill, oil mill or expeller in the same premises, either operated by a separate motor or a change of belt drive, which are to be supplied at industrial tariff.

2. Tariff may be differentiated based on supply voltage, contracted demand, purpose of supply, area of supply and Time of Day (ToD).</td></tr>
<tr><td>5</td><td>Commercial Plantation</td><td>LV / MV / HV / EHV</td><td>1. This tariff category is applicable for electricity for watering or dewatering for commercial plantation purpose like tea garden, etc.

2. Tariff may be differentiated based on supply voltage, contracted demand and Time of Day (ToD).</td></tr>
<tr><td>6</td><td>Industrial</td><td>LV / MV/ HV / EHV</td><td>1. This tariff category is applicable for electricity for Industrial use, for the purpose of supplying to:</td></tr>
</table>

Sl No	Consumer Category	Voltage Level	Specific Provisions
			(a) manufacturing and processing units, including electricity used within such premises for motive power, general lighting, heating/cooling, Research & Development, manufacturing, Processing, Melting, Blending, Mixing, Refining, Printing, Product Testing, Packing, EV charging, etc. It also includes supply for Administrative office, Research & Development unit, canteens, sport club or other facilities, street lights, fire-fighting equipments, etc. situated in the same industrial premises and supplied power from same point of supply. (b) It shall also be applicable for (but not limited to) the following purposes (i) Oil Mill, Flour Mill, Dal Mill, Rice Mill, Poha Mill, Masala Mill, Saw Mill, Cattle / Poultry Feed Manufacturing plants; (ii) Ice Factory, Ice-cream manufacturing units, Milk Processing or Chilling Plants (Dairy); (iii) Cold Storages, Packaged Drinking water plant; (iv) Engineering Workshops, Printing Presses; Packaging material manufacturing; (v) Defence workshops / Ordinance factories; (vi) Manufacturing units / Workshops of Railways, Metro-rail; (vii) Mining, Quarrying, Stone Crushing units; Brick Kiln (Bhatti), Biomass Pellet; (viii) Food (including seafood and meat) Processing units; (ix) Cottage industry, artisan, weaver and small production-oriented establishment (x) Power looms including other allied activities like, Warping, Doubling, Twisting, etc., connected; (xi) Biotechnology Industries; (xii) Common Service for Industrial Estates; 2. Tariff may be differentiated based on supply voltage, contracted demand, purpose of supply, area of supply (rural, urban, etc.), Time of Day (ToD), Load factor and Power factor.
7	Street Light	LV / MV	1. This tariff category is applicable for the electricity used for lighting of

Sl No	Consumer Category	Voltage Level	Specific Provisions
		/HV	public streets/ thoroughfares which are open for use by the general public, traffic signaling system; Provided that Street-lights in residential complexes, commercial complexes, industrial premises, etc. will be billed at the tariff of the respective applicable categories. 2. Tariff may be differentiated based on supply voltage and area of supply (rural, urban, etc).
8	Public Water Works / Sewerage treatment plant	LV / MV / HV / EHV	1. This tariff category is applicable for electricity / power supply for pumping of water, purification of water and allied activities relating to Public Water Supply Schemes, Sewage Treatment Plants and Waste Processing Units, provided they are either owned/or operated/or managed or operated by designated operator appointed by Local Self-Government Bodies (Gram Panchayats, Panchayat Samitis, Zilla Parishads, Municipal Councils and Corporations, etc.), All other Water Supply Schemes and Sewage Treatment Plants (including allied activities) shall be billed under the respective tariff category, as the case may be. 2. Tariff may be differentiated based on supply voltage, contracted demand, area of supply (rural, urban, etc.), Load Factor and Power Factor.
9	Public Services	LV/ MV/ HV/ EHV	1. This tariff is applicable for electricity supply for the followings: a) All offices of Government and Municipal/ Local Authorities/ Local Self-Government bodies, such as Municipalities, Zilla Parishads, Panchayat Samitis, Gram Panchayats; Police Stations and Police Chowkies, Post Offices; fire Service Stations; correctional home, Courts, crematorium / burial grounds; b) State or Municipal/Local Authority Transport establishments; Office and establishments of Railways and Port authority. c) Armed Force / Defence / Paramilitary establishments; d) Educational Institutions, such as Schools, Colleges, Universities; Libraries and public reading rooms; Health Care facilities, such as Hospitals, Dispensaries, Clinics, Primary Health Care Centres, Diagnostic Centres, Blood Bank and Pathology Laboratories; e) Hostels/ Sports Clubs and facilities / Health Clubs and facilities / Gymnasium / Swimming Pools attached to such Educational

Sl No	Consumer Category	Voltage Level	Specific Provisions
			Institutions / Hospitals/ Health Care facilities, provided that they are situated in the same premises and are meant primarily for their students / faculty/ employees/ patients; f) Historical monuments, public parks, children parks, playground, etc. g) Service oriented spiritual / charitable organizations / trusts; 2. Tariff may be differentiated based on supply voltage, contracted demand purpose of supply and area of supply (rural /urban): Regarding purpose of supply, (i) the institutions / facilities run or aided by Government/ local bodies/ constituted under act of Parliament / non-profit making organizations and (ii) the institutes / facilities run on commercial principles may be considered separately.
10	Transportation	HV / EHV	1. This tariff category is applicable to traction and offshore power supply for Railways, Tramways, Metrorail, Airports, Ports, Jetties including Stations and Shops, Workshops, Yards, office, etc. within the same premises: Provided that for the establishments, workshops and manufacturing units situated in a separate premise, relevant tariff category shall be applicable. 2. Tariff may be differentiated based on supply voltage, purpose of supply, contracted demand and area of supply (rural, urban, etc.):
11	EV Charging Station	LV/ MV / HV / EHV	This Tariff category is applicable for Electric Vehicle Charging Station including battery swapping station for electric vehicle including other facilities such as restaurants, rest rooms, convenience stores, etc. situated in the same premises. In case the consumer uses the electricity supply for charging his own electric vehicle at their premises, the tariff applicable shall be as per the category of such premises.

Note:

(1) All Distribution Licensee shall submit its tariff proposal for all the categories mentioned above considering the specific provisions for the consumer category.

(2) Where there is no existing consumer of any of the above category, the licensee shall submit a proposed tariff based on its best estimation. In case licensee do not propose tariff of any specific consumer category mentioned above, shall provide detailed justification in its petition. If the Commission is not satisfied with the submission of the licensee, the Commission can suo-motu fix the tariff of that

consumer category based on its own analysis.

(3) Any institute or organization claiming as Charitable organization / trust referred in this schedule should be a registered non-profitable organization for the respective purpose under the Societies Registration Act 1860, as amended from time to time. They shall submit such documents to the satisfactory of the distribution licensee.

(4) Emergency / Short-term / Temporary supply to consumer shall pay 1.5 time applicable fixed/demand charges and 1.25-time applicable energy charge of the respective category: Provided that for short-term supply the fixed / demand charge shall be levied on prorate basis for number of days.

For this purpose, Short-term / Temporary supply includes events, mela / fair, festivals, marriage ceremony and supply for construction purpose. Such short-term supply shall not have any load factor rebate and power factor rebate. However, other charges for such short-term supply shall be the same as are applicable to that particular category of consumer to which the applicant seeking such short-term supply belongs. For such short-term supply, consumer shall apply to the licensee at least 10 days in advance for LV and MV consumers and at least 20 days in advance for HV consumer.

(5) Start-up / survival power for Generating Plants of a Generating Company or IPP, i.e. the power required for trial run of a Power Plant during commissioning of the Unit and its Auxiliaries, and for its start-up after planned or forced outage (but not for construction) shall pay 1.5 times applicable demand charge and 1.25 times applicable energy charge at industrial tariff. Such supply shall not have any load factor rebate and power factor rebate.

(6) For consumers having in-situ captive plan, meeting part of its consumption from the distribution licensee and has a contract demand with the licensee, tariff for respective consumer category will be applicable.

However, where the user of in-situ captive plant /Captive Plant do not have any contract demand in consumer mode but synchronized its captive plant with distribution system, draw power during planned or forced outage or maintenance of captive power plant, any flow of power for consumption by the consumer/ captive plant shall be considered as Emergency /Short-term / Temporary supply.

In case of outage / maintenance of its in-situ captive plant/ Captive Plant, power may take with two (02) days advance intimation to licensee.

ANNEXURE V

TEMPLATE OF PUBLIC NOTICE

……………………………………….. (NAME OF APPLICANT)
…………………………………… (REGISTERED OFFICE ADDRESS)

PUBLIC NOTICE

GIST OF THE APPLICATION
SUBMITTED BEFORE THE WEST BENGAL ELECTRICITY REGULATORY COMMISSION

1. …………………………………………**<Name of applicant>** has made an application before the West Bengal Electricity Regulatory Commission (Commission) for determination of Tariff, Aggregate Revenue Requirement and Expected Revenue from Charges of all the ensuing years of the ___ control period consisting …….. <year> to …. <year> **/** True Up for the year ….. **/** In-principle approval **<as may be applicable>** for its _____ **<specify type of business>**.

   The application has been admitted by the Commission on ……………………………………………(date) and registered in Case No……….

2. The gist of the application for < determination of Tariff / True Up / In-principle approval (as applicable)> is as follows:

   (I) For Determination of Tariff, Aggregate Revenue Requirement and Expected Revenue from Charges:

   (i) Details of Proposed Tariff and effective from the billing month of April of every ensuing year: (Only applicable portion to be filled up)

   (A) For Generating Company:

   (Separate figures to be given for each generating station)

Name of the Generating Station / Unit	Tariff for the Base year	Tariff for the control period …… (year) to …… (year)				
		1st year	2nd year	3rd year	4th year	5th year
Capacity Charge in Rs. Lakh						
Energy Charge in Rs. / kWh						

(B) For Transmission Licensee:

Name of the Transmission Licensee	Tariff for the Base year	Tariff for the control period .... (year) to ...... (year)				
		1st year	2nd year	3rd year	4th year	5th year
Rate for Long Terms (Rs/MW/month)						
Rate for Short Term Customer (Rs/kWh)						

(C) For Distribution Licensee:

Name of the Distribution Licensee	Tariff for the Base year	Tariff for the control period .... (year) to ...... (year)				
		1st year	2nd year	3rd year	4th year	5th year
Average Cost of Supply (in Rs. / kWh)						

(ii) Projected Revenue at current tariff, Projected Aggregate Revenue Requirement and Expected Revenue from Charges at proposed tariff for the ensuing years of the control period are as follows:

Figures in Rs. Lakhs

Particulars	Tariff for the Base year	Tariff for the control period ... (year) to ...... (year)				
		1st year	2nd year	3rd year	4th year	5th year
Projected Revenue at Current Tariff						
Projected Aggregate Revenue Requirement						
Expected Revenue from Charges at Proposed Tariff						
Range of percentage of increase / decrease sought in the application for each of the ensuing year compared to the revenue at current tariff						

(iii) Major reasons for increase/decrease in tariff proposed:

(iv) Major factors not considered in the above increase/decrease sought, if any:

(v) Details of major changes proposed regarding applicable terms and conditions:

(vi) Any other important issue:

(II) True up Application for the Year: **<AS MAY BE APPLICABLE>**

Particulars	Fixed Cost	Variable Cost	Total	Revenue received
	(A)	(B)	(C) = (A) +(B)	(D)
Admitted in the Tariff Order				
Actual as True-up petition				
Incentive, sharing of gain/ loss				
Shortfall / surplus to be adjusted in True-up				

Reasons for variations:

(III) In-Principle Approval: **<AS MAY BE APPLICABLE>**

(a) Brief description of the Scheme:

(b) Estimated project Cost:

(c) Start date of project:

(d) Scheduled completion date of project:

(e) Source of Financing:

(f) Proposed benefits:

3. Application submitted by …………… **<Name of applicant** has been posted in the website of the applicant at ……….. **<Name of the Website>**. Hard Copy of the Complete application submitted before the Commission may be collected at Rs. …… <Fees to be specified by the Commission> per page of copy, from the following offices of the applicant:

   (i) Registered office: <address>…………………….

   (ii) Other offices: <address>

   (iii) …….

4. The suggestions, objections and comments, if any, on the proposal contained in the application may be submitted at the office of the Commission at ……………………….. <Office Address of the Commission> from …. AM till ….. PM within ….. days from the date of publication (including the date of publication) of this notice in the newspaper along with a copy to the applicant at its Registered Office Address.

5. The gist has been published with the approval of the West Bengal Electricity Regulatory Commission.

Name and designation of the submitting proposal

Place:

Date:

By order of the Commission

Sd/-
Deputy Director, WBERC

Place: Kolkata

Date: