CENTRAL ELECTRICITY REGULATORY COMMISSION

NEW DELHI

No.L-1/268/2022/CERC Dated 15th March, 2024

(NOTIFICATION)

In the exercise of powers conferred under section 178 of the Electricity Act, 2003 (36 of 2003) read with Section 61 thereof and all other powers enabling it in this behalf, and after previous publication, the Central Electricity Regulatory Commission hereby makes the following regulations, namely:

CHAPTER – 1

PRELIMINARY

1. **Short title and commencement.** (1) These regulations may be called the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024.

(2) These regulations shall come into force on 1.4.2024, and, unless reviewed earlier or extended by the Commission, shall remain in force for a period of five years from 1.4.2024 to 31.3.2029:

Provided that where a generating station or unit thereof and transmission system or an element thereof, has been declared under commercial operation before the date of commencement of these regulations and whose tariff has not been finally determined by the Commission till that date, tariff in respect of such generating station or unit thereof and transmission system or an element thereof for the period ending 31.3.2024 shall be determined in accordance with the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019 as amended from time to time.

2. **Scope and extent of application**. (1) These regulations shall apply to all cases where tariff for a generating station or a unit thereof and a transmission system or an element thereof is required to be determined by the Commission under section 62 of the Act read with section 79 thereof:

Provided that any generating station for which agreement(s) have been executed for the supply of electricity to the beneficiaries on or before 5.1.2011 and the financial closure for the said generating station has not been achieved by 31.3.2024, such projects shall not be eligible for determination of tariff under these regulations unless fresh consent of the beneficiaries is obtained and furnished;

(2) These regulations shall also apply in all cases where a generating company has the arrangement for the 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 79 thereof.

(3) These regulations shall not apply to the following cases: -

(a) Generating stations or transmission systems whose tariff has been discovered through tariff based competitive bidding in accordance with the guidelines issued by the Central Government and adopted by the Commission under section 63 of the Act;

(b) Generating stations based on renewable sources of energy whose tariff is determined in accordance with the Central Electricity Regulatory Commission (Terms and Conditions for Tariff determination from Renewable Energy Sources) Regulations, 2020.

3. **Definitions.** - In these regulations, unless the context otherwise requires: -

(1) **'Act'** means the Electricity Act, 2003 (36 of 2003);

(2) **'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 transmission licensee, as the case may be, in accordance with the provisions of these regulations;

(3) **'Additional Capitalisation'** means the additional capital expenditure admitted by the Commission after prudence check, in accordance with these regulations;

(4) **'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;

(5) **'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;

(6) **'Ancillary Service'** or **'AS'** in relation to power system operation means the service necessary to support the grid operation in maintaining power quality, reliability and security of the grid and includes Primary Reserve Ancillary Service, Secondary Reserve Ancillary Service, Tertiary Reserve Ancillary Service, active power support for load following, reactive power support, black start and such other services as defined in the Grid Code;

(7) **'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, 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.

(8) **'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 (7) of this Regulation;

(9) **'Auditor'** means an auditor appointed by a generating company or a transmission 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;

(10) **'Beneficiary'** in relation to a generating station covered under clauses (a) or (b) of sub-section 1 of section 79 of the Act, 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.

(11) **'Capital Cost'** means the capital cost as determined in Regulation 19 of these regulations in respect of generating station or transmission system, as the case may be, and Regulation 41 of these regulations in respect of integrated mine(s);

(12) **'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.

(13) **'Commission'** means the Central Electricity Regulatory Commission referred to in sub-section (1) of section 76 of the Act;

(14) **'Communication System'** means communication system as defined in sub clause (h) of clause (i) of Regulation 2 of the Central Electricity Regulatory Commission (Communication System for inter-State transmission of electricity) Regulations, 2017;

(15) **'Competitive Bidding'** means a transparent process for procurement of equipment, services and works in which bids are invited by the project developer 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;

(16) **'Cut-off Date**' shall be 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);

(17) **'Date of Commercial Operation'** or **'COD'** in respect of a thermal generating station or hydro

generating station or transmission system or communication system shall have the same meaning as defined in the Grid Code, as amended from time to time:

Provided that Date of Commercial Operation of integrated mine(s) shall have the same meaning as specified in Regulation 5 of these regulations;

(18) **'Date of Operation' or 'ODe'** in respect of an emission control system means 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 an authorised person, not below the level of Director of the generating company;

(19) **'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;

(20) **'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 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;

(21) **'De-capitalisation'** 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;

(22) **'De-commissioning'** means removal from service of a generating station or a unit thereof or transmission 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;

(23) **'Design Energy'** means the quantum of energy which can be generated in a 90% dependable year with 95% installed capacity of the hydro generating station;

(24) **'Element'** means an asset which has been distinctively defined under the scope of the transmission project in the Investment Approval, such as transmission lines, including line bays and line reactors, substations, bays, compensation devices, Interconnecting Transformers which can be put to use.

(25) **'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;

(26) **'Escrow account'** means the account for deposit and withdrawal of mine closure expenses of integrated mine(s), maintained in accordance with the guidelines issued by the Coal Controller, Ministry of Coal, Government of India;

(27) **'Existing Project'** means the generating station and the transmission system which has been declared under commercial operation on a date prior to 1.4.2024;

(28) **'Expansion project'** shall include any addition of new capacity to the existing generating station or augmentation of the transmission system, as the case may be;

(29) **'Expenditure Incurred'** 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;

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

(31) **'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 transmission licensee from completing or operating the project, and only if such events or circumstances are not within the control of the generating company or transmission licensee and could not have been avoided, had the generating company or transmission 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) Industry wide strikes and labour disturbances having a nationwide impact in India; or

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

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

(33) **'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;

(34) **'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;

(35) **'Grid Code'** means the Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2023;

(36) **'Gross Calorific Value'** or **'GCV'** in relation to a thermal generating station means the heat produced in kCal by the complete combustion of one kilogram of solid fuel or one litre of liquid fuel or one standard cubic meter of gaseous fuel, as the case may be;

(37) **'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:

Provided that the measurement of coal shall be carried out through sampling by a third party agency to be appointed by the generating companies in accordance with the guidelines, if any, issued by the Central Government:

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 the collection, preparation and testing of samples for measurement of GCV in a fair and transparent manner;

(38) **'Gross Station Heat Rate'** or **'SHR'** means the heat energy input in kCal required to generate

one kWh of electrical energy at generator terminals of a thermal generating station;

(39) **'Implementation Agreement'** means any agreement or covenant entered into (i) between the transmission licensee and the generating company or (ii) between the transmission licensee and developer of the interconnected transmission system for the execution of generation and transmission projects in a coordinated manner, laying down the project implementation schedule and mechanism for monitoring the progress of the projects;

(40) **'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;

(41) **'Infirm Power'** means electricity injected into the grid prior to the date of commercial operation of a unit of the generating station in accordance with Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2023;

(42) **'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;

(43) **'Installed Capacity'** or **'IC'** means the summation of the name plate capacities of all the units of the generating station or the capacity of the generating station reckoned at the generator terminals, as may be approved by the Commission from time to time;

(44) **'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.*

(45) **'Inter-State Generating Station'** or **'ISGS'** has the meaning as assigned in the Grid Code;

(46) **'Investment Approval'** means approval by the Board of the generating company or the transmission licensee or Cabinet Committee on Economic Affairs (CCEA) or any other competent authority conveying administrative sanction for the project, including funding of the project and the timeline for the implementation of the project:

Provided that the date of Investment Approval shall be reckoned from the date of the resolution of the Board of the generating company or the transmission licensee where the Board is competent to accord such approval and from the date of sanction letter of competent authority in other cases;

Provided further that in respect of the integrated mine(s), funding and timeline for implementation shall be indicated separately and distinctly in the Investment Approval;

Provided further that where investment approval includes both the generating station and the integrated mine(s), the funding and timeline for implementation of the integrated mine(s) shall be worked out and indicated separately and distinctly in the Investment Approval.

(47) **'Landed Fuel Cost'** means the total cost of coal (including biomass in case of co firing), lignite or the gas/naphtha/liquid fuel delivered at the unloading point of the generating station and shall include the base price or input price, washery charges wherever applicable, transportation cost (overseas or inland or both) and handling cost, charges for third party sampling and applicable

statutory charges;

(48) **'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;

(49) **'Long-Term Customer'** shall have the same meaning as 'Long Term Customer' as defined in the Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009 or Designated ISTS Customers (DICs) or “General Network Access Grantee” or “GNA Grantee” as defined in the Central Electricity Regulatory Commission (Connectivity and General Network Access to the inter-State Transmission System) Regulations, 2022 (excluding those granted “T-GNA”);

(50) **'Maximum Continuous Rating'** or **'MCR'** in relation to a generating unit of the thermal generating station means the maximum continuous output at the generator terminals, guaranteed by the manufacturer at rated parameters, and in relation to a block of a combined cycle thermal generating station means the maximum continuous output at the generator terminals, guaranteed by the manufacturer with water or steam injection (if applicable) and corrected to 50 Hz grid frequency and specified site conditions;

(51) **'Mine Infrastructure'** shall include assets of the integrated mine(s) such as tangible assets used for mining operations, being civil works, workshops, immovable winning 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;

(52) **'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;

(53) **'New Project'** means the generating station or unit thereof or the transmission system or element thereof achieving its commercial operation on or after 1.4.2024;

(54) **'Non-Pit Head Generating Station' or 'Non-Pit Head Power Plant'** means coal and lignite based generating stations other than Pit Head Generating Stations.

(55) **'Operation and Maintenance Expenses' or 'O&M expenses'** means the expenditure incurred for operation and maintenance of the project, or part thereof, and includes the expenditure on manpower, maintenance, repairs and maintenance spares, other spares of capital nature valuing up to Rs. 10 lakhs, additional capital expenditure of an individual asset costing less than Rs. 20 lakhs, consumables, insurance and overheads and fuel other than used for generation of electricity:

Provided that for integrated mine(s), the Operation & Maintenance 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.

(56) **'Original Project Cost'** means the capital expenditure incurred by the generating company or the transmission licensee, as the case may be, within the original scope of the project up to the cut-

off date, and as admitted by the Commission;

(57) **'Peak Rated Capacity'** in respect of integrated mine(s) means the peak rated capacity of the mine, as specified in the Mining Plan;

(58) **'Pit Head Generating Station' or 'Pit Head Power Plant'** means as defined under The Environment (Protection) Rules, 1986.

(59) **'Plant Availability Factor' or '(PAF)'** in relation to a generating station for any period means the average of the daily declared capacities (DCs) for all the days during the period expressed as a percentage of the installed capacity in MW less the auxiliary energy consumption and auxiliary energy consumption for emission control system as per these regulations;

(60) **'Plant Load Factor' or '(PLF)'** in relation to a 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:

$$\text{PLF - } 10000 \text{ x} \sum_{i=1}^{N} \frac{SGi}{[NxICx(100-AUX_n-AUX_{en})]}, \%$$

Where,

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

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

N = Number of time blocks during the period,

AUX_n = 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.

(61) **'Procedure Regulations'** means the Central Electricity Regulatory Commission (Conduct of Business) Regulations, 2023;

(62) **'Project'** means:

i) in the case of a thermal generating station, all components of the thermal generating station and including an integrated coal mine, biomass pellet handling system, pollution control system, and effluent treatment plan, as may be required;

ii) in the case of a hydro generating station, all components of the hydro generating station including the dam, intake water conductor system, power generating station, as apportioned to power generation; and

iii) in case of transmission, all components of the transmission system, including the communication system;

(63) **'Prudence Check'** means scrutiny of the reasonableness of any cost or expenditure incurred or proposed to be incurred in accordance with these regulations by the generating company or the transmission licensee, as the case may be;

(64) **'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;

(65) **'Rated Voltage'** means as specified in the Grid Code;

(66) **'Reference Rate of Interest'** means the one year marginal cost of funds based lending rate (MCLR) of the State Bank of India (SBI) issued from time to time plus 325 basis points;

(67) **'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;

(68) **'Run-of-River Generating Station'** means a hydro generating station which does not have upstream pondage;

(69) **'Run-of-River Generating Station with Pondage'** means a hydro generating station with sufficient pondage for meeting the diurnal variation of power demand;

(70) **'Scheduled Commercial Operation Date' or 'SCOD'** shall mean the date(s) of commercial operation of a generating station or generating unit thereof or transmission system or element thereof and associated communication system as indicated in the Investment Approval or as agreed in power purchase agreement or transmission service agreement as the case may be, whichever is earlier;

(71) **'Scheduled Energy'** means the quantum of energy scheduled by the concerned Load Despatch Centre to be injected into the grid by a generating station for a given time period;

(72) **'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 given by the concerned Load Despatch Centre in accordance with the Grid Code;

(73) **'Schedule Drawal'** for a time block or any period means the schedule of drawal in MW or MWh ex-bus, including the schedule for Ancillary Services given by the concerned Load Despatch Centre;

(74) **'Sharing Regulations'** means Central Electricity Regulatory Commission (Sharing of Transmission Charges and Losses in inter-State Transmission System) Regulations, 2020 as amended from time to time;

(75) **'Small Gas Turbine Generating Station'** means and includes open cycle gas turbine or

combined cycle generating station with gas turbines in the capacity range of 50 MW or below;

(76) **'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;

(77) **'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;

(78) **'Storage Type Generating Station'** means a hydro generating station associated with storage capacity to enable variation of generation of electricity according to demand;

(79) '**Thermal Generating Station'** means a generating station or a unit thereof that generates electricity using fossil fuels such as coal, lignite, gas, liquid fuel or a combination of these as its primary source of energy or co-firing of biomass with coal;

(80) **'Transmission Line'** shall have the same meaning as defined in sub-section (72) of Section 2 of the Act;

(81) **'Transmission Service Agreement'** means the agreement entered into between the transmission licensee and the Designated ISTS Customers or long-term transmission customers or Central Transmission Utility as applicable in accordance with the Sharing Regulations and shall include the Bulk Power Transmission Agreement and Long Term Access Agreement;

(82) **'Transmission System'** means a line or a group of lines with or without associated sub-station, equipment associated with transmission lines and sub-stations identified under the scheme as per the Investment Approval(s) and shall include associated communication system;

(83) **'Trial Operation'** in relation to the transmission system shall have the same meaning as

specified in Regulation 23 of Grid Code;

(84) **'Trial Run'** in relation to the generating station shall have the same meaning as specified in Regulation 22 of Grid Code;

(85) **'Sub-Station'** shall have the same meaning as defined in sub-section (69) of section 2 of the Act;

(86) **'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;

(87) **'Useful Life'** in relation to a unit of a generating station, integrated mines, transmission 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)	Optical Ground Wire (OPGW)	15 years
(h)	IT system, SCADA and Communication system excluding OPGW	7 years
(i)	Integrated mine(s)	As per the Mining Plan

Provided that in the case of coal/lignite based thermal generating stations and hydro generating stations, the Operational Life may be 35 years and 50 years, respectively.

(88) The words and expressions used in these regulations and not defined herein but defined in the Act or any other regulations of the Commission, shall have the meaning assigned to them under the Act or any other regulations of the Commission.

4. **Interpretations:** - In these regulations, unless the context otherwise requires:

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

(2) 'kCal' means a unit of heat energy contents in mineral, measured in one kilo calories or one thousand calories of heat produced at any instantaneous period;

(3) 'Kilowatt-Hour' or 'kWh' means a unit of electrical energy, measured in one kilowatt or one thousand watts of power produced or consumed over a period of one hour;

(4) 'Quarter' means the period of three months commencing on the first day of April, July, October and January of each financial year in case of an existing project, and in case of a new project, in respect of the first quarter, from the date of commercial operation to the last day of June, September, December or March, as the case may be;

(5) 'Tonne' means a metric tonne of coal or lignite in respect of integrated mine(s);

(6) 'Year' means a financial year beginning on 1st April and ending on 31st March:

Provided that the first year in case of a new project or integrated mine(s) shall commence from the date of commercial operation and end on the immediately following 31st March.

(7) Reference to any Act, Rules, and Regulations shall include amendment or consolidation or re-enactment thereof.

CHAPTER – 2

DATE OF COMMERCIAL OPERATION

5. **Date of Commercial Operation:** (1) The date of commercial operation of a generating station or unit thereof or a transmission system or element thereof and associated communication system shall be determined in accordance with the provisions of the Grid Code. In the event of mismatch of COD between associated transmission and/or generating stations, the liability for the transmission charges shall be in accordance with the provisions of the Sharing Regulations, 2020 as amended from time to time.

(2) 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 Regulation 7 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 sub-clauses (a) to (c) of Clause (2) of this Regulation, the generating company shall declare the date of commercial operation of the integrated mine(s) under the relevant sub-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 sub-clauses of Clause (2) of this Regulation;

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.

6. **Sale of Infirm Power:** Supply of infirm power shall be in accordance with the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related matters) Regulations, 2022:

Provided that any revenue earned by the generating company from the supply of infirm power after accounting for the fuel expenses shall be applied in adjusting the capital cost accordingly.

7. **Supply of Coal or Lignite prior to the Date of Commercial Operation of Integrated Mine:** The input price for the supply of coal or lignite from the integrated mine(s) prior to their date of commercial operation shall be:

(a) in the case of coal, the estimated price available in the investment approval, or the notified price of Coal India Limited for the corresponding grade of coal supplied to the power sector, whichever is lower; and

(b) in the case of lignite, the estimated price available in the investment approval or the last available pooled lignite price as determined by the Commission for the transfer price of lignite, whichever is lower:

Provided that any revenue earned from the supply of coal or lignite prior to the date of commercial operation of the integrated mine(s) shall be applied in adjusting the capital cost of the said integrated mine(s).

CHAPTER-3

PROCEDURE FOR TARIFF DETERMINATION

8. Tariff determination

(1) Tariff in respect of a generating station and emission control system, wherever applicable, may be determined for the whole of the generating station or unit thereof, and tariff in respect of a transmission system may be determined for the whole of the transmission system or element thereof or associated communication system:

Provided that:

(i) In case of commercial operation of all the units of a generating station or all elements of a transmission system prior to 1.4.2024, the generating company or the transmission licensee, as the case may be, shall file a consolidated petition in respect of the entire generating station or transmission system for the purpose of determination of tariff for the period from 1.4.2024 to 31.3.2029:

(ii) Tariff of the associated communication system forming part of the transmission system which has achieved commercial operation prior to 1.4.2014 shall be as per the methodology approved by the Commission prior to 1.4.2014.

(iii) The generating company shall file an application for determination of supplementary tariff for the emission control system installed in a coal or lignite based thermal generating station in accordance with these regulations not later than 90 days from the date of operation of such emission control system.

(2) Where only a part of the generation capacity of a generating station is tied up for supplying power to the beneficiaries through a long term power purchase agreement, the units for such part capacity shall be clearly identified and, in such cases, the tariff shall be determined for such identified capacity. Where the unit(s) corresponding to such part capacity cannot be identified, the tariff of the generating station may be determined with reference to the capital cost of the entire project, but the tariff so determined shall be applicable corresponding to the part capacity contracted for supply to the beneficiaries.

(3) In case of expansion of the existing generating station, the tariff shall be determined for the expanded capacity in accordance with these regulations:

Provided that the common infrastructure of the existing generating station, shall be utilized for the expanded capacity and the benefit of new technology in the expanded capacity, as determined by the Commission, shall be extended to the existing capacity.

(4) Assets installed for implementation of the revised emission standards shall form part of the existing generation project, and the tariff thereof shall be determined separately in accordance with the application filed under the 5th proviso to Clause (1) of Regulation 9 of these Regulations.

(5) Energy charge component of the tariff of the generating station getting coal or lignite from the integrated mine shall be determined based on the input price of coal or lignite, as the case may be, from such integrated mines:

Provided that the generating company shall maintain the account of the integrated mine separately and submit the cost of the integrated mine, in accordance with these regulations, duly certified by the Auditor.

(6) Tariff of generating station using coal washery rejects developed by Central or State PSUs or Joint Venture between a Government Company and a company other than a Government Company

shall be determined in accordance with these regulations:

Provided that in case of a Joint Venture between a Government Company and a Company other than the Government Company, the shareholding of the company other than the Government Company either directly or through any of its subsidiary companies or associate companies shall not exceed 26% of the paid up share capital:

Provided further that the energy charge component of the tariff of such generating station or unit thereof shall be determined based on the fixed cost and the variable cost of the coal washery project:

Provided also that the Gross Calorific Value of coal rejects shall be measured jointly by the generating company and the beneficiaries.

(7) In the case of multi-purpose hydro schemes, with irrigation, flood control and power components, the capital cost chargeable to the power component of the scheme only shall be considered for the determination of tariff.

(8) If an existing transmission project is granted a licence under section 14 of the Act, read with clause (c) of Regulation 6 of the Central Electricity Regulatory Commission (Terms and Conditions of grant of Transmission Licence for Inter-State Transmission of electricity and related matters) Regulations, 2009, the tariff of such project shall be applicable from the date of grant of transmission licence or from the date as indicated in the transmission licence, as the case may be. In such cases, the applicant shall file a petition as per Annexure-I (Part III) to these regulations, clearly demarcating the assets which form part of the business of generation and transmission, the value of such assets, source of funding and other relevant details after adjusting the cumulative depreciation and loan repayment, duly certified by the Auditor.

9. **Application for determination of tariff**

(1) The generating company or the transmission licensee may make an application for determination of tariff for a new generating station or unit thereof or transmission system or element thereof in accordance with these Regulations within 90 days from the actual date of commercial operation:

Provided that where the transmission system comprises various elements, the transmission licensee shall file an application for determination of tariff for a group of elements on incurring of expenditure of not less than Rs. 100 Crore or 70% of the cost envisaged in the Investment Approval, whichever is lower, as on the actual date of commercial operation:

Provided further that transmission licensees shall combine the elements of the transmission system in the Investment Approval, which are attaining commissioning during a particular month and declare a single COD for the combined Asset, which shall be the date of the COD of the last element commissioned in that month and such Asset shall be treated as single Asset for tariff purposes.

Provided further that the generating company or the transmission licensee, as the case may be, shall submit an Auditor Certificate and, in case of non-availability of an Auditor Certificate, a Management Certificate duly signed by an authorised person, not below the level of Director of the company indicating the estimated capital cost incurred as on the date of commercial operation and the projected additional capital expenditure for respective years of the tariff period 2024-29:

Provided that for a new generating station or unit thereof or transmission system or element thereof, the applicant, through a specific prayer in its application filed under Regulation 9(1) of these regulations, may plead for an interim tariff, and the Commission may consider granting interim tariff from the date of commercial operation after the first hearing of the application and where such interim tariff of the generating station or unit thereof and the transmission system or element thereof including communication system has been determined based on Management Certificate, the generating company or the transmission licensee shall submit the Auditor Certificate not later than 90 days from the date of Commercial Operation:

Provided also that the generating company shall file an application for determination of supplementary tariff for the emission control system installed in coal or lignite based thermal generating station in accordance with these regulations not later than 90 days from the date of start of operation of such emission control system.

(2) In case of an existing generating station or unit thereof, or transmission system or element thereof, the application shall be made by the generating company or the transmission licensee, as the case may be, by 30.11.2024 , based on admitted capital cost including additional capital expenditure already admitted and incurred up to 31.3.2024 (either based on actual or projected additional capital expenditure) and estimated additional capital expenditure for the respective years of the tariff period 2024-29 along with the true up petition for the period 2019-24 in accordance with the CERC (Terms and Conditions of Tariff) Regulations, 2019.

(3) In case an emission control system is required to be installed in the existing generating station or unit thereof to meet the revised emission standards, an application shall be made for the determination of supplementary tariff (capacity charges or energy charge or both) based on the actual capital expenditure duly certified by the Auditor.

(4) Where the generating company has the arrangement for the supply of coal or lignite from an integrated mine(s) to one or more of its generating stations, the generating company shall file a petition for determination of the input price of coal or lignite for determining the energy charge along with the tariff petitions for one or more generating stations in accordance with the provision of

Chapter 9 of these regulations:

Provided that a generating company with integrated mine(s) shall file a petition for determination of the input price of coal or lignite from the integrated mine(s) not later than 90 days from the date of actual commercial operation of the integrated mine(s) in accordance with these regulations.

(5) In case the generating company or the transmission licensee files the application as per the timeline specified in sub-clause (1) to (4) of this Regulation, carrying cost at the simple interest rate of 1-year SBI MCLR plus 100 basis points shall be allowed from the date of commercial operation of the project:

Provided that in case the generating company or the transmission licensee delays in filing of application as per the timeline specified in sub-clause (1) to (4) of this Regulation, carrying cost shall be allowed to the generating company or the transmission licensee from the date of filing of the application as per Regulation 10(6) and 10(7) of these regulations.

10. **Determination of tariff**

(1) The generating company for a specific generating station or unit thereof or for an integrated mine or the transmission licensee for a transmission system or element thereof, as the case may be, shall file a petition before the Commission as per **Annexure-I** to these regulations containing the details of underlying assumptions for the capital expenditure and additional capital expenditure incurred and projected to be incurred, wherever applicable.

(2) If the petition is deficient in any respect as required under **Annexure-I** to these regulations, the application shall be returned to the generating company or transmission licensee, as the case may be, for resubmission of the petition within one month of the date of return of the application after rectifying the deficiencies as may be pointed out by the staff of the Commission.

(3) If the information furnished in the petition is in accordance with these regulations, the Commission may consider granting an interim tariff of up to ninety per cent (90%) of the tariff claimed in the case of a new generating station or unit thereof or transmission system, or element thereof during the first hearing of the application for billing purposes till the final tariff is determined by the Commission:

Provided that in case the final tariff determined by the Commission is lower than the interim tariff by more than 10%, the generating company or transmission licensee shall return the excess amount recovered from the beneficiaries or long term customers, as the case may be, with simple interest at 1.20 times of the rate worked out on the basis of 1 year SBI MCLR plus 100 basis points prevailing as on 1st April of the financial year in which such excess recovery was made.

(4) In the case of the existing projects, the generating company or the transmission licensee, as the case may be, shall continue to bill the beneficiaries or the long term customers at the capacity charges or the transmission charges, respectively, as approved by the Commission and applicable as on 31.3.2024 for the period starting from 1.4.2024 till approval of final capacity charges or transmission charges by the Commission in accordance with these regulations:

Provided that the billing for energy charges w.e.f. 1.4.2024 shall be as per the operational norms specified in these regulations.

(5) The Commission shall grant the final tariff in the case of existing and new projects after considering the replies received from the respondents and suggestions and objections, if any, received from the general public and any other person permitted by the Commission, including consumers or consumer associations.

(6) Subject to Sub-Clause (7) below, the difference between the tariff determined in accordance with clauses (3) and (5) above and clauses (4) and (5) above, shall be recovered from or refunded to,

the beneficiaries or the long term customers, as the case may be, with simple interest at the rate equal to the 1 year SBI MCLR plus 100 basis points prevailing as on 1st April of the respective year of the tariff period, in a maximum of six equal monthly instalments;

Provided that the bills to recover or refund shall be raised by the generating company or the transmission licensees within 45 days from the issuance of the Order.

Provided further that such interest, including that determined as per sub-clause (7) of this regulation shall be payable till the date of issuance of the Order and no interest shall be allowed or levied during the period of six-monthly instalments.

Provided further that in case where money is to be refunded and there is a delay in the raising of bills by the generating company or transmission licensees beyond 45 days from the issuance of the Order, it shall attract a late payment surcharge as applicable in accordance with these regulations.

(7) Where the capital cost approved by the Commission on the basis of projected additional capital expenditure exceeds the actual trued up additional capital expenditure incurred on a year to year basis by more than 10%, the generating company or the transmission licensee shall refund to the beneficiaries or the long term customers as the case may be, the tariff recovered corresponding to the additional capital expenditure not incurred, as approved by the Commission, along with simple interest at 1.20 times of the rate worked out on the basis of 1 year SBI MCLR plus 100 basis points as prevalent on 1st April of the respective year.

11. **In-principle approval in specific circumstances:** The generating company for a specific generating station or for an integrated mine or the transmission licensee undertaking any additional capitalization on account of change in law events or force majeure conditions may file petition for in-principle approval for incurring such expenditure after prior notice to the beneficiaries or the long term customers, as the case may be, along with underlying assumptions, estimates and justification

for such expenditure if the estimated expenditure exceeds 10% of the admitted capital cost of the project or Rs.100 Crore, whichever is lower.

12. **Truing up of tariff for the period 2019-24:** The tariff of the generating stations, integrated mines, and transmission systems for the period 2019-24 shall be trued up in accordance with the provisions of Regulation 13 of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019 along with the tariff petition for the period 2024-29. The capital cost admitted as on 31.3.2024 based on the truing up shall form the basis of the opening capital cost as on 1.4.2024 for the tariff determination for the period 2024-29.

13. **Truing up of tariff for the period 2024-29:** (1) The Commission shall carry out the truing up exercise for the period 2024-29, along with the tariff petition filed for the next tariff period, for the following:

a) the capital expenditure, including additional capital expenditure incurred up to 31.03.2029 as admitted by the Commission after prudence checks at the time of truing up;

b) the capital expenditure, including additional capital expenditure incurred up to 31.03.2029 on account of Force Majeure and Change in Law as admitted by the Commission;

c) the additional capital expenditure incurred up to 31.03.2029 on account of the Emission Control System as admitted by the Commission.

(2) The input price of coal or lignite from the integrated mine(s) of the generating station(s) for the tariff period 2024-29 shall be trued up for:

a) The capital expenditure, including additional capital expenditure incurred up to 31.03.2029 as admitted by the Commission after prudence check at the time of truing up;

b) the capital expenditure, including additional capital expenditure incurred up to 31.03.2029 on account of Force Majeure and Change in Law, as admitted by the Commission.

c) The Operation and Maintenance expenses in accordance with provisions of Regulation 46 of these Regulations.

(3) The generating company for a specific generating station or for an integrated mine, or the transmission licensee, as the case may be, shall make an application, as per Annexure -I to these regulations, for carrying out truing up exercise in respect of the generating station or a unit thereof or the transmission system or an element thereof by 30.11.2029.

(4) The generating company for a specific generating station or for an integrated mine, or the transmission licensee, as the case may be, may make an application for interim truing up of tariff in the year 2026-27 if the annual fixed cost increases by more than 20% over the annual fixed cost as determined by the Commission for the respective years of the tariff period:

Provided that if the actual additional capital expenditure falls short of the projected additional capital expenditure allowed under provisions of Chapter 7 of these regulations or reduction of tariff on account of change in the rate of interest on loan or income tax rate, the generating company or the transmission licensee, as the case may be, shall not be required to file any interim true up petition for this purpose and shall refund to the beneficiaries or the long term customers, as the case may be, the excess tariff recovered corresponding to the projected additional capital expenditure not incurred or on account of change in the rate of interest on loan or income tax rate, in the same manner as specified in Regulation 10(6) and 10(7) of these regulations, as the case may be under intimation to the Commission:

Provided further that the generating company or the transmission licensee shall submit the complete details along with the calculations of the refunds made to the beneficiaries or the long term customers, as the case may be, at the time of true up.

(5) After truing up, if the tariff or the input price already recovered exceeds or falls short of the tariff or the input price approved by the Commission under these regulations, the generating company or the transmission licensee, shall refund to or recover from, the beneficiaries or the long term customers, as the case may be, the excess or the shortfall amount, in accordance with Regulation 10(6) and 10(7) of these regulations as may be applicable.

Provided that in case of input price of coal and lignite, the generating company shall refund such excess amount or recover the shortfall amount from the beneficiaries based on scheduled energy.

CHAPTER- 4

TARIFF STRUCTURE

14. **Components of Tariff:** (1) The tariff for the supply of electricity from a thermal generating station shall comprise two parts, namely, capacity charge (for recovery of annual fixed cost consisting of the components as specified in Regulation 15 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 16 of these regulations).

(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.

(3) The capacity charge and energy charge of a generating station shall be determined in accordance with the provisions of Chapter 11 of these regulations. The input price of coal or lignite from the integrated mine, as determined in accordance with the provisions of Chapter 9 of these regulations, shall form part of the energy charge of the generating station.

(4) The tariff for the supply of electricity from a hydro generating station shall comprise a capacity charge and an energy charge to be derived in the manner specified in Regulation 65 or 66 of these regulations, as may be applicable, for recovery of the annual fixed cost consisting of the components referred to in Regulation 15 of these regulations.

(5) The tariff for transmission of electricity on inter-State transmission system shall comprise transmission charges for recovery of annual fixed cost consisting of the components specified in Regulation 15 of these regulations.

15. **Capacity Charges:** (1) The capacity charges shall be derived on the basis of annual fixed costs. The Annual Fixed Cost (AFC) of a generating station or a transmission system, including a communication system, shall consist of the following components:

(a) Return on equity;

(b) Interest on loan capital;

(c) Depreciation;

(d) Interest on working capital; and

(e) Operation and maintenance expenses:

Provided that Special Allowance in lieu of R&M, where opted in accordance with Regulation 28 of these regulations, shall be recovered separately and shall not be considered for computation of working capital.

(2) **Supplementary Capacity Charges**: 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 (a) to (e) of Clause (1) of this Regulation.

16. **Energy Charges:** Energy charges shall be derived on the basis of the landed fuel cost (LFC) of a generating station (excluding hydro) and shall consist of the following costs:

(a) Landed Fuel Cost of primary fuel;

(b) Cost of secondary fuel oil consumption; and

(c) Cost of limestone or any other reagent, as applicable:

Provided that any refund of taxes and duties along with any amount received on account of penalties from the fuel supplier shall be adjusted in fuel cost:

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 64 of these regulations.

Provided also that in case of supply of coal or lignite from the integrated mine(s), the landed cost of primary fuel shall be based on the input price of coal or lignite, as the case may be, as computed in accordance with these regulations.

17. **Special Provisions for Tariff for Thermal Generating Station which have Completed 25 Years of Operation from Date of Commercial Operation:** In respect of a thermal generating station that has completed 25 years of operation from the date of commercial operation and the power purchase agreement for supply of electricity to beneficiaries from such generating station is not extended, the generating company and the beneficiary may agree on an arrangement, including provisions for target availability and incentive, where in addition to the energy charge, capacity charges determined under these regulations shall also be recovered based on scheduled generation.

CHAPTER – 5

CAPITAL STRUCTURE

18. **Debt-Equity Ratio:** (1) For new projects, the debt-equity ratio of 70:30 as on date of commercial operation shall be considered. If the equity actually deployed is more than 30% of the capital cost, equity in excess of 30% shall be treated as normative loan:

Provided that:

i. where equity actually deployed is less than 30% of the capital cost, actual equity shall be considered for determination of tariff:

ii. the equity invested in foreign currency shall be designated in Indian rupees on the date of each investment:

iii. any grant obtained for the execution of the project shall not be considered as a part of capital structure for the purpose of debt: equity ratio.

Explanation-The premium, if any, raised by the generating company or the transmission licensee, as the case may be, while issuing share capital and investment of internal resources created out of its free reserve for the funding of the project, shall be reckoned as paid up capital for the purpose of computing return on equity, only if such premium amount and internal resources are actually utilised for meeting the capital expenditure of the generating station or the transmission system.

(2) The generating company or the transmission licensee, as the case may be, shall submit the resolution of the Board of the company or the approval of the competent authority in other cases regarding the infusion of funds from internal resources in support of the utilization made or proposed to be made to meet the capital expenditure of the generating station or the transmission system including communication system, as the case may be.

(3) In the case of the generating station and the transmission system, including the communication system declared under commercial operation prior to 1.4.2024, the debt-equity ratio allowed by the Commission for the determination of tariff for the period ending 31.3.2024 shall be considered:

Provided that in the case of a generating station or a transmission system, including a communication system which has completed its useful life as on 1.4.2024 or is completing its useful life during the 2024-29 tariff period, if the equity actually deployed is more than 30% of the capital cost, equity in excess of 30% shall not be taken into account for tariff computation;

Provided further that in case of projects owned by Damodar Valley Corporation, the debt: equity ratio shall be governed as per sub-clause (ii) of clause (2) of Regulation 96 of these regulations.

(4) In the case of the generating station and the transmission system, including communication system declared under commercial operation prior to 1.4.2024, but where debt: equity ratio has not been determined by the Commission for determination of tariff for the period ending 31.3.2024, the Commission shall approve the debt: equity ratio in accordance with clause (1) of this Regulation.

(5) Any expenditure incurred or projected to be incurred on or after 1.4.2024 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 clause (1) of this Regulation.

(6) Any expenditure incurred for the emission control system during the tariff period as may be admitted by the Commission as additional capital expenditure for determination of supplementary tariff, shall be serviced in the manner specified in clause (1) of this Regulation.

CHAPTER-6

COMPUTATION OF CAPITAL COST

19. **Capital Cost:** (l) The Capital cost of the generating station or the transmission system, as the case may be, as determined by the Commission after prudence checks in accordance with these regulations shall form the basis for the determination of tariff for existing and new projects.

(2) The Capital Cost of a new project shall include the following:

(a) The expenditure incurred or projected to be incurred up to the date of commercial operation of the project;

(b) Interest during construction and financing charges, on the loans (i) being equal to 70% of the funds deployed and, in the event actual equity is in excess of 30% on a pari-passu basis, by treating the excess equity over and above 30% of the funds deployed as a normative loan, or (ii) being equal to the actual amount of the loan in the event of actual equity being less than 30% of the funds deployed;

(c) Any gain or loss on account of foreign exchange risk variation pertaining to the loan amount availed during the construction period;

(d) Interest during construction and incidental expenditure during construction as computed in accordance with these regulations;

(e) Capitalised initial spares subject to the ceiling rates in accordance with these regulations;

(f) Expenditure on account of additional capitalization and de-capitalisation determined in accordance with these regulations;

(g) Adjustment of revenue due to the sale of infirm power in excess of fuel cost prior to the date of commercial operation as specified under Regulation 6 of these regulations;

(h) Adjustment of revenue earned by the transmission licensee by using the assets before the date of commercial operation;

(i) Capital expenditure on account of ash disposal and utilization including handling and transportation facility;

(j) Capital expenditure incurred towards railway infrastructure and its augmentation for transportation of coal up to the receiving end of the generating station but does not include the transportation cost and any other appurtenant cost paid to the railway;

(k) Capital expenditure on account of biomass handling equipment and facilities, for co-firing;

(l) Capital expenditure on account of emission control system necessary to meet the revised emission standards and sewage treatment plant;

(m) Expenditure on account of the fulfilment of any conditions for obtaining environment clearance for the project;

(n) Expenditure on account of change in law and force majeure events; and

(o) Capital cost incurred or projected to be incurred by a thermal generating station, on account of implementation of the norms under the Perform, Achieve and Trade (PAT) scheme of the Government of India shall be considered by the Commission subject to sharing of benefits accrued under the PAT scheme with the beneficiaries.

(p) Expenditure required to enable flexible operation of the generating station at lower loads.

(3) The Capital cost of an existing project shall include the following:

(a) Capital cost admitted by the Commission prior to 1.4.2024 duly trued up by excluding liability, if any, as on 1.4.2024;

(b) Additional capitalization and de-capitalization for the respective year of tariff as determined in accordance with these regulations;

(c) Capital expenditure on account of renovation and modernisation as admitted by this Commission in accordance with these regulations;

(d) Capital expenditure on account of ash disposal and utilization, including handling and transportation facility;

(e) Capital expenditure incurred towards railway infrastructure and its augmentation for transportation of coal up to the receiving end of generating station but does not include the transportation cost and any other appurtenant cost paid to the railway;

(f) Capital cost incurred or projected to be incurred by a thermal generating station, on account of implementation of the norms under the Perform, Achieve and Trade (PAT) scheme of the Government of India shall be considered by the Commission subject to sharing of benefits accrued under the PAT scheme with the beneficiaries;

(g) Expenditure required to enable flexible operation of the generating station at lower loads;

(h) Capital expenditure on account of biomass handling equipment and facilities, for co-firing; and

(i) Expenditure on account of change in law and force majeure events;

(4) The capital cost in case of existing or new hydro generating stations 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; and

(b) cost of the developer's 10% contribution towards the Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) and Deendayal Upadhyaya Gram Jyoti Yojana (DDUGJY) project in the affected area.

(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 Government of India, 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;

(5) 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 Chapter 7 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;

(d) 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 Chapter 7 of these Regulations.

(6) The following shall be excluded from the capital cost of the existing and new projects:

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

(b) De-capitalised Assets after the date of commercial operation on account of obsolescence;

(c) De-capitalised Assets on account of upgradation or shifting from one project to another project:

Provided that in case such an asset is recommended for further utilisation by the Regional Power Committee in consultation with CTU, such asset shall be de-capitalised from the original project only after its redeployment;

Provided further that unless shifting of an asset from one project to another is of a permanent nature, there shall be no de-capitalization of the concerned assets.

(d) In the 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;

(e) Proportionate cost of land of the existing generation or transmission project, as the case may be, which is being used for generating power from a generating station based on renewable energy as may be permitted by the Commission; and

(f) Any grant received from the Central or State Government or any statutory body or authority for the execution of the project that does not carry any liability of repayment.

20. **Prudence Check of Capital Cost:** The following principles shall be adopted for prudence check of capital cost of the existing or new projects:

(1) In the case of the thermal generating station and the transmission system, the prudence check of capital cost shall include scrutiny of the capital expenditure, in light of the capital cost of similar projects based on past historical data, wherever available, reasonableness of the financing plan, interest during construction, incidental expenditure during construction, use of efficient technology, cost over-run and time over-run, procurement of equipment and materials through competitive bidding as given in Regulation 101 below 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, as the case may be, has been prudent in its judgments and decisions in the execution of the project.

(2) The Commission may, for the purpose of vetting of capital cost of hydro generating stations, appoint an independent agency or an expert body:

Provided that the Designated Independent Agency already appointed under the guidelines issued by the Commission under Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2009 shall continue till completion of the assigned project.

(3) Where the power purchase agreement entered into between the generating company and the

beneficiaries provides for the ceiling of actual capital expenditure, the Commission shall take into consideration such ceiling for prudence check.

(4) The generating company or the transmission licensee, as the case may be, shall furnish the capital cost for the execution of the existing and new projects as per Annexure-I to these regulations along with tariff petition for the purpose of creating a database of benchmark capital cost of various components.

21. **Interest During Construction (IDC) and Incidental Expenditure during Construction (IEDC)**

(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 1^{st} April of the respective year.

Provided further that IDC on normative loan, post infusion of actual loan shall be computed based on WAROI for that respective quarter.

(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.

(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, 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.

(4) If the delay in achieving the COD is not attributable to the generating company or the transmission 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.

(5) If the delay in achieving the COD is attributable either in entirety or in part to the generating company or the transmission 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, if any, recovered from the contractor or supplier or agency shall be retained by the generating company or the transmission 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 month 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.

(6) For the purpose of Clauses (4) and (5) of this Regulation, IDC on actual loan and normative loan shall be considered in accordance with the normative debt-equity ratio specified under clause (1) of Regulation 18 of these regulations.

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

(1) 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.

(2) 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 the transmission licensee.

23. **Initial Spares**: Initial spares shall be capitalised as a percentage of the Plant and Machinery

cost, subject to the 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 hydro generating station	-	4.0%
(d)	Transmission system		
(i)	Transmission line	-	1.00%
(ii)	Transmission Sub-station		
	-Green Field	-	4.00%
	-Brown Field	-	6.00%
(iii)	Series Compensation devices and HVDC Station	-	4.00%
(iv)	Gas Insulated Sub-station (GIS)	-	
	-Green Field	-	5.00%
	-Brown Field	-	7.00%
(v)	Communication system	-	3.50%
(vi)	Static Synchronous Compensator	-	6.00%

Provided that:

i. 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 and the transmission licensee, for the purpose of estimating Plant and Machinery Costs, shall submit the break-up of head-wise IDC and IEDC in its tariff application;

ii. 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.

iii. 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.

iv. Initial spares of high voltage underground cables used for the transmission system shall be allowed based on actuals on a case-to-case basis after carrying out due a prudence check.

CHAPTER – 7

COMPUTATION OF ADDITIONAL CAPITAL EXPENDITURE

24. **Additional Capitalisation within the original scope and up to the cut-off date**

(1) The additional capital expenditure in respect of a new project or an existing project incurred or projected to be incurred, 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:

(a) Payment made towards admitted liabilities for works executed up to the cut-off date;

(b) Works deferred for execution;

(c) Procurement of initial capital spares within the original scope of work, in accordance with the provisions of Regulation 23 of these regulations;

(d) Payment against the award of arbitration or for compliance with the directions or order of any statutory authority or order or decree of any court of law;

(e) Change in law or compliance with any existing law which is not provided for in the original scope of work;

(f) 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 capital cost and in case the same work is covered under budgetary support provided by Government of India, the funding of such works shall be adjusted on receipt of such funds;

Provided that such expenditure shall be allowed only if the expenditure is incurred through Indian Governmental Instrumentality; and

(g) 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.

(2) The generating company or the transmission licensee, as the case may be shall submit 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.

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

(1) The additional capital expenditure incurred or projected to be incurred in respect of an existing project or a new project on the following counts within the original scope of work and after the cut-off date may be admitted by the Commission, subject to prudence check:

(a) Payment made against award of arbitration or for compliance with the directions or order of any statutory authority, or order or decree of any court of law;

(b) Change in law or compliance with any existing law which is not provided for in the original scope of work;

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

(d) Payment made towards liability admitted for works within the original scope executed prior to the cut-off date;

(e) Force Majeure events;

(f) Works within original scope executed after the cut-off date and admitted by the Commission, to the extent of actual payments made; and

(2) In case of replacement of assets deployed under the original scope of the existing project after the 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) Assets whose useful life 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) The replacement of the asset or equipment is necessary on account of a change in law or Force Majeure conditions;

(c) The replacement of such asset or equipment is necessary on account of obsolescence of technology; and

(d) The replacement of such asset or equipment has otherwise been allowed by the Commission.

(e) The additional expenditure, excluding recurring expenses covered in O&M expenses, involved in relation to the renewal of lease of lease hold land on case to case basis.

Provided that any claim of additional capitalisation with respect to the replacement of assets under the original scope and on account of obsolescence of technology, less than Rs. 20 lakhs shall not be considered as part of Capital cost and shall be met through normative O&M expenses.

26. Additional Capitalisation beyond the original scope

(1) The capital expenditure, in respect of the existing generating station or the transmission system, including the communication system, incurred or projected to be incurred on the following counts beyond the original scope, may be admitted by the Commission, subject to prudence check:

(a) Payment made against award of arbitration or for compliance of order or directions of any statutory authority, or order or decree of any court of law;

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

(c) Force Majeure events;

(d) Need for higher security and safety of the plant as advised or directed by appropriate Indian Government Instrumentality or statutory authorities responsible for national or internal security;

(e) Deferred works relating to ash pond or ash handling system or raising of ash dyke in addition to the original scope of work, on case to case basis:

Provided also that if any expenditure has been claimed under Renovation and Modernisation (R&M) or repairs and maintenance under O&M expenses, the same shall not be claimed under this Regulation;

(f) Usage of water from the sewage treatment plant in the thermal generating station.

(g) Works required towards biomass handling system to enable biomass co-firing and towards enabling flexible operation of the generating station as may be required.

(h) Works pertaining to Railway Infrastructure and its augmentation for transportation of coal up to the receiving end of the generating station (excluding any transportation cost and any other appurtenant cost paid to railways) that are not covered under Regulation 24, 25 and 27, but shall result in better fuel management and can lead to a reduction in operation costs, or shall have other tangible benefits:

Provided that the generating company shall have to mandatorily seek prior approval of the Commission before implementing such works based on a detailed cost-benefit analysis of such schemes;

(i) Any additional capital expenditure which has become necessary for efficient operation of generating station or transmission system as the case may be, including the works required towards projects acquired through NCLT process. The claim shall be substantiated with the technical justification and cost benefit analysis.

(2) Any claim of additional capitalisation less than Rs. 20 lakhs shall not be considered under Clause (1) of this regulation and shall be met through normative O&M expenses.

(3) In case of de-capitalisation of assets of a generating company or the transmission licensee, as the case may be, the original cost of such asset as on the date of de-capitalisation 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 in cases where an asset forming part of a scheme is de-capitalised and wherein the historical value of such asset is not available, the value of de-capitalisation shall be computed by de-escalating the value of the new asset by 5% per year until the year of capitalisation of the old asset subject to a minimum of 10% of the replacement cost of the asset.

27. Additional Capitalisation on account of Renovation and Modernisation

(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 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 or the transmission licensee:

Provided that the generating company making the applications for renovation and modernization (R&M) shall not be eligible for Special Allowance under Regulation 28 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.

(2) Where the generating company, as the case may be, 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.

(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.

(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 tariff. Expenditure incurred or projected to be incurred and 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. **Special Allowance for Coal-based/Lignite fired Thermal Generating station**

(1) In the case of coal-based/ lignite fired 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 24, 25, 26 and 27 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;

Provided further that special allowance shall also be available for a generating station which has availed the Special Allowance during the tariff period 2009-14 or 2014-19 or 2019-24 as applicable from the date of completion of the useful life.

(2) The Special Allowance admissible to a generating station shall be @ Rs 10.75 lakh per MW per year for the tariff period.

(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.

(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 clause (1) above, and the expenditure incurred or utilized from the special allowance shall be made available to the Commission as and when directed.

29. **Additional Capitalization on account of Revised Emission Standards:** (1) A generating company requiring to incur additional capital expenditure in the existing generating station for compliance with the revised emissions standards shall share its proposal with the beneficiaries and file a petition for undertaking such additional capitalization.

(2) The proposal under clause (1) above shall contain details of the proposed technology as specified by the Central Electricity Authority, scope of the work, phasing of expenditure, schedule of completion, estimated completion cost including foreign exchange component, if any, detailed computation of indicative impact on tariff to the beneficiaries, and any other information considered to be relevant by the generating company.

(3) Where the generating company makes an application for approval of additional capital expenditure on account of the implementation of revised emission standards, 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.

(4) After completion of the implementation of revised emission standards, the generating company shall file a petition for determination of tariff. Any expenditure incurred or projected to be incurred and admitted by the Commission after prudence check based on the reasonableness of the cost and impact on operational parameters shall form the basis of the determination of tariff.

(5) Un-discharged liability, if any, on account of the emission control system shall be allowed as additional capital expenditure during the year it is discharged, subject to prudence check.

CHAPTER-8

COMPUTATION OF ANNUAL FIXED COST

30. **Return on Equity:** (1) Return on equity shall be computed in rupee terms, on the equity base determined in accordance with Regulation 18 of these regulations.

(2) Return on equity for existing project shall be computed at the base rate of 15.50% for thermal generating station, transmission system including communication system and run-of-river hydro generating station and at the base rate of 16.50% for storage type hydro generating stations, pumped storage hydro generating stations and run-of- river generating station with pondage;

(3) Return on equity for new project achieving COD on or after 01.04.2024 shall be computed at the base rate of 15.00% for the transmission system, including the communication system, at the base rate of 15.50% for Thermal generating station and run-of-river hydro generating station and at the base rate of 17.00% for storage type hydro generating stations, pumped storage hydro generating stations and run-of-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 the emission control system, Change in Law, and Force Majeure shall be computed at the base rate of one-year marginal cost of lending rate (MCLR) of the State Bank of India plus 350 basis points as on 1st April of the year, subject to a ceiling of 14%;

Provided further that:

i. In case of a new project, the rate of return on equity shall be reduced by 1.00% for such period as may be decided by the Commission if the generating station or transmission system is found to be declared under commercial operation without commissioning of any of the Free Governor Mode Operation (FGMO), data telemetry, communication system up to load dispatch centre or protection system based on the report submitted by the respective RLDC;

ii. in case of an existing generating station, as and when any of the requirements under (i) above of this Regulation are found lacking based on the report submitted by the concerned RLDC, the rate of return on equity shall be reduced by 1.00% for the period for which the deficiency continues;

iii. in the case of a thermal generating station:

a) rate of return on equity shall be reduced by 0.25% in case of failure to achieve the ramp rate as specified under Regulation 45(9) of IEGC Regulations, 2023.

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 rate specified by Central Electricity Authority, subject to the ceiling of additional rate of return on equity of 1.00%:

31. **Tax on Return on Equity.** (1) The rate of return on equity as allowed by the Commission under Regulation 30 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 the transmission licensee by excluding the income of non-generation or non-transmission business, as the case may be, and the corresponding tax thereon.

Provided that in case a generating company or transmission licensee is paying

Minimum Alternate Tax (MAT) under Section 115JB of the Income Tax Act, 1961, the effective tax rate shall be the MAT rate, including surcharge and cess;

Provided further that in case a generating company or transmission licensee has opted for Section 115BAA, the effective tax rate shall be tax rate including surcharge and cess as specified under Section 115BAA of the Income Tax Act, 1961.

(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)

(3) The generating company or the transmission 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 pertaining to the tariff period 2024-29 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 is paying Minimum Alternate Tax (MAT) under Section 115JB, the generating company or the transmission 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 that in case a generating company or transmission licensee is paying tax under Section 115BAA, the generating company or the transmission 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 Section 115BAA.

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.

32. **Interest on loan capital:** (1) The loans arrived at in the manner indicated in Regulation 18 of these regulations shall be considered gross normative loans for the calculation of interest on loans.

(2) The normative loan outstanding as on 1.4.2024 shall be worked out by deducting the cumulative repayment as admitted by the Commission up to 31.3.2024 from the gross normative loan.

(3) The repayment for each of the years of the tariff period 2024-29 shall be deemed to be equal to the depreciation allowed for the corresponding year or period. In case of de-capitalization of assets, the repayment shall be adjusted by taking into account cumulative repayment on a pro rata basis, and the adjustment should not exceed cumulative depreciation recovered up to the date of de-capitalisation of such asset.

(4) Notwithstanding any moratorium period availed of by the generating company or the transmission licensee, as the case may be, 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.

(5) The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio or allocated loan portfolio;

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, 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 the transmission licensee as a whole shall be considered.

Provided 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 14%;

Provided further that if the generating company or the transmission licensee, as the case may be, does not have any actual loan, then the rate of interest for a loan shall be considered as 1-year MCLR of the State Bank of India as applicable as on April 01, of the relevant financial year.

(6) The interest on the loan shall be calculated on the normative average loan of the year by applying the weighted average rate of interest.

(7) The changes to the terms and conditions of the loans shall be reflected from the date of such re-financing.

33. **Depreciation:** (1) Depreciation shall be computed from the date of commercial operation of a generating station or unit thereof or a transmission system or element thereof including communication system. In the case of the tariff of all the units of a generating station or all elements of a transmission system including the communication system for which a single tariff needs to be determined, the depreciation shall be computed from the effective date of commercial operation of the generating station or the transmission system taking into consideration the depreciation of individual units:

Provided that the effective date of commercial operation shall be worked out by considering the actual date of commercial operation and installed capacity of all the units of the generating station or capital cost of all elements of the transmission system, for which a single tariff needs to be determined.

(2) The value base for the purpose of depreciation shall be the capital cost of the asset admitted by the Commission. In case of multiple units of a generating station or multiple elements of a transmission system, the weighted average life for the generating station or the transmission system shall be applied. Depreciation shall be chargeable from the first year of commercial operation. In the case of commercial operation of the asset for a part of the year, depreciation shall be charged on a pro rata basis.

(3) The salvage value of the asset shall be considered as 10%, and depreciation shall be allowed up to the maximum of 90% of the capital cost of the asset:

Provided that the salvage value for IT equipment and software shall be considered as NIL and 100% value of the assets shall be considered depreciable;

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

Provided also that the capital cost of the assets of the hydro generating station for the purpose of computation of depreciated value shall correspond to the percentage of the sale of electricity under long-term power purchase agreement at regulated tariff:

Provided also that any depreciation disallowed on account of lower availability of the generating station or 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.

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

(5) Depreciation for Existing Projects shall be calculated annually based on the Straight Line Method and at rates specified in Appendix-I to these regulations for the assets of the generating station and transmission system:

Provided that the remaining depreciable value as on 31st March of the year closing after a period of 12 years from the effective date of commercial operation of the generating station or transmission system, as the case may be, shall be spread over the balance useful life of the assets.

Provided further that in the case of an existing hydro generating station, the generating company, with the consent of the beneficiaries, may charge depreciation at a rate lower than that specified in Appendix I and Appendix II to these Regulations to reduce front loading of tariff.

(6) Depreciation for New Projects shall be calculated annually based on the Straight Line Method and at rates specified in Appendix-II to these regulations for the assets of the generating station and transmission system:

Provided 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 of the generating station or the transmission system, as the case may be, shall be spread over the balance useful life of the assets.

Provided further that in the case of a new hydro generating stations, the generating company, with the consent of the beneficiaries, may charge depreciation at a rate lower than that specified in Appendix II to these Regulations to reduce front loading of tariff.

(7) In the case of the existing projects, the balance depreciable value as on 1.4.2024 shall be

worked out by deducting the cumulative depreciation as admitted to by the Commission up to 31.3.2024 from the gross depreciable value of the assets.

(8) The generating company or the transmission licensee, as the case may be, shall submit the details of capital expenditure proposed to be incurred during five years before the completion of useful life along with proper justification and proposed life extension. The Commission, based on prudence check of such submissions, shall approve the depreciation by equally spreading the depreciable value over the balance Operational Life of the generating station or unit thereof or fifteen years, whichever is lower, and in case of the transmission system shall equally spread the depreciable value over the balance useful life of the Asset or 10 years whichever is higher.

(9) In case of de-capitalization of assets in respect of generating station or unit thereof or transmission system or element thereof, the cumulative depreciation shall be adjusted by taking into account the depreciation recovered in tariff by the de-capitalised asset during its useful service.

(10) 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 (1) to (9) of this Regulation.

(11) Depreciation of the emission control system of an existing generating station that is yet to complete its useful life 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 the straight line method at rates specified in Appendix- I to these

regulations;

Provided that the remaining depreciable value as on 31st March of the year closing after a period of 12 years from the date of operation of such emission control system shall be spread over the balance period of thirteen years or balance operational life of generating station, whichever is lower;

Provided also that in case the date of operation of the emission control system is after the 20th year of commercial operation of the generating station or unit thereof, but before the completion of the useful life of the generating station, the depreciation on emission control system (ECS) shall be computed annually from the date of operation of such ECS based on the straight line method, with a salvage value of 10% and the depreciable value shall be recovered till the operational life of the generating station.

(12) In case the date of operation of the emission control system is subsequent to the date of completion of the useful life of generating station commercial operation of the generating station or unit thereof, depreciation of ECS shall be computed annually from the date of operation of such emission control system based on the straight line method, with a salvage value of 10% and recovered over ten years or a period mutually agreed by the generating company and the beneficiaries, whichever is higher.

34. **Interest on Working Capital:** (1) The working capital shall cover:

(a) For Coal-based/lignite-fired thermal generating stations:

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

(ii) Limestone towards stock for 15 days corresponding to the normative annual plant availability.

(iii) Advance payment for 30 days towards the cost of coal or lignite and limestone for generation corresponding to the normative annual plant availability factor;

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

(v) Maintenance spares @ 20% of operation and maintenance expenses, including water charges and security expenses;

(vi) Receivables equivalent to 45 days of capacity charge and energy charge for the sale of electricity calculated on the normative annual plant availability factor; and

(vii) Operation and maintenance expenses, including water charges and security expenses, for one month.

(b) For emission control system of coal or lignite based thermal generating stations:

(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) Receivables equivalent to 45 days of supplementary capacity charge and supplementary energy charge for the sale of electricity calculated on the normative annual plant availability factor;

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

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

(c) For Open-cycle Gas Turbine/Combined Cycle thermal generating stations:

(i) Fuel cost for 15 days corresponding to the normative annual plant availability factor, duly taking into account the mode of operation of the generating station on gas fuel and liquid fuel;

(ii) Liquid fuel stock for 15 days corresponding to the normative annual plant availability factor, and in case of use of more than one liquid fuel, cost of main liquid fuel duly taking into account mode of operation of the generating stations of gas fuel and liquid fuel;

Provided that the above shall only be allowed to generating stations that have facilities to store liquid fuel.

(iii) Maintenance spares @ 30% of operation and maintenance expenses, including water charges and security expenses;

(iv) Receivables equivalent to 45 days of capacity charge and energy charge for the sale of electricity calculated on the normative plant availability factor, duly taking into account the mode of operation of the generating station on gas fuel and liquid fuel;

(v) Operation and maintenance expenses, including water charges and security expenses, for one month.

(d) For Hydro generating station (including Pumped Storage Hydro generating station) and Transmission System:

(i) Receivables equivalent to 45 days of annual fixed cost;

(ii) Maintenance spares @ 15% of operation and maintenance expenses including security expenses; and

(iii) Operation and maintenance expenses, including security expenses for one month.

(2) The cost of fuel in cases covered under sub-clauses (a) and (c) of clause (1) of this Regulation shall be based on the landed fuel cost (taking into account normative transit and handling losses in terms of Regulation 59 of these regulations) by the generating station and gross calorific value of the fuel as per actual weighted average for the preceding financial year in case of each financial year for which tariff is to be determined:

Provided that in the case of a new generating station, the cost of fuel for the first financial year shall be considered based on landed fuel cost (taking into account normative transit and handling losses in terms of Regulation 59 of these regulations) and gross calorific value of the fuel as per actual weighted average for three months, as used for infirm power, preceding date of commercial operation for which tariff is to be determined.

(3) Rate of interest on working capital shall be on a normative basis and shall be considered at the Reference Rate of Interest as on 1.4.2024 or as on 1st April of the year during the tariff period 2024-29 in which the generating station or a unit thereof or the transmission system including communication system or element thereof, as the case may be, is declared under commercial operation, whichever is later:

Provided that in case of truing-up, the rate of interest on working capital shall be considered at Reference Rate of Interest as on 1st April of each of the financial year during the tariff period 2024-29.

(4) Interest on working capital shall be payable on a normative basis, notwithstanding that the generating company or the transmission licensee has not taken a loan for working capital from any

outside agency.

35. **De-Commissioning**

(1) In case a generating station or unit thereof, or a transmission system including communication systems or element thereof after it is certified by CEA or CTU or any other statutory authority, 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 generating company or a transmission 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.

36. **Operation and Maintenance Expenses:**

(1) Thermal Generating Station: Normative Operation and Maintenance expenses of thermal generating stations shall be as follows:

(1) Coal based and lignite fired (including those based on Circulating Fluidised Bed Combustion (CFBC) technology) generating stations, other than the generating stations or units referred to in clauses (2), (4) and (5) of this Regulation:

(in Rs Lakh/MW)

Year	200/210/ 250 MW Series	300/330/ 350 MW Series	500 MW Series	600 MW Series	800 MW Series and above
FY 2024-25	40.92	34.04	27.17	25.78	23.20
FY 2025-26	43.07	35.83	28.60	27.13	24.42
FY 2026-27	45.33	37.71	30.10	28.56	25.70
FY 2027-28	47.71	39.69	31.68	30.06	27.05
FY 2028-29	50.21	41.78	33.34	31.64	28.47

Provided also that operation and maintenance expenses of generating station having a unit size of less than 200 MW not covered above shall be determined on a case-to-case basis.

(2) Tanda TPS:

(in Rs Lakh/MW)

Year	Tanda TPS (Unit 1)
FY 2024-25 to FY 2028-29	42.52

(3) Open Cycle Gas Turbine/Combined Cycle generating stations:

(in Rs Lakh/MW)

Year	Gas Turbine Combined Cycle generating stations other than small gas turbine power generating stations	Agartala GPS	Small gas turbine power generating stations and Tripura Gas Station	Advance F Class Machines
FY 2024-25	18.18	56.48	47.86	32.08
FY 2025-26	19.14	59.44	50.37	33.77
FY 2026-27	20.14	62.57	53.02	35.54
FY 2027-28	21.20	65.85	55.80	37.40
FY 2028-29	22.32	69.31	58.73	39.37

(4) Lignite-fired generating stations:

(in Rs Lakh/MW)

Year	125 MW Sets
FY 2024-25	38.81
FY 2025-26	40.85
FY 2026-27	42.99
FY 2027-28	45.25
FY 2028-29	47.62

(5) Generating Stations based on coal rejects:

(in Rs Lakh/MW)

Year	O&M Expenses
FY 2024-25	38.81
FY 2025-26	40.85
FY 2026-27	42.99
FY 2027-28	45.25
FY 2028-29	47.62

(6) The Water Charges, Security Expenses, Ash Transportation Expenses and Capital Spares for thermal generating stations shall be allowed separately after prudence check:

Provided that water charges shall be allowed based on water consumption depending upon type of plant and type of cooling water system or water agreement with state govt./utilities, and the norms specified by the Ministry of Environment, Forest and Climate Change subject to prudence check. The details regarding the same shall be furnished along with the petition;

Provided further that the generating station shall submit the assessment of the security requirement and estimated expenses along with the petition seeking the determination of tariff;

Provided also that the generating station shall submit the details of year-wise actual capital spares consumed individually costing above Rs. 10 Lakh at the time of truing up with appropriate justification for incurring the same and substantiating that the same is not funded through compensatory allowance as per Regulation 17 of Central Electricity Regulatory Commission

(Terms and Conditions of Tariff) Regulations, 2014 or Special Allowance or claimed as a part of additional capitalisation or consumption of stores and spares and renovation and modernization.

(7) Any additional O&M expenses incurred by the generating company due to any change in law shall be considered at the time of truing up of tariff.

Provided that such impact shall be allowed only in case the overall impact of such change in law event in a year is more than 5% of normative O&M expenses of the project allowed for the year.

(8) In the case of a generating company 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.

(9) 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 @ 5.25% during the tariff period ending on 31st March 2029:

Provided that income generated from the sale of gypsum or other by-products shall be reduced from the operation and maintenance expenses.

(2) Hydro Generating Station:

The following operations and maintenance expense norms shall be applicable for hydro generating stations which have been operational for three or more years as on 1.4.2024:

(in Rs Lakh)

Particulars	FY 2024-25	FY 2025-26	FY 2026-27	FY 2027-28	FY 2028-29
THPS	40,548.78	42,765.88	45,104.19	47,570.36	50,171.37
KHEP	20,749.20	21,883.71	23,080.25	24,342.21	25,673.18

Bairasul	7,856.31	8,285.87	8,738.92	9,216.74	9,720.68
Loktak	8,876.09	9,361.41	9,873.26	10,413.10	10,982.46
Salal	17,208.43	18,149.34	19,141.69	20,188.30	21,292.14
Tanakpur	11,696.62	12,336.16	13,010.67	13,722.05	14,472.34
Chamera-I	14,397.75	15,184.98	16,015.25	16,890.92	17,814.47
Uri-I	11,755.75	12,398.52	13,076.44	13,791.42	14,545.50
Rangit	6,351.54	6,698.82	7,065.09	7,451.39	7,858.82
Chamera-II	12,149.92	12,814.25	13,514.89	14,253.85	15,033.21
Dhauliganga	11,323.06	11,942.18	12,595.14	13,283.81	14,010.13
Dulhasti	17,754.67	18,725.45	19,749.30	20,829.14	21,968.02
Teesta-V	15,193.93	16,024.69	16,900.88	17,824.97	18,799.59
Sewa-II	8,053.42	8,493.76	8,958.17	9,447.98	9,964.57
TLDP III	9,281.92	9,789.43	10,324.68	10,889.21	11,484.60
Chamera III	9,598.50	10,123.32	10,676.83	11,260.61	11,876.31
Chutak	4,259.73	4,492.64	4,738.28	4,997.36	5,270.60
Nimmo Bazgo	4,346.80	4,584.47	4,835.13	5,099.50	5,378.33
Uri II	9,135.41	9,634.91	10,161.71	10,717.33	11,303.32
Parbati III	10,703.93	11,289.19	11,906.45	12,557.46	13,244.07
Kishanganga	13,952.53	14,715.42	15,520.01	16,368.60	17,263.59
TLDP IV	10,697.94	11,282.87	11,899.79	12,550.43	13,236.66
Indira Sagar	15,030.66	15,852.50	16,719.27	17,633.43	18,597.57
Omkareshwar	10,183.66	10,740.48	11,327.73	11,947.10	12,600.34
Nathpa jhakari	48,588.63	51,245.32	54,047.26	57,002.41	60,119.15
Rampur	18,287.58	19,287.49	20,342.08	21,454.32	22,627.39
Koldam	13,113.75	13,830.78	14,587.01	15,384.58	16,225.77
Karcham Wangtoo	12,612.68	13,302.30	14,029.64	14,796.74	15,605.78
Kopili	12,038.46	12,743.93	13,490.73	14,281.29	15,118.18
Khandong I	2,137.15	2,262.39	2,394.96	2,535.31	2,683.88
Khandong II	1,065.60	1,128.04	1,194.15	1,264.12	1,338.20
Doyang	7,540.48	7,982.36	8,450.13	8,945.31	9,469.52
Panyor	16,827.77	17,813.88	18,857.79	19,962.87	21,132.70
Pare	16,383.05	17,343.10	18,359.42	19,435.29	20,574.21
Turial	5,120.13	5,420.17	5,737.79	6,074.03	6,429.97
Maithon	3,261.23	3,439.55	3,627.61	3,825.96	4,035.15
Panchet	3,361.27	3,545.06	3,738.89	3,943.32	4,158.93
Tilaiya	1,027.67	1,083.86	1,143.12	1,205.62	1,271.54
Teesta Urja Ltd.	27,438.21	28,938.46	30,520.73	32,189.51	33,949.55

a) In the case of the hydro generating stations declared under commercial operation on or after 1.4.2024, operation and maintenance expenses of the first year shall be fixed at 3.5% and

5.0% of the original project cost (excluding the cost of rehabilitation & resettlement works, IDC and IEDC) for stations with installed capacity exceeding 200 MW and for stations with installed capacity less than or equal to 200 MW, respectively and shall be subject to annual escalation of 5.47% per annum for the subsequent years.

b) In the case of hydro generating stations which have not completed a period of three years as on 1.4.2024, operation and maintenance expenses for 2024-25 shall be worked out by applying an escalation rate of 5.47% on the applicable operation and maintenance expenses as on 31.3.2024. The operation and maintenance expenses for subsequent years of the tariff period shall be worked out by applying an escalation rate of 5.47% per annum.

c) The Security Expenses, Capital Spares and Insurance expenses arrived through competitive bidding for hydro generating stations shall be allowed separately after prudence check:

Provided that the generating station shall submit the assessment of the security requirement, capital spares and insurance expenses along with its estimated expenses, which shall be trued up based on the details of year-wise actual capital spares consumed, actual insurance and security expenses incurred with appropriate justification.

Provided further that the value of capital spares exceeding Rs. 10 lakh shall only be considered for reimbursement at the time of truing up with appropriate justification for incurring the same and substantiating that the same is not claimed as a part of additional capitalisation or consumption of stores and spares and renovation and modernization.

d) Any additional O&M expenses incurred by the generating company due to any change in law event shall be considered at the time of truing up of tariff.

Provided that such impact shall be allowed only in case the overall impact of such change in law event in a year is more than 5% of normative O&M expenses of the project for the year.

e) In the case of a generating company 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;

f) The operation and maintenance expenses of the generating station and the transmission system of Bhakra Beas Management Board (BBMB) and Sardar Sarovar Project (SSP) shall be determined after taking into account provisions of the Punjab Reorganization Act, 1966 and Narmada Water Scheme, 1980 under Section-6 A of the Inter-State Water Disputes Act, 1956 respectively.

(3) Transmission system: (a) The following normative operation and maintenance expenses shall be admissible for the transmission system:

Particulars	**2024-25**	**2025-26**	**2026-27**	**2027-28**	**2028-29**
Norms for sub-station Bays (Rs Lakh per bay)					
765 kV	41.34	43.51	45.79	48.20	50.73
400 kV	29.53	31.08	32.71	34.43	36.23
220 kV	20.67	21.75	22.90	24.10	25.36
132 kV and below	15.78	16.61	17.48	18.40	19.35
Norms for Transformers/Reactors (Rs Lakh per MVA or MVAR)					
O&M expenditure per MVA or per MVAr (Rs Lakh per MVA or per MVAr)	0.262	0.276	0.290	0.305	0.322
Norms for AC and HVDC lines (Rs Lakh per km)					
Single Circuit (Bundled Conductor with six or more sub-conductors)	0.861	0.906	0.953	1.003	1.056
Single Circuit (Bundled conductor with four or more sub-conductors)	0.738	0.776	0.817	0.860	0.905
Single Circuit (Twin & Triple Conductor)	0.492	0.518	0.545	0.573	0.603
Single Circuit (Single Conductor)	0.246	0.259	0.272	0.287	0.302
Double Circuit (Bundled Conductor with four or more sub-conductors)	1.291	1.359	1.430	1.506	1.585
Double Circuit (Twin & Triple Conductor)	0.861	0.906	0.953	1.003	1.056
Double Circuit (Single Conductor)	0.369	0.388	0.409	0.430	0.453
Multi Circuit (Bundled Conductor with four or more sub-conductor)	2.266	2.385	2.510	2.642	2.781

Multi Circuit (Twin & Triple Conductor)	1.509	1.588	1.671	1.759	1.851
Norms for HVDC stations					
HVDC Back-to-Back stations (Rs Lakh per MW)	2.07	2.18	2.30	2.42	2.55
Gazuwaka BTB (Rs Lakh/MW)	1.83	1.92	2.03	2.13	2.24
HVDC bipole scheme (Rs Lakh/MW)	1.04	1.10	1.16	1.22	1.28

Provided that the O&M expenses for the GIS bays shall be allowed as worked out by multiplying 0.70 of the O&M expenses of the normative O&M expenses for bays;

Provided that the O&M expense norms of Double Circuit quad AC line shall be applicable to for HVDC bi-pole line;

Provided that the O&M expenses of ±500 kV Mundra-Mohindergarh HVDC bipole scheme (2500 MW) shall be allowed as worked out by multiplying 0.80 of the normative O&M expenses for HVDC bipole scheme;

Provided further that the O&M expenses for Transmission Licensees whose transmission assets are located solely in NE Region (including Sikkim), States of Uttarakhand, Himachal Pradesh, the Union Territories of Jammu and Kashmir and Ladakh, district of Darjeeling of West Bengal shall be worked out by multiplying 1.50 to the normative O&M expenses prescribed above.

(b) The total allowable operation and maintenance expenses for the transmission system shall be calculated by multiplying the number of substation bays, transformer capacity of the transformer/reactor/Static Var Compensator/Static Synchronous Compensator (in MVA/MVAr) and km of line length with the applicable norms for the operation and maintenance expenses per bay, per MVA/MVAr and per km respectively.

(c) **Communication system:** The operation and maintenance expenses for the ULDC or such similar scheme shall be worked out at 2.0% of the original project cost related to such communication system. The transmission licensee shall submit the actual operation and maintenance expenses for truing up. The expenses in case of U-NMS shall be allowed on actual basis after due prudence check.

(d) The Security Expenses, Capital Spares individually costing more than Rs. 10 lakh and Insurance expenses arrived through competitive bidding for the transmission system and associated communication system shall be allowed separately after prudence check:

Provided that in case of self insurance, the premium shall not exceed 0.09% of the GFA of the assets insured;

Provided that the transmission licensee shall submit the along with estimated security expenses based on assessment of the security requirement, capital spares and insurance expenses, which shall be trued up based on details of the year-wise actuals along with appropriate justification for incurring the same and along with confirmation that the same is not claimed as a part of additional capitalisation or consumption of stores and spares and renovation and modernization.

(e) On the occurrence of any change in law event affecting O&M expenses, the impact shall be allowed to the transmission licensee at the time of truing up of tariff.

Provided that such impact shall be allowed only in case the overall impact of such change in law event in a year is more than 5% of normative O&M expenses of the project for the year.

(f) In case of a transmission 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.

CHAPTER – 9

COMPUTATION OF INPUT PRICE OF COAL AND LIGNITE FROM INTEGRATED MINE

37. **Input Price of coal and lignite for energy charges:** (1) Where the generating company has the arrangement for supply of coal or lignite from the integrated mine(s) allocated to it for use in one or more of its generating stations as end use, the energy charge component of tariff of the generating station shall be determined based on the input price of coal or lignite, as the case may be, from such integrated mines in accordance with these regulations.

(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:

Provided 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, the quantity of coal billed shall be adjusted in accordance with Clause (4) of this Regulation.

(3) The generating company shall, after the date of commercial operation of the integrated mine(s), till the input price of lignite is determined by the Commission under these regulations, fix the input price of lignite for the generating station at the last available pooled lignite price as determined by the Commission for transfer price of lignite or the estimated price available in the investment approval, whichever is lower:

Provided that the difference between the input price of lignite determined under these regulations and the input price of lignite so fixed prior to such determination, for the quantity of lignite billed, shall be adjusted in accordance with Clause (4) of this Regulation.

(4) In case of excess or short recovery of input price under Clauses (2) or (3) of this Regulation, 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 1-year SBI MCLR plus 100 basis points prevailing as on 1st April of the respective year of the tariff period, in six equal monthly instalments.

Provided that such interest shall be payable till the date of issuance of the Order and no interest shall be allowed or levied during the period of six-monthly instalments.

Provided that in case there is a delay in filing the Petition for determination of input price as per the timelines specified under Regulation 9 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 simple interest rate of 1-year SBI MCLR plus 100 bps shall be allowed from the date of filing of the Petition.

38. **Input Price of coal or Lignite:** (1) Input price of coal or lignite 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 the input price of lignite shall be computed based on Run of Mine (ROM) based on the technology such as bucket excavator-conveyor or belt-spreader or its combination and handling charges, if any.

(2) Statutory Charges, as applicable, shall be allowed.

39. **Run of Mine (ROM) Cost:** (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 41 and additional capital expenditure under

Regulation 42 shall not be admissible for the purpose of ROM cost in respect of integrated mine(s) allocated through the auction route.

(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 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) 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.

(3) Run of Mine Cost of lignite in case of integrated mine(s) for lignite shall be worked out as under:

ROM Cost = [(Annual Extraction Cost / (ATQ or Actual production whichever is higher) + (Mining Charge)]

Where,

(i) Annual Extraction Cost is the cost of extraction of lignite as computed in accordance with Regulation 43 of these regulations; and

(ii) Mining Charge is the charge per tonne of lignite paid by the generating company to the Mine Developer and Operator engaged by the generating company for mining, wherever applicable.

(4) The generating company shall adhere to the Mining Plan for the extraction of coal or lignite 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.

(5) Run of Mine Cost of coal and lignite shall be worked out in terms of Rupees per tonne.

40. **Additional Charges:** (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 or lignite in a tonne crushed or transported or handled or washed, as the case may be, during the year duly certified by the Auditor.

(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.

(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.

(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.

(5) The crushing charges, transportation charges, handling charges, and washing charges shall be worked out in terms of Rupees per tonne.

41. **Capital Cost:** (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.

(2) Capital expenditure incurred shall be admitted by the Commission after a prudence check.

(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.

(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.

(5) In the case of integrated mine(s) which have declared the date of commercial operation prior to 1.4.2024, the capital expenditure allowed by the Commission for the period ending 31.3.2024 shall form the basis for the computation of input price.

42. **Additional Capital Expenditure:** (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.

(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.

(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 sub-clause (g) of Clause (1) or sub-clause (e) of Clause (2) of this Regulation;

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.

43. **Annual Extraction Cost:** 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.

44. **Capital Structure, Return on Equity and Interest on Loan:** (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 under Clause (1) of Regulation 18 of these regulations:

Provided that for integrated mine(s) in respect of lignite with the date of commercial operation prior to 1.4.2024, the debt-equity ratio allowed by the Commission for the period ending 31.3.2024 shall form the basis for computation of input price.

(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 under Clause (1) of this Regulation.

(3) Return on equity shall be computed in rupee terms on the equity base arrived under Clause (1) of this Regulation at the base rate of 14%.

(4) The base rate of return on equity as per Clause (3) of this Regulation shall be grossed up with the effective tax rate computed in the manner specified under Regulation 31 of these regulations.

(5) Interest on loan, including normative loan, if any, determined under Clause (1) of this Regulation, shall be arrived at by considering the weighted average rate of interest calculated on the basis of the actual loan portfolio, in accordance with Clauses (2) to (7) of Regulation 32 of these regulations.

45. **Depreciation:** (1) Depreciation in respect of integrated mine(s) shall be computed from the date of commercial operation by applying the Straight Line Method:

Provided that depreciation methodology allowed in respect of integrated mine(s) of lignite which have been declared under commercial operation on or before 31.3.2024, shall continue to apply for determination of input price of lignite.

(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.

(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.

(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 Appendix 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.

46. **Operation and Maintenance Expenses:** (1) The Operation and Maintenance Expenses in respect of integrated mine(s) shall be allowed as under:

(a) The Operation and Maintenance expenses in respect of integrated mine(s) of coal, for the tariff period ending on 31st March 2029 shall be allowed based on the projected Operation and Maintenance Expenses for each year of the tariff period subject to prudence check by the Commission;

Provided that the Operation and Maintenance expenses allowed under this clause shall be trued up based on actual expenses for the tariff period ending on 31st March 2029.

(b) The Operation and Maintenance expenses for the tariff period ending on 31st March 2029 in respect of the integrated mine(s) of lignite commissioned on or before 31st March 2024 shall be worked out based on the Operation and Maintenance expenses as admitted by the Commission during 2023-24 and escalated at the rate of 5.25 % per annum;

(c) The Operation and Maintenance expenses for the tariff period ending on 31st March 2029 in respect of the integrated mine(s) of lignite commissioned after 31st March 2024 shall be allowed based on the projected Operation and Maintenance Expenses for each year of the tariff period, subject to prudence check by the Commission;

Provided that the Operation and Maintenance expenses allowed under this clause shall be trued up based on actual expenses for the tariff period ending on 31st March 2029.

(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 Clause (1) of this Regulation;

(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 clause (1) of this Regulation, subject to a prudence check by the Commission.

47. **Interest on Working Capital:** (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.

(2) The working capital of the integrated mine(s) of lignite shall cover: -

(i) Input cost of lignite stock for 7 days of production corresponding to the Annual Target Quantity for the year;

(ii) Consumption of stores and spare including explosives, lubricants and fuel @20%

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 or 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.

(3) The rate and payment of interest on working capital shall be determined in accordance with Clauses (3) and (4) of Regulation 34 of these regulations.

48. **Mine Closure Expenses:** (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 tariff period 2024-29, the shortfall or excess shall be carried forward to the subsequent years for adjustments.

(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.

(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 32 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;

(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 Clause (1) of

this Regulation and mine closure during the period undertaken by the Mine Developer and Operator shall be in accordance with Clause (3) of this Regulation:

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.

(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.

49. **Determination of Input Price:** (1) The input price of coal or lignite shall be determined as under:

Input Price = [ROM Cost + Additional charges]

(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.

(3) Statutory Charges, as applicable, shall be allowed.

50. **Recovery of Input Charges:** (1) The input charges of coal or lignite shall be recovered as under:

Input Charges = [Input Price x Quantity of coal or lignite supplied] + Statutory charges, as applicable;

Provided that where the energy charge rate based on the input price of coal from integrated mine(s) exceeds 20% of the energy charge rate based on the notified price of Coal India Limited for the commensurate grade of coal in a month, prior consent of the beneficiary(ies) shall be required to be obtained by the generating company;

Provided further that where such consents of beneficiaries are not available, the input price of coal from such integrated mine(s) shall be so fixed that the energy charge rate based on the input price of coal from integrated mine(s) does not exceed by more than 20% of the energy charge rate based on the notified price of Coal India Limited for the commensurate grade of coal in a month;

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.

(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.

51. **Adjustment on account of Shortfall of Overburden Removal (OB Adjustment):**

(1) The generating company shall remove overburden as specified in the Mining Plan.

(2) In case of a shortfall of overburden removal during a year, the generating company shall be allowed to adjust such shortfall against excess of overburden removal, if any, during the subsequent three years.

(3) In case of excess of overburden removal during a year, the generating company shall be allowed to carry forward such excess for adjustment against the shortfall, if any, during the subsequent three years.

(4) Where the shortfall of overburden removal of any year is not made good by the generating company in accordance with Clause (2) of this Regulation, the adjustment on account of the shortfall of overburden removal (OB Adjustment) for that year shall be worked out as under:

OB Adjustment = [Factor of adjustment for shortfall of overburden removal during the year] x [Mining Charge during the year + Operation and Maintenance expenses during the year]

Where,

i) Factor of adjustment for the shortfall of overburden removal during the year shall be computed as under:

[(Actual quantity of coal or lignite extracted during the year x Annual Stripping Ratio as per Mining Plan) - (Actual quantity of overburden removed during the year/ Annual Stripping Ratio as per Mining Plan)]/ (Annual Target Quantity);

ii) Annual Stripping ratio is the ratio of the volume of overburden to be removed for one unit of coal or lignite as specified in the Mining Plan.

iii) Mining Charge is the charge per tonne of coal or lignite paid by the generating company to the Mine Developer and Operator engaged by the generating company for mining, wherever applicable.

iv) Mining Charge and Operation and Maintenance expenses shall be in terms of Rupees per tonne corresponding to the Annual Target Quantity.

(5) The provisions of this Regulation regarding adjustment on account of shortfall of overburden removal shall not be applicable in case of the integrated mine(s) allocated through an auction route under the Coal Mines (Special Provisions) Act, 2015.

52. **Adjustment on account of shortfall in GCV (GCV Adjustment):** (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.

(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.

53. **Adjustment on account of Non-tariff income (NTI Adjustment):** (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 = (2/3) x (Total Non-tariff income during the year)/(Actual quantity of coal or lignite extracted during the year)

(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.

54. **Credit Adjustment Note:** (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.

(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 or lignite supplied in that year;

(ii) GCV Adjustment for the year X Quantity of coal or lignite supplied in that year; and

(iii) NTI Adjustment in the year X Quantity of coal or lignite supplied in that year.

(3) The amount in the Credit Adjustment Note shall be adjusted against the charges of coal or lignite 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.

55. **Quality Measurement:** 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.

56. **Special Provision:** Provisions of Chapters 5 to 8 of these regulations shall not be applicable in case of integrated mine(s), except to the extent specifically provided for or referred to in Chapter-9:

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 Chapter-9, shall be considered as per provisions of these regulations as applicable to the coal or lignite based generating stations.

CHAPTER – 10

COMPONENTS OF ENERGY CHARGE

57. **Energy Charges and Supplementary Energy Charges:** The energy charge and Supplementary Energy Charges in respect of the thermal generating Stations shall comprise the landed cost of primary fuel, secondary fuel oil consumption and reagents on account of the implementation of the revised emission standards.

58. **Landed Fuel Cost of Primary Fuel:** 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:

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 in the case of coal-fired or lignite 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.

59. **Transit and Handling Losses:** For coal and lignite, the transit and handling losses shall be as per the following norms: -

Thermal Generating Station	Transit and Handling Loss(%)
Pit head	0.20%
Non-pit head – All	0.80%

Rail route	
Non-pit head multi-modal transportation (using two or more than two mode of transport involving multiple trans-shipments)	1.00%

Provided that in the 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 and handling losses applicable for non-pit head stations shall apply;

Provided further that in case of imported coal, the transit and handling losses applicable for pit-head station shall apply.

60. **Gross Calorific Value of Primary Fuel:** (1) The gross calorific value for computation of energy charges as per Regulation 64 of these regulations shall be done in accordance with 'GCV as Received';

(2) 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 in accordance with the guidelines, if any, issued by the Central Government and the generating company 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 in the absence of third party sampling, computation of the energy charges as per Regulation 64 of these Regulations shall be done in accordance with 'GCV as Billed';

(3) 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.

(4) No loss in calorific value between 'GCV as billed' and 'GCV as received' shall be admissible for generating stations procuring coal through import.

(5) 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.

61. **Landed Cost of Reagent:** (1) 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.

(2) The normative consumption of specific reagents for the various technologies installed for meeting revised emission standards shall be as specified in Regulation 70 of these regulations.

CHAPTER – 11

COMPUTATION OF CAPACITY CHARGES AND ENERGY CHARGES

62. **Computation and Payment of Capacity Charge for Thermal Generating Stations:**

(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 a 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:

(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,

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 $\{(0.20\ x\ AFC)\ x\ (5/6)\}]$

$- (CC_{p1} + CC_{p2} + CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6} + CC_{p7} + CC_{p8} + CC_{p9})$

$CC_{p11} = [(0.20\ x\ AFC)\ x\ (11/12)\ x\ (PAFM_{p12}/NAPAF)$ 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 $(0.20\ x\ AFC)] - (CC_{p1} + CC_{p2} +$ $CC_{p3} + CC_{p4} + CC_{p5} + CC_{p6} + CC_{p7} + CC_{p8} + CC_{p9} + CC_{p10} + CC_{p11})$

$CC_{op1} = (0.80\ x\ AFC)\ x\ (1/12)\ x\ (PAFM_{op1}/NAPAF)$ 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* ($PAFM_{op12}$/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})

Provided that in case generating station or unit thereof is under shutdown due to Renovation and Modernisation or installation of emission control system, as the case may be, the generating company shall be allowed to recover O&M expenses and interest on loan only.

Where,

CC_m= Capacity Charge for the Month;

CC_P= Capacity Charge for the Peak Hours of the Month;

CC_{op}= Capacity Charge for the Off-Peak Hours of the 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 up to the end of n^{th} Month;

$PAFM_{opn}$= Plant Availability Factor achieved during Off-Peak Hours up to the end of n^{th} Month;

NAPAF= Normative Annual Plant Availability Factor.

(3) Normative Plant Availability Factor for "Peak" and "Off-Peak" Hours in a month shall be equivalent to the NAPAF specified in Clause (A) of Regulation 70 of these regulations. The number of hours of "Peak" and "Off-Peak" periods during a day shall be four and twenty, respectively. The hours of Peak and Off-Peak periods during a day shall be declared by the concerned RLDC at least a week in advance.

Provided that RLDC, after duly considering the comments of the concerned stakeholders, shall declare Peak Hours in such a way as to coincide with the majority of the Peak Hours of the region to the maximum extent possible:

Provided further that in respect of a generating station having beneficiaries across different regions, the Peak Hours shall correspond to Peak Hours of the region in which the majority of its beneficiaries, in terms of percentage of allocation of share, are located.

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.

(4) The Plant Availability Factor for a Month ('PAFM') shall be computed in accordance with the following formula:

$$PAFM = 10000\ x \sum_{i=1}^{n} \frac{DCi}{[N\ x\ IC\ x\ (100 - AUXn - AUXen)]} \%$$

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 i^{th} day of the period i.e. the month or the year, as the case may be, as certified by the concerned load dispatch centre after the day is over;

IC = Installed Capacity (in MW) of the generating station;

n = Number of days during the period;

Note: DCi and IC shall exclude the capacity of generating units not declared under commercial operation. In case of a change in IC during the concerned period, its average value shall be taken.

(5) In addition to the AFC entitlement as computed above, the thermal generating station shall be allowed an incentive of up to 1.00% of AFC approved for a given year, which shall be billed monthly as per the following.

Incentive = (1.00% x ß x CC_y)/12

Where,

ß = Average Monthly Frequency Response Performance for that generating station, as certified by RPCs, which shall be computed by considering primary response as per the methodology prescribed by the NLDC with approval of the Commission, and ß shall range between 0 to 1.

Provided that the incentive shall be payable only if the Beta value is higher than 0.30.

CC_y= Capacity Charges for the Year.

(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 Normative Annual Plant Load Factor (NAPLF) achieved on a cumulative basis, as specified in Clause (B) of Regulation 70 of these regulations.

63. **Computation and Payment of Supplementary Capacity Charge for Coal or Lignite based Thermal Generating Stations:**

(1) 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.

(2) 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)] - $(SCC_1 + SCC_2 + SCC_3 + SCC_4 + SCC_5 + SCC_6 + SCC_7 + SCC_8 + SCC_9 + SCC_{10} + SCC_{11})$

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.

Where,

SCC_n= Supplementary Capacity Charge for the n^{th} Month;

AFCe = Annual Fixed Cost of the emission control system;

$PAFM_n$= Plant Availability Factor achieved up to the end of n^{th} Month;

NAPAF= Normative Annual Plant Availability Factor.

(3) Normative Plant Availability Factor for a month for the purpose of Supplementary Capacity Charge shall be considered in the manner specified in Clause (3) of Regulation 62 of these regulations. The PAFM shall be worked out in accordance with Clause (4) of Regulation 62 of these regulations.

64. **Computation and Payment of Energy Charge for Thermal Generating Stations and Supplementary Energy Charge for Coal or Lignite based Thermal Generating Stations:**

(1) The energy charge shall cover the primary and secondary fuel cost and limestone consumption cost (where applicable) 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 and limestone price adjustment). The total Energy charge payable to the generating company for a month shall be:

Energy Charges = (Energy charge rate in Rs./kWh) x {Scheduled energy (ex bus) for the month in kWh}

(2) The supplementary energy charge on account of the emission control system shall cover the differential energy charges 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. The total supplementary energy charge payable to the generating company for a month shall be:

Supplementary Energy Charges = (Supplementary energy charge rate in Rs./kWh) x {Scheduled energy (ex-bus) for the month in kWh}

(3) Energy charge rate (ECR) and Supplementary Energy charge rate in Rupees per kWh on ex-power plant basis shall be determined to three decimal places in accordance with the following formulae:

(a) ECR for coal based and lignite fired stations:

ECR = [{(SHR - SFC x CVSF) x LPPF / CVPF} + (SFC x LPSFi) + (LC x LPL)] x 100

/(100 - AUX)

(b) Supplementary ECR for coal and lignite based thermal generating stations:

Supplementary ECR = (ΔECR) + [(SRC x LPR / 10)/(100-(AUX_n + AUX_{en}))]

(c) For gas and liquid fuel based stations:

ECR = SHR x LPPF x 100/ {(CVPF) x (100 - AUX)}

Where,

AUX =Normative auxiliary energy consumption in percentage.

CVPF = (a) Weighted Average Gross calorific value of coal considering GCV as per Regulation 60, in kCal per kg for coal based stations less 85 Kcal/Kg on account of variation during storage at generating station;

(b) Weighted Average Gross calorific value of primary fuel as received, in kCal per kg, per litre or per standard cubic meter, as applicable for lignite, gas and liquid fuel based stations;

(d) In the 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 Rupees per kWh sent out;

SHR = Gross station heat rate, in kCal per kWh;

LC = Normative limestone consumption in kg per kWh;

LPL = Weighted average landed cost of limestone in Rupees per kg;

LPPF = Weighted average landed fuel cost of primary fuel, in Rupees per kg, per litre or per standard cubic metre, as applicable, during the month. (In case of blending of fuel from different sources, the weighted average landed fuel cost of primary fuel shall be arrived in proportion to the blending ratio);

SFC = Normative Specific fuel oil consumption, in ml per kWh;

LPSFi = Weighted Average Landed Fuel Cost of Secondary Fuel in Rs./ml during the month;

(ΔECR) = Difference between ECR with revised auxiliary energy consumption with emission control system equivalent to (AUX_n + AUX_{en}) and ECR with normative auxiliary energy consumption as specified in these regulations;

SRC = Specific reagent consumption on account of revised emission standards (in g/kWh);

LPR = Weighted average landed price of reagent for the emission control system (in Rs./kg).

Provided that the energy charge rate for a gas or liquid fuel based station shall be adjusted for open cycle operation based on certification of the Member Secretary of the respective Regional Power Committee during the month.

In case of part or full use of an alternative source of fuel supply by coal based thermal generating stations other than as agreed by the generating company and beneficiaries in their power purchase agreement for the supply of contracted power on account of a shortage of fuel or optimization of economical operation through blending, the use of an alternative source of fuel supply shall be permitted to generating station:

Provided that the weighted average price of alternative source of fuel shall not exceed 30% of base price of fuel computed as per clause (5) of this Regulation and in such case, prior permission from beneficiaries shall not be a pre-condition, unless otherwise agreed specifically in the power purchase agreement:

Provided further 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 for that year or exceeds 20% of energy charge rate for 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.

(4) Notwithstanding anything contained in clause 3 of this Regulation, the Commission after considering the shortage of fuel, may vary through separate Order(s), the blending ratio and the requirement of beneficiary consent thereof, towards use of alternative source of fuel..

(5) 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. The energy charge rate of the blended fuel shall be worked out considering the consumption of biomass based on the blending ratio as specified by the Authority or the actual consumption of biomass, whichever is lower.

(6) 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 Commission from time to time under competitive bidding guidelines.

(7) The tariff structure as provided in Regulation 63 and Regulation 64 of these regulations may be adopted by the Department of Atomic Energy, Government of India, for the nuclear generating stations by specifying annual fixed cost (AFC), normative annual plant availability factor (NAPAF), installed capacity (IC), normative auxiliary energy consumption (AUX) and energy charge rate (ECR) for such stations.

65. **Computation and Payment of Capacity Charge and Energy Charge for Hydro Generating Stations:**

(1) The fixed cost of a hydro generating station shall be computed on an annual basis, based on norms specified under these regulations, and shall be recovered on a 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 the home State:

Provided that during the period between the date of commercial operation of the first unit of the generating station and the date of commercial operation of the generating station, the annual fixed cost shall provisionally be worked out based on the latest estimate of the completion cost for the generating station, for the purpose of determining the capacity charge and energy charge payment during such period.

(2) The capacity charge (inclusive of incentive) payable to a hydro generating station for a calendar month shall be:

AFC x 0.5 x NDM / NDY x (PAFM / NAPAF) (in Rupees)

Where,

AFC = Annual fixed cost specified for the year, in Rupees

NAPAF = Normative 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

(3) The PAFM shall be computed in accordance with the following formula:

$$\text{PAFM} = 10000 \text{ x} \sum_{i=1}^{N} \frac{\text{DCi}}{\{\text{N x IC x }(100 - \text{AUX})\}} \%$$

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 for at least three (3) hours, as certified by the nodal load dispatch centre after the day is over.

IC = Installed capacity (in MW) of the complete generating station

N = Number of days in the month

(4) In addition to the AFC entitlement as computed above, the hydro generating station shall be allowed an incentive of up to 3% of the Capacity Charge approved for a given year which shall be billed monthly as per the following.

Incentive = (3% x ß x CC_y)/12

Where,

ß = Average Monthly Frequency Response Performance for that generating station, as certified by RPCs, which shall be computed by considering primary response as per the methodology prescribed by the NLDC with approval of the Commission and beta shall range between 0 to 1.

Provided that incentive shall be payable only if Beta value is higher than 0.30.

CC_y= Capacity Charges for the Year.

(5) The energy charge shall be payable by every beneficiary for the total energy scheduled to be supplied to the beneficiary, excluding free energy, if any, during the calendar month, on the ex-bus basis, at the computed energy charge rate. The total energy charge payable to the generating company for a month shall be:

Energy Charges = (Energy charge rate in Rs. / kWh) x {Scheduled energy (ex-bus) for the month in kWh} x (100 – FEHS) / 100

(6) Energy charge rate (ECR) in Rupees per kWh on ex-power plant basis, for a hydro generating station, shall be determined up to three decimal places based on the following formula, subject to the provisions of clause (8) of this Regulation:

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 MWh, subject to the provision in clause (7) below.

FEHS = Free energy for home State, in per cent, as mentioned in EXPLANATION-III under Regulation 76 of these regulations.

(7) 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.

(8) 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 tariff period 2019-24, 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.

(9) In case the energy charge rate (ECR) for a hydro generating station, computed as per clause (5) of this Regulation 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.

(10) In addition to the above, an incentive shall be payable to a ROR 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).

66. **Computation and Payment of Capacity Charge and Energy Charge for Pumped Storage Hydro Generating Stations:**

(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;

Provided that during the period between the date of commercial operation of the first unit of the generating station and the date of commercial operation of the generating station, the annual fixed cost shall be worked out based on the latest estimate of the completion cost for the generating station, for the purpose of determining the capacity charge payment during such period.

(2) The capacity charge payable to a pumped storage hydro generating station for a calendar month shall be:

(AFC x NDM / NDY) (In Rupees), if actual Generation during the month is ≧ 75 % of the Pumping Energy consumed by the station during the month and {(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 Rupees)}, 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 Rupees

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.

(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.

(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.

(5) The generating company 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 x (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 Grid Code.

(6) The concerned Load Despatch Centre shall finalise the schedules for the 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.

67. **Computation and Payment of Transmission Charge for Inter-State Transmission System and Communication System:**

(1) The fixed cost of the transmission system or communication system forming part of the transmission system shall be computed on an annual basis, in accordance with norms contained in these regulations, aggregated as appropriate, and recovered on a monthly basis as transmission charge from the users, who shall share these charges in the manner specified in clause (2) of this Regulation.

(2) The Transmission charge (inclusive of incentive) payable for a calendar month for the transmission system or part shall be computed for each region separately for the AC and DC system as under:

For AC system:

a) For $TAFM_n \leqq 98.00\%$

AFC x (NDM_n/NDY) x ($TAFM_n$/98.00%)

b) For $TAFM_n$: $98.00\% < TAFM_n < 98.50\%$

AFC x (NDM_n/NDY) x (1)

c) For $TAFM_n$: $98.50\% < TAFM_n \leqq 99.75\%$

AFC x (NDM_n/NDY) x (TAFM/98.50%)

d) For $TAFM_n > 99.75\%$

AFC x (NDM_n/NDY) x (99.75%/98.50%)

Where,

AFC = Annual Fixed Cost specified for the year in Rupees

NDM_n = Number of days in nth month

NDY = Number of days in the year

$TAFM_n$ = Transmission System availability factor for the nth month, in percent computed in accordance with Appendix IV.

For HVDC bi-pole links and HVDC back-to-back Stations:

TC_1= AFC x (NDM_1 / NDY) x ($TAFM_1$/NATAF)

TC_2 = AFC x (NDM_2 / NDY) x ($TAFM_2$/NATAF) – TC_1

TC_3 = AFC x (NDM_3 / NDY) x ($TAFM_3$/NATAF) - (TC_1+TC_2)

TC_4 = AFC x (NDM_4 / NDY) x ($TAFM_4$/NATAF) - (TC_1+TC_2+TC_3)

…..

TC_{11} = AFC x (NDM_{11}/NDY) x ($TAFM_{11}$/NATAF) - (TC_1+TC_2+....+TC_{10})

TC_{12}= AFC x (TAFY/NATAF) - (TC_1+TC_2+....+TC_{11});

If,

(i) TAFM: 95.00%$<$ TAFM $<$ 97.50%, then TAFM=NATAF;

(ii) TAFM: 97.50%$\leqq$ TAFM $\leqq$ 99.75%, then NATAF=97.50%; and

(iii) For TAFM $\geqq$ 99.75%, then TAFM=99.75% and NATAF= 97.50%.

Where,

TCn = Transmission charges inclusive of incentive up to the nth month

AFC = Annual fixed cost specified for the year in rupees

NATAF = Normative Annual Transmission Availability Factor in percentage

NDM_n = No of days up to the end of the nth month of the financial year

NDY = No. of days in the year

$TAFM_{n.}$ = Transmission availability factor up to the end of the nth month of the year in percentage computed in accordance with Appendix -IV

TAFY = Transmission availability factor in per cent for the year.

(3) The transmission charges shall be calculated separately for part of the transmission system having different NATAF and aggregated thereafter, according to their sharing by the long term customers or DICs or GNA grantee. The charges of the communication system shall be a part of the transmission charges and shall be shared by the long term customers.

68. **Deviation Charges:** (1) Variations between actual net injection and scheduled net injection for the generating stations, and variations between actual net drawl and scheduled net drawl for the beneficiaries shall be treated as their respective deviations and charges for such deviations shall be governed by the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related matters) Regulations, 2022.

(2) The actual net deviation of every generating station and Beneficiary shall be metered on its periphery through special energy meters (SEMs) installed by the Central Transmission Utility (CTU), and computed in MWh for each 15-minute time block by the concerned Regional Load Despatch Centre.

CHAPTER - 12

NORMS OF OPERATION

69. **Recovery of Tariff and Incentive:** (1) Recovery of capacity charge, energy charge, supplementary capacity charge, supplementary energy charge, transmission charge and incentive by the generating company and the transmission licensee shall be based on the achievement of the operational norms specified in the Regulation 70 to Regulation 72 of these regulations.

(2) The Commission may on its own revise the norms of Station Heat Rate specified in Regulation 70(C) of these regulations in respect of any of the generating stations for which relaxed norms have been specified.

Norms of operation for thermal generating station

70. The norms of operation as given hereunder shall apply to thermal generating stations:

(A) **Normative Annual Plant Availability Factor (NAPAF)**

(a) 85% for all thermal generating stations, except those covered under clauses (b), (c), (d) and (e);

(b) 83% for coal and lignite based generating stations completing 30 years from COD as on 31.03.2024;

(c) For the following Gas based Thermal generating stations of NEEPCO:

Assam GPS	70%
Agartala GPS	85%
Tripura GPS	85%

(d) Lignite fired generating stations using Circulatory Fluidized Bed Combustion (CFBC)

Technology and generating stations based on coal rejects:

1. First Three years from the date of commercial operation – 68.50%

2. After completion of three years of the date of commercial operation - 75%

(e) For following lignite fired thermal generating stations of NLC India Ltd.

1. TPS-II State-I and Stage-II : 80%

2. Barsingsar (CFBC) : 75%

3. TPS-II Expansion (CFBC) : 70%

4. TPS-1 Expansion : 85%

5. New Neyveli TPS : 80%

(B) **Normative Annual Plant Load Factor (NAPLF) for Incentive:**

(a) 85% for all thermal generating stations, except for those covered under clause (b) below

(b) 83% for coal and lignite based generating stations completing 30 years from COD as on 31.03.2024

(C) **Gross Station Heat Rate:**

(a) **Existing Thermal Generating Stations achieving COD before 1.4.2009**

(i) For Coal-based Thermal generating stations other than those covered under clause (ii) below:

200-300 MW Sets	**500 MW Sets (Sub-critical)**
2,415kCal/kWh	2,375kCal/kWh

Note 1

In respect of 500 MW and above units where the boiler feed pumps are electrically operated, the gross station heat rate shall be 40 kCal/kWh lower than the gross station heat rate specified above.

Note 2

For the generating stations having combination of 200/210/250 MW and above sets and 500 MW and above sets, the normative gross station heat rate shall be the weighted average gross station heat rate of the combinations.

Note 3

The normative gross station heat rate above is exclusive of the compensation specified as per the Grid Code. The generating company shall, based on the unit loading factor, consider the compensation in addition to the normative gross heat rate above.

Note 4

The gross station heat rate for the unit capacity of less than 200 MW sets, shall be dealt with on a case-to-case basis.

(ii) For the following Thermal generating stations of NTPC Ltd:

Tanda TPS	2,750 kCal/kWh

(iii) Lignite-fired Thermal Generating Stations:

TPS-II (Stg I & II) : 2,880 kCal/kWh

TPS-I (Expansion) : 2,710 kCal/kWh

(iv) Open Cycle Gas Turbine/Combined Cycle Generating Stations: For the following gas-based thermal generating stations:

Name of generating station	**Combined cycle (kCal/kWh)**	**Open Cycle (kCal/kWh)**
Gandhar GPS	2,040	2,960
Kawas GPS	2,050	3,010
Anta GPS	2,075	3,010
Dadri GPS	2,000	3,010
Auraiya GPS	2,100	3,045
Faridabad GPS	1,975	2,900
Kayamkulam GPS	2,000	2,900
Assam GPS	2,600	3,578
Agartala GPS	2,600	3,578
Ratnagiri	1,820	2,641

(b) **Thermal Generating Stations achieving COD on or after 1.4.2009:**

(i) For Coal-based and lignite-fired 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
SHT/RHT (^{0}C)	535/535	537/537	537/565
Type of BFP	Electrical Driven	Turbine Driven	Turbine Driven
Max Turbine Heat Rate (kCal/kWh)	1955	1950	1935
Min. Boiler Efficiency			
Sub-Bituminous Indian Coal (%)	86	86	86
Bituminous Imported Coal (%)	89	89	89

Pressure Rating (Kg/cm2)	247	247	260	270	270
SHT/RHT (^{0}C)	537/565	565/593	593/593	593/593	600/600
Type of BFP	Turbine Driven	Turbine Driven	Turbine Driven	Turbine Driven	Turbine Driven
Max Turbine Heat Rate (kCal/kWh)	1900	1850	1814	1810	1790
Min. Boiler Efficiency (%)					
Sub-Bituminous Indian Coal (%)	86.00	86.00	86.00	86.50	86.50
Bituminous Imported Coal (%)	89.00	89.00	89.50	89.50	89.50

** For Lignite fired thermal generating station, the minimum boiler efficiency shall be 76% (for pulverised) and 80% (for fluidised bed) based boilers.*

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 Sub-bituminous 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 1.4.2024, the heat rate norms for those generating units as well as generating units declared under commercial operation on or after 1.4.2024 shall be lowest of the heat rate norms considered by the Commission during tariff period 2019-24 or those arrived at by above methodology or the norms as per the sub-clause (C)(a)(i) of this Regulation:

Provided also that for Generating stations based on coal rejects, the Commission shall approve the Station Heat Rate on a case-to-case basis.

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.

(ii) For the following Thermal generating stations of NTPC Ltd:

Kanti TPS	2,500 kCal/kWh

(iii) For the following lignite generating stations of NLC India Ltd:

Barsingsar (2X125 MW)	2,525 kCal/kWh

(c) **For Gas-based/ Liquid based Thermal Generating Unit(s)/ Block(s) having COD on or after 1.4.2009:**

For Natural Gas and RLNG= 1.050 X Design Heat Rate of the unit/block (kCal/kWh)

For Liquid Fuel=1.071 X Design Heat Rate of the unit/block for Liquid Fuel (kCal/kWh)

Where the Design Heat Rate of a unit shall mean the guaranteed heat rate for a unit at 100% MCR and at site ambient conditions, and the Design Heat Rate of a block shall mean the guaranteed heat rate for a block at 100% MCR, site ambient conditions, zero per cent make up, design cooling water temperature/back pressure.

(d) The Gross Station Heat Rate norms as specified in sub-clauses (a) and (b) of this clause, in respect of the coal and lignite based generating stations or units thereof (except for the generating stations or units thereof for which relaxed norms have been specified) and commissioned till 31.3.2024 (before 2009 and after 2009) shall remain applicable for such generating stations or units thereof for the remaining operational life of the respective generating stations or units thereof.

(D) **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

(c) For Lignite-fired generating stations (Pulverised and CFBC): 1.0 ml/kWh

(d) For Coal-based generating stations of DVC:

Mejia TPS (Unit 1 to 3)	1.00 ml/kWh
Mejia TPS (Unit 4)	1.00 ml/kWh

(e) For Generating Stations based on Coal Rejects: 2.0 ml/kWh

(E) **Auxiliary Energy Consumption:**

(a) For Coal-based generating stations except at (b) below:

S. No.	**Generating Station**	**With Natural Draft cooling tower or without cooling tower**
(i)	200-300 MW series	8.50%
(ii)	300/ 330/ 350/ 500 MW and above	
	Steam driven boiler feed pumps	5.25%
	Electrically driven boiler feed pumps	8.00%
(iii)	600 MW and above	
	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 0.5% and 0.8%, respectively:

Provided further that Additional Auxiliary Energy Consumption as follows shall be allowed for plants with Dry Cooling Systems:

Type of Dry Cooling System	**(% of gross 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) For other Coal-based generating stations:

(i)	Tanda Thermal Power Station	12.00%
(ii)	Chandrapur TPS (2x250 MW) (DVC)	9.50%

(c) For Gas Turbine /Combined Cycle generating stations:

(i) Combined Cycle : 2.75%

(ii) Open Cycle : 1.00%

Provided that where the gas based generating station is using electric motor driven Gas Booster Compressor, the Auxiliary Energy Consumption in case of Combined Cycle mode shall be 3.30% (including the impact of air-cooled condensers for Steam Turbine Generators):

Provided further that an additional Auxiliary Energy Consumption of 0.35% shall be allowed for Combined Cycle Generating Stations having direct cooling air cooled condensers with mechanical draft fans.

(iii) Tripura CCPP : 3.50%

(iv) OTPC Palatana CCPP : 3.50%

(d) For Lignite-fired thermal generating stations:

(i) For all generating stations with 200 MW sets and above:

The auxiliary energy consumption norms shall be 0.5 percentage points more than the auxiliary energy consumption norms of coal-based generating stations at (E) (a) above.

Provided that for the lignite fired stations using CFBC technology, the auxiliary energy consumption norms shall be 1.5 percentage points more than the auxiliary energy consumption norms of coal-based generating stations at (E) (a) above.

(ii) For Barsingsar Generating station of NEC using CFBC technology: 12.50%

(iii) For TPS-I (Expansion) and TPS-II Stage-I&II of NLC India Ltd.:

TPS-II Stage-I and Stage-II	10.00%
TPS-II (Expansion)	12.50%

(e) For Generating Stations based on coal rejects: 10%

(f) Norms of Auxiliary energy consumption for the emission control system (AUX_{en}) of thermal generating stations:

Name of Technology	**AUX_{en} (as % of grossgeneration)**
(1) For reduction of emission of Sulphur dioxide:	
a) Wet Limestone based FGD system (without Gas to Gas heater)	1.0%
b) Lime Spray Dryer or Semi dry FGD System	1.0%
c) Dry Sorbent Injection System (using Sodium bicarbonate)	NIL
d) For CFBC Power plant (furnace injection)	NIL
e) Sea water based FGD system (without Gas to Gas heater)	1.00%
(2) For reduction of emission of oxide of nitrogen:	
a) Selective Non-Catalytic Reduction system	NIL
b) Selective Catalytic Reduction system	0.2%

Provided that where the technology is installed with a "Gas to Gas" heater, AUX_{en} specified above shall be increased by 0.20% of gross generation.

(F) **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 following the formula:

[K x Normative heat rate (kcal/kWh) x Sulphur content of coal (%)/CVPF 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 60 of these regulations;

(b) Weighted Average Gross calorific value of lignite as received, in kCal per kg, as applicable for lignite based thermal generating stations:

Provided that the value of K shall be equivalent to (35.2 x Design SO_2 Removal Efficiency/96%) to comply with the SO_2 emission norm of 100/200 mg/Nm^3 or (26.8 x Design SO_2 Removal Efficiency/73%) for units to comply with the SO_2 emission norm of 600 mg/Nm^3;

Provided further that the limestone purity shall not be less than 85%.

(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 x90/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 CFBC Technology (furnace injection) based generating station: The specific limestone consumption for CFBC based generating station (furnace injection) shall be computed with the following formula:

[62.9 x S x SHR/ CVPF] x[85/LP]

Where

S = Sulphur content in percentage,

LP = Limestone Purity in percentage,

SHR = Gross station heat rate, in kCal per kWh,

CVPF = (a) Weighted Average Gross calorific value of lignite as received, in kCal per kg as applicable for lignite based thermal generating stations;

(e) 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.

71. **Norms of Operation for Hydro Generating Stations: The norms of operation as given hereunder shall apply to hydro generating stations:**

(A) Normative Annual Plant Availability Factor (NAPAF): (1) The following normative annual plant availability factor (NAPAF) shall apply to hydro generating station:

(a) Storage and Pondage type plants with head variation between Full Reservoir Level (FRL) and Minimum Draw Down Level (MDDL) of up to 8%, and where plant availability is not affected by silt: 90%;

(b) In the case of storage and pondage type plants with head variation between full reservoir level and minimum draw down level is more than 8% and when plant availability is not affected by silt, the month-wise peaking capability as provided by the project authorities in the DPR (approved by CEA or the State Government) shall form the basis of fixation of NAPAF;

(c) Pondage type plants where plant availability is significantly affected by silt: 85%.

Run-of-river generating stations: NAPAF to be determined plant-wise, based on 10-day design energy data, moderated by past experience where available/relevant.

(2) A further allowance may be made by the Commission in NAPAF determination under special circumstances, e.g. abnormal silt problem or other operating conditions, and known plant limitations.

(3) A further allowance of 5% may be allowed for difficulties in North East Region.

(4) Based on the above, the Normative annual plant availability factor (NAPAF) of the hydro generating stations already in operation shall be as follows: -

Station	Type of Plant	Plant Capacity No. of Units x MW	NAPAF (%)
THDC			
THPS	Storage	4x250	77
KHEP	Storage	4x100	66
NHPC			
Station	**Type of Plant**	**Plant Capacity No. of Units x MW**	**NAPAF (%)**
Bairasul	Pondage	3x60	85
Loktak	Pondage	3x35	88
Salal	ROR	6x115	70
Tanakpur	ROR	3x31.4	70
Chamera-I	Pondage	3x180	90

Station	Type of Plant	Plant Capacity No. of Units x MW	NAPAF (%)
Uri I	ROR	4x120	80
Rangit	Pondage	3x20	90
Chamera-II	Pondage	3x100	87
Dhauliganga	Pondage	4x70	85
Dulhasti	Pondage	3x130	90
Teesta-V	Pondage	3x170	87
Sewa-II	Pondage	3x40	86
TLDP III	Pondage	4x33	80
Chamera III	Pondage	3x77	87
Chutak	ROR	4x11	48
Nimmo Bazgo	Pondage	3x15	70
Uri II	ROR	4x60	80
Parbati III	Pondage	4x130	45
TLDP IV	ROR with Pondage	4x40	90
Kishanganga	ROR with Pondage	3x110	83
Teesta III	Pondage	6x200	85
NHDC			
Indira Sagar	Storage	8x125	87
Omkareshwar	Pondage	8x65	90
NEEPCO			
Kopili I	Storage	4x50	69
Khandong	Storage	2x25	67
Kopili II	Storage	1x25	69
Doyang	Storage	3x25	65
Ranganadi	Pondage	3x135 .	85
Tuirial	Storage	2x30	75
NTPC			
Koldam	Storage	4x200	90
SJVNL			
Nathpa Jhakri	Pondage	6x250	87
Rampur	Pondage	6x68.67	83
DVC			
Panchet	Storage	2x40	80
Tilaya	Storage	2x2	80
Maithon	Storage	3x20	80
Karcham Wangtoo	ROR with	4x261.25	90

Station	Type of Plant	Plant Capacity No. of Units x MW	NAPAF (%)
	Pondage		

(B) In the case of pumped storage hydro generating stations, the quantum of electricity required for pumping water from the down-stream reservoir to the up-stream reservoir shall be arranged by the beneficiaries duly taking into account the transmission and distribution losses up to the bus bar of the generating station. In return, beneficiaries shall be entitled to an equivalent energy of 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir from the generating station during peak hours, and the generating station shall be under obligation to supply such quantum of electricity during peak hours:

Provided that in the event of the beneficiaries failing to supply the desired level of energy during off-peak hours, there will be a pro-rata reduction in their energy entitlement from the station during peak hours:

Provided further that the beneficiaries may assign or surrender their share of capacity in the generating station, in part or in full, or the capacity may be reallocated by the Central Government, and in that event, the owner or assignee of the capacity share shall be responsible for arranging the equivalent energy to the generating station in off-peak hours, and be entitled to corresponding energy during peak hours in the same way as the original beneficiary was entitled.

(C) Auxiliary Energy Consumption (AEC):

Type of Station	AEC	
	Installed Capacity above 200 MW	Installed Capacity upto 200 MW
Surface		
Rotating Excitation	0.7%	0.7%
Static	1.0%	1.2%
Underground		

Type of Station	AEC	
	Installed Capacity above 200 MW	**Installed Capacity upto 200 MW**
Rotating Excitation	0.9%	0.9%
Static	1.2%	1.3%

* AEC for Tuirial HPS = 4%

Norms of operation for transmission system

72. **Normative Annual Transmission System Availability Factor (NATAF):**

(a) For recovery of Annual Fixed Cost, NATAF shall be as under:

(1) AC system: 98.00%;

(2) HVDC bi-pole links 95.00% 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 the first twelve months from the date of commercial operation.

(b) For Incentive, NATAF shall be as under:

(1) AC system: 98.50%;

(2) HVDC bi-pole links and HVDC back-to-back Stations: 97.50%:

Provided that no Incentive shall be payable for availability beyond 99.75%:

Provided further that for AC and HVDC system, actual outage hours shall be considered for computation of availability up to 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 an outage of a transmission element affecting evacuation of power from a generating station, outage hours shall be multiplied by a factor of 2.

73. **Auxiliary Energy Consumption in the Sub-station**

(1) AC System: The charges for auxiliary energy consumption in the AC sub-station for the purpose of air-conditioning, lighting and consumption in other equipment shall be borne by the transmission licensee and included in the normative operation and maintenance expenses.

(2) HVDC sub-station: For auxiliary energy consumption in HVDC sub-stations, the Central Government may allocate an appropriate share from one or more ISGS. The charges for such power shall be borne by the transmission licensee from the normative operation and maintenance expenses.

CHAPTER - 13

SCHEDULING, ACCOUNTING AND BILLING

74. **Scheduling:** The methodology for scheduling and dispatch for the generating station shall be as specified in the Grid Code.

75. **Metering and Accounting:** For metering and accounting, the provisions of the Grid Code shall be applicable.

76. **Billing and Payment of charges:** (1) Bills shall be raised for capacity charge and energy charge by the generating company and for transmission charge by the transmission licensee on a monthly basis in accordance with these regulations, and payments shall be made by the beneficiaries or the long term customers directly to the generating company or the transmission licensee, as the case may be:

EXPLANATION-I: The physical copy of the Bill in Original at the office of the Authorised Person of the beneficiary or long term customer, as the case may be, or the scanned copy of the Original Bill through the official email ID of the Authorised Signatory of the Generating Company or the Transmission Licensee, as the case may be, shall be recognized as a valid mode of presentation of Bill:

EXPLANATION-II: Authorized Signatory or Signatories (official designation only) shall be notified in advance by the Managing Director or Chief Executive Officer of the Company, and any change in the list of Authorised Signatories for the purpose shall be communicated in the same manner.

(2) Payment of the capacity charge for a thermal generating station shall be shared by the beneficiaries of the generating station as per their percentage shares for the month (inclusive of any

allocation out of the unallocated capacity) in the installed capacity of the generating station. Payment of capacity charge and energy charge for a hydro generating station shall be shared by the beneficiaries of the generating station in proportion to their shares (inclusive of any allocation out of the unallocated capacity) in the saleable capacity (to be determined after deducting the capacity corresponding to free energy to home State as per Note 3 herein.

EXPLANATION-I: Shares or allocations of each beneficiary in the total capacity of Central sector generating stations shall be as determined by the Central Government, inclusive of any allocation made out of the unallocated capacity. The shares shall be applied in percentages of installed capacity and shall normally remain constant for a month. Based on the decision of the Central Government, the changes in allocation shall be communicated by the Member-Secretary, Regional Power Committee in advance, at least three days prior to the beginning of a calendar month, except in case of an emergency call for an urgent change in allocations out of unallocated capacity. The total capacity share of a beneficiary would be the sum of its capacity share plus allocation out of the unallocated portion.

EXPLANATION-II: The beneficiaries may propose surrendering part of their allocated firm share to other States within or outside the region. In such cases, depending upon the technical feasibility of power transfer and specific agreements reached by the generating company with other States within or outside the region for such transfers, the shares of the beneficiaries may be re-allocated by the Central Government for a specific period (in complete months) from the beginning of a calendar month. When such re-allocations are made, the beneficiaries who surrender the share shall not be liable to pay capacity charges for the surrendered share. The capacity charges for the capacity surrendered and reallocated as above shall be paid by the State(s) to whom the surrendered capacity is allocated. Except for the period of reallocation of capacity as above, the beneficiaries of the generating station shall continue to pay the full capacity charges as per allocated capacity shares. Any such reallocation and its reversion shall be communicated to all concerned by the Member Secretary, Regional Power Committee in advance, at least three days prior to such reallocation or reversion taking effect.

EXPLANATION-III: FEHS = Free energy for home State, in per cent and shall be taken as 13% or actual, whichever is less.

Provided that in cases where the site of a hydro project is awarded to a developer, by the State Government by following a two-stage transparent process of bidding, the 'free energy' shall be taken as 13%, in addition to an energy corresponding to 100 units of electricity to be provided free of cost every month to every project affected family for a period of 10 years from the date of commercial operation of the generating station:

Provided further that the generating company shall submit a detailed quantification of energy corresponding to 100 units of electricity to be provided free of cost every month to every month to every project-affected family for a period of 10 years from the date of commercial operation.

77. **Recovery of Statutory Charges:** The generating company shall recover the statutory charges imposed by the State and Central Government, such as electricity duty and water cess, by considering normative parameters specified in these regulations. In case the electricity duty is applied to the auxiliary energy consumption, such amount of electricity duty shall apply to the normative auxiliary energy consumption of the generating station (excluding colony consumption) and apportioned to each of the beneficiaries in proportion to their scheduled dispatch during the month.

78. **Sharing of Transmission Charges:** (1) The sharing of transmission charges shall be governed by the Sharing Regulations.

(2) The charges determined under these regulations in relation to the communication system forming part of the transmission system shall be shared by the beneficiaries or long term customers in accordance with the Sharing Regulations:

Provided that charges determined under these regulations in relation to communication systems other than that of the central portion shall be shared by the beneficiaries in proportion to the capital cost belonging to respective beneficiaries.

79. **Rebate:** (1) For payment of bills of the generating company and the transmission licensee through letter of credit on presentation or through National Electronic Fund Transfer (NEFT) or Real Time Gross Settlement (RTGS) payment mode within a period of 5 days of presentation of bills by the generating company or the transmission licensee, a rebate of 1.50% shall be allowed.

Provided that in case a different Rebate mechanism is provided in the PPA, the same shall be governed by the provisions of the PPA.

Explanation: In case of computation of '5 days', the number of days shall be counted consecutively without considering any holiday. However, in case the last day or day is an official holiday, the 5th day for the purpose of Rebate shall be construed as the immediate succeeding working day (as per the official State Government's calendar, where the Office of the Authorised Signatory or Representative of the Beneficiary, for the purpose of receipt or acknowledgement of Bill is situated).

(2) Where payments are made on any day after 5 days and within a period of 30 days of presentation of bills by the generating company or the transmission licensee, a rebate of 1% shall be allowed.

80. **Late payment surcharge**: (1) In case the payment of any bill for charges payable under these regulations is delayed by a beneficiary or long term customer as the case may be, beyond a period

of 45 days from the date of presentation of bills, a late payment surcharge as specified in the Ministry of Power – Electricity (Late Payment Surcharge and Related Matters) Rules, 2022 as amended from time to time shall be levied by the generating company or the transmission licensee, as the case may be.

Provided that in case a different LPS mechanism is provided in the PPA, the same shall be governed by the provisions of the PPA.

(2) Unless otherwise agreed by the parties, the charges payable by a beneficiary or long term customer shall be first adjusted towards a late payment surcharge on the outstanding charges and, thereafter, towards monthly charges billed by the generating company or the transmission licensee, as the case may be, starting from the longest overdue bill.

CHAPTER – 14

SHARING OF BENEFITS

81. **Sharing of gains due to variation in norms:** (1) The generating company or the transmission licensee shall work out gains based on the actual performance of applicable Controllable parameters as under:

i) Station Heat Rate;

ii) Secondary Fuel Oil Consumption; and

iii) Auxiliary Energy Consumption.

(2) The financial gains by the generating company or the transmission licensee, as the case may be, on account of controllable parameters shall be shared between the generating company or transmission licensee and the beneficiaries or long term customers, as the case may be on an annual basis. The financial gains computed as per the following formulae in the case of generating stations other than hydro generating stations on account of operational parameters as shown in Clause (1) of this Regulation shall be shared in the ratio of 1:1 between the generating stations and beneficiaries.

Net Gain = (ECR_N- ECR_A) X Scheduled Generation

Where,

ECR_N = Normative Energy Charge Rate computed on the basis of norms specified for Station Heat Rate, Auxiliary Energy Consumption and Secondary Fuel Oil consumption.

ECR_A = Actual Energy Charge Rate computed on the basis of actual Station Heat Rate, actual Auxiliary Energy Consumption and actual Secondary Fuel Oil Consumption.

Provided that in the case of hydro generating stations, the net gain on account of Actual

Auxiliary Energy Consumption being less than the Normative Auxiliary Energy Consumption shall be computed as per the following formulae provided the saleable scheduled generation is more than the saleable design energy and shall be shared in the ratio of 1:1 between generating station and beneficiaries:

(i) When saleable scheduled generation is more than saleable design energy on the basis of normative auxiliary energy consumption and less than or equal to saleable design energy on the basis of actual auxiliary energy consumption:

Net gain (Million Rupees) = [(Saleable Scheduled generation in

MUs) - (Saleable Design energy on the basis of normative auxiliary energy consumption in MUs)] x [1.30 or ECR, whichever is lower]

(ii) When saleable scheduled generation is more than saleable design energy on the basis of actual auxiliary energy consumption:

Net gain (Million Rupees) = {Saleable Scheduled generation in MUs- [(Saleable Scheduled Generation in MUs x (100 - normative AEC in %)/(100 actual AEC in %)]}x [1.30 or ECR, whichever is lower]

82. **Sharing of savings in interest due to re-financing or restructuring of loan :(**1) If re-financing or restructuring of loan by the generating company or the transmission licensee, as the case may be, results in net savings on interest after accounting for cost associated with such refinancing or restructuring, the same shall be shared between the generating company or the transmission licensee and the beneficiaries, as the case may be, in the ratio of 1:1.

(2) In case of dispute, any of the parties may make an application in accordance with the Central Electricity Regulatory Commission (Conduct of Business) Regulations, 2023 for settlement of the

dispute:

Provided that the beneficiaries or the long term customers shall not withhold any payment on account of the interest claimed by the generating company or the transmission licensee during the pendency of any dispute arising out of re-financing of the loan.

83. Sharing of net gains referred to in Regulation 48(3)(e) and Regulation 49(1)(l) of Grid Code, unless specifically provided in the rules or the guidelines issued by the Central Government, shall be in the ratio of 1:1.

84. **Sharing of Non-Tariff Income:** The non-tariff net income in case of generating station and transmission system from rent of land or buildings, eco-tourism, sale of scrap, and advertisements shall be shared between the generating company or the transmission licensee and the beneficiaries or the long term customers, as the case may be, in the ratio of 1:1.

85. **Sharing of Clean Development Mechanism Benefits:** The proceeds of carbon credit from approved emission reduction projects under the Clean Development Mechanism shall be shared in the following manner:

(a) 100% of the gross proceeds on account of CDM to be retained by the project developer in the first year after the date of commercial operation of the generating station or the transmission system, as the case may be;

(b) In the second year, the share of the beneficiaries shall be 10% which shall be progressively increased by 10% every year till it reaches 50%, where after the proceeds shall be shared in equal proportion, by the generating company or the transmission licensee, as the case may be, and the beneficiaries.

86. **Sharing of income from other business of transmission licensee:** The income from other

business of the transmission licensee shall be shared with the long term customer in the manner as specified in the Central Electricity Regulatory Commission (Sharing of revenue derived from utilization of transmission assets for other business) Regulations, 2020.

CHAPTER 15

MISCELLANEOUS PROVISIONS

87. **Operational Norms to be ceiling norms:** Operational norms specified in these regulations are the ceiling norms and shall not preclude the generating company or the transmission licensee, as the case may be, and the beneficiaries and the long-term customers from agreeing to the improved norms and in case the improved norms are agreed to, such improved norms shall be applicable for determination of tariff.

88. **Deviation from ceiling tariff:** (1) The tariff determined in these regulations shall be a ceiling tariff. The generating company or the transmission licensee and the beneficiaries or the long-term customer, as the case may be, may mutually agree to charge a lower tariff.

(2) The generating company or the 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.

(3) If the generating company or the transmission licensee opts to charge a lower tariff for a period not exceeding the validity of these regulations on account of lower depreciation based on the requirement of repayment in such case, the unrecovered depreciation on account of reduction of depreciation by the generating company or the transmission licensee during useful life shall be allowed to be recovered after the useful life in these regulations.

(4) The deviation from the ceiling tariff specified by the Commission, shall come into effect from the date agreed to by the generating company or the transmission licensee and the beneficiaries or the long-term customer, as the case may be.

(5) The generating company and the beneficiaries of a generating station or the transmission licensee and the long term customer of the transmission system shall be required to approach the Commission for charging a lower tariff in accordance with clauses (1) to (3) above. The details of the accounts and the tariff actually charged under clauses (1) to (3) shall be submitted at the time of true up.

(6) Where a generating company and its beneficiaries or a transmission licensee and its long-term customers have mutually agreed to charge a lower tariff in respect of a particular generating station or transmission system in terms of Clauses (1) to (3) of this Regulation, the said agreed tariff shall not be revised upwards at the time of truing up based on the capital cost and additional capital expenditures in accordance with these regulations:

Provided that where the trued up tariff is lower than the agreed tariff, the generating company or the transmission licensee shall charge such trued-up tariff only:

Provided further that the difference between the agreed tariff and the trued-up tariff shall be settled between the parties in accordance with Regulations 10(7) and 10(8) of these regulations.

89. **Deferred Tax liability with respect to the previous tariff period:** Deferred tax liabilities for the period up to 31st March 2009, whenever they materialise, shall be recoverable directly by the generating companies or transmission licensees from the then beneficiaries or long term customers, as the case may be. Deferred tax liabilities for the period arising from 1.4.2009 to 31.3.2024, if any, shall not be recoverable from the beneficiaries or the long term customers, as the case may be.

90. **Hedging of Foreign Exchange Rate Variation:** (1) The generating company or the

transmission licensee, as the case may be, may hedge foreign exchange exposure in respect of the interest and repayment of foreign currency loan taken for the generating station or the transmission system, in part or in full at their discretion.

(2) If the petitioner enters into hedging arrangement(s) based on its approved hedging policy, the petitioner shall communicate to the beneficiaries concerned, of entering into such arrangement(s) within thirty days.

(3) Every generating company and transmission licensee shall recover the cost of hedging of foreign exchange rate variation corresponding to the normative foreign debt, in the relevant year on a year-to-year basis as expense in the period in which it arises and extra rupee liability corresponding to such foreign exchange rate variation shall not be allowed against foreign debt.

(4) To the extent the generating company or the transmission licensee is not able to hedge the foreign exchange exposure, the extra rupee liability towards interest payment and loan repayment corresponding to the normative foreign currency loan in the relevant year shall be permissible, provided it is not attributable to the generating company or the transmission licensee or its suppliers or contractors.

91. **Award of Arbitration:** In cases where there is a liability with respect to capital works on account of award of arbitration having principal amount along with interest payment, the principal amount actually paid shall be capitalised.

Provided that any interest amount associated with the arbitration award and actually paid shall be recovered in instalments along with carrying cost at the rate specified under Regulation 10(6) and 10(7) of these Regulations.

Provided further that such number of instalments shall be decided by the Commission on a case-to-case basis depending upon the amount to be reimbursed.

92. **Recovery of the cost of hedging or Foreign Exchange Rate Variation (FERV):**

(1) Every generating company and the transmission licensee shall recover the cost of hedging and foreign exchange rate variation on a year-to-year basis as income or expense in the period in which it arises.

(2) Recovery of the cost of hedging or foreign exchange rate variation shall be made directly by the generating company or the transmission licensee, as the case may be, from the beneficiaries or the long term customers, as the case may be, without making any application before the Commission:

Provided that in case of any objections by the beneficiaries or the long term customers, as the case may be, to the amounts claimed on account of the cost of hedging or foreign exchange rate variation, the generating company or the transmission licensee, as the case may be, may make an appropriate application before the Commission for its decision.

93. **Approval Process of Non-ISTS Lines carrying Inter-State Power:**

Existing intra-state transmission lines other than Natural ISTS lines, as certified by CEA based on the recommendations of the STU and RPC, shall be considered as ISTS systems.

Provided that these transmission lines are being used for evacuation and transfer of inter-state power on a regular basis as identified by CTU in consultation with the concerned RPC and RLDC;

Provided further that such transmission system is under operation and appropriate metering system is in place to record flow of power;

Provided further that a proper mechanism is in place for the maintenance of such a transmission system after its COD;

Provided that such lines have not been developed for the sole purpose of the beneficiary(ies) of a single State.

(1) Existing Intra State lines which were planned as ISTS System shall also be considered as ISTS lines;

Provided that such lines have not been developed for the sole purpose of the beneficiary(ies) of a single State;

Provided further that such transmission system is under operation and appropriate metering system is in place to record flow of power;

Provided further that a proper mechanism is in place for the maintenance of such a transmission system after its COD.

(2) CTU, in consultation with RLDC, shall identify all such non-ISTS lines which are utilized for ISTS power transfer after ascertaining that such nature of flow of power has become permanent.

(3) No New ISTS lines shall henceforth be planned and developed by State Transmission Utility unless agreed by CTU in consultation with RPC and approved by the Ministry of Power.

(4) New transmission lines which have been conceived as ISTS lines at the planning stage shall be considered as part of the ISTS system;

Provided that such lines have not been developed for the sole purpose of the beneficiary(ies) of a single State;

Provided further that such transmission system is under operation and appropriate metering system is in place to record flow of power;

Provided further that a proper mechanism is in place for the maintenance of such a transmission system after its COD.

(5) Tariff of all such ISTS lines shall be approved based on provisions of these Regulations, and the fixed charges of such system shall be allowed based on the availability certified by respective RPCs and shall be allowed to be recovered as per the mechanism specified in CERC (Sharing of Inter-State Transmission Charges and Losses), 2020.

94. **Application fee and publication expenses:** The following fees, charges and expenses shall be reimbursed directly by the beneficiary in the manner specified herein:

(1) The application filing fee and the expenses incurred on publication of notices in the application for approval of tariff, may at the discretion of the Commission, be allowed to be recovered by the generating company or the transmission licensee, as the case may be, directly from the beneficiaries or the long term customers, as the case may be.

(2) The fees and charges shall be reimbursed directly by the beneficiaries in proportion to their allocation in the generating stations or by the long term customers or DICs in proportion to their share in the inter-State transmission systems determined in accordance with the Central Electricity Regulatory Commission (Sharing of inter-State Transmission Charges and Losses) Regulations, 2020, as amended from time to time.

(3) Fees and charges paid by the generating companies and inter-State transmission licensees (including deemed inter-State transmission licensees) under the Central Electricity Regulatory Commission (Fees and Charges of Regional Load Despatch Centre and other related matters) Regulations, 2009, as amended from time to time or any subsequent amendment thereof.

(4) Licence fees paid by the inter-State transmission licensees (including the deemed inter-State transmission licensee) in terms of Central Electricity Regulatory Commission (Payment of Fees) Regulations, 2012.

(5) Licence fees paid by NHPC Ltd to the State Water Resources Development Authority, Jammu, in accordance with the provisions of the Jammu & Kashmir Water Resources (Regulations and Management) Act, 2010.

(6) The Commission may, for the reasons to be recorded in writing and after hearing the affected parties, allow reimbursement of any fee or expenses, as may be considered necessary.

95. **Special Provisions relating to NLC India Limited:** The tariff of the existing generating stations of NLC India Ltd, namely, TPS-II (Stage I & II) and TPS-I (Expansion), whose tariff for the tariff periods 2004-09, 2009-14 and 2014-19 has been determined by following the Net Fixed Assets approach, shall continue to be determined by adopting Net Fixed Assets approach.

96. **Special Provisions relating to Damodar Valley Corporation:** (1) Subject to clause (2), this Regulation shall apply to the determination of tariff of the projects owned by Damodar Valley Corporation (DVC).

(2) The following special provisions shall apply for the determination of tariff of the projects owned by DVC:

(i) Capital Cost: The expenditure allocated to the object 'power', in terms of sections 32 and 33 of the Damodar Valley Corporation Act, 1948, to the extent of its apportionment to generation and inter-state transmission, shall form the basis of capital cost for the purpose of determination of tariff:

Provided that the capital expenditure incurred on head office, regional offices, administrative and technical centres of DVC, after due prudence check, shall also form part of the capital cost.

(ii) Debt Equity Ratio: The debt-equity ratio of all projects of DVC commissioned prior to 01.01.1992 shall be 50:50, and that of the projects commissioned thereafter shall be 70:30.

(iii) Depreciation: The depreciation rate stipulated by the Comptroller and Auditor General of India in terms of section 40 of the Damodar Valley Corporation Act, 1948 shall be applied for the computation of depreciation of projects of DVC.

(iv) Funds under section 40 of the Damodar Valley Corporation Act, 1948 The Fund(s) established in terms of section 40 of the Damodar Valley Corporation Act, 1948 shall be considered as items of expenditure to be recovered through tariff.

(v) Expenses towards subsidiary activities as per Hon'ble Supreme Court Judgement in Civil Appeal No. 4289 of 2008.

97. **Special Provisions relating to BBMB and SSP:** The tariff of the generating station and the transmission system of Bhakra Beas Management Board (BBMB) and Sardar Sarovar Project (SSP) shall be determined after taking into consideration, the provisions of the Punjab Reorganization Act, 1966 and Narmada Water Scheme, 1980 under Section 6-A of the Inter-State Water Disputes Act, 1956, respectively.

98. **Special Provisions Relating to Certain Inter-State Generation Projects:** (1) The tariff of the generating station and the transmission system of the Indira Sagar generation project and such other inter-state generation projects shall be determined on a case-to-case basis.

99. **Special Provisions relating to Central Transmission Utility of India Ltd. (CTUIL):** The fees and charges of CTUIL shall be allowed separately by the Commission through a separate

regulation:

Provided that until such regulation is issued by the Commission, the expenses of CTUIL shall be borne by Power Grid Corporation of India Ltd. (PGCIL) which shall be recovered by PGCIL as additional O&M expenses through a separate petition.

100. **Transmission Majoration Factor:** Transmission Majoration Factor admissible for the transmission projects executed through the JV route in terms of Regulation 410A of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2001 shall be available for a period of 25 years from the date of issue of the transmission licence.

101. **Public Procurement through Competitive Bidding**: The generating company for a specific generating station or for an integrated mine or a transmission licensee shall procure equipment, work and services through a transparent process of competitive bidding.

Provided that under certain exceptional circumstances, equipment, works and services may be procured through other methods, as provided under general financial rules issued by the Government of India and applicable from time to time.

102. **Power to Relax:** 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 by an interested person.

103. **Power to Remove Difficulty:** If any difficulty arises in giving effect to the provisions of these regulations, the Commission may, by order, make such provision not inconsistent with the provisions of the Act or provisions of other regulations specified by the Commission, as may appear to be necessary for removing the difficulty in giving effect to the objectives of these regulations.

104. **Issue of *Suo-Moto* orders and practice directions**: The Commission may, from time to time,

issue orders and practice directions in regard to the effective implementation of these regulations and matters incidental or ancillary thereto as the Commission may consider appropriate.

Sd/-
(Harpreet Singh Pruthi)
Secretary

Appendix I

Depreciation Schedule

Sr. No.	Asset Particulars	Depreciation Rate (Salvage Value=10%) SLM
A	Land under full ownership	0.00%
B	Land under lease	
(a)	for investment in the land	3.34%
(b)	For cost of clearing the site	3.34%
(c)	Land for reservoir in case of hydro generating station	3.34%
C	Assets purchased new	
a.	Plant & Machinery in generating stations	
(i)	Hydro electric	5.28%
(ii)	Steam electric NHRB & waste heat recovery boilers	5.28%
(iii)	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	100.00%
(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%
Sr. No.	Asset Particulars	Depreciation Rate (Salvage Value=10%) SLM
h.	Batteries	9.50%
(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%
(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	9.50%
l.	Air Conditioning Plants	
(i)	Static	5.28%
(ii)	Portable	9.50%
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	9.50%

(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 including software, UNMS, URTDSM, EMS, Cyber Security System, REMC, WAMS, SCADA System	15.00%
q.	Any other assets not covered above	5.28%

Note: Where the life of the particular asset is less than the useful life of the project, the useful life of such particular asset shall be considered as per the provisions of the Companies Act, 2013 and subsequent amendment thereto.

Appendix II

Depreciation Schedule for New Projects

Sr. No.	Asset Particulars	Depreciation Rate (Salvage Value=10%) SLM
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%
I	Land for reservoir in case of hydro generating station	3.34%
C	Assets purchased new	
a.	Plant & Machinery in generating stations	
(i)	Hydro electric	4.22%
(ii)	Steam electric NHRB & waste heat recovery boilers	4.22%
(iii)	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	100.00%
(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%
Sr. No.	Asset Particulars	Depreciation Rate (Salvage Value=10%) SLM
h.	Batteries	9.50%
(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 higher than 13.2 KV but not exceeding 66 KV	4.22%
(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	9.50%
l.	Air Conditioning Plants	
(i)	Static	4.22%
(ii)	Portable	9.50%
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	9.50%

(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 including software UNMS, URTDSM, EMS, Cyber Security System, REMC, WAMS, SCADA system	15.00%
q.	Any other assets not covered above	4.22%

Note: Where the life of the particular asset is less than the useful life of the project, the useful life of such particular asset shall be considered as per the provisions of the Companies Act, 2013 and subsequent amendment thereto

Appendix III

Depreciation Schedule for Integrated Mine

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	Laboratory & workshop equipment	15
17	Mine Development Expenses and Evaluation and Exploration #	20 or life of mine, whichever is lower
18	Evaluation and Exploration#	20 or life of mine, whichever is lower
19	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 n 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.	

Appendix-IV

Procedure for Calculation of Transmission System Availability Factor for a Month

1. Transmission system availability factor for n^{th} calendar month ("TAFPn") shall be calculated by the respective transmission licensee, verified by the concerned Regional Load Dispatch Centre (RLDC) and certified by the Member-Secretary, Regional Power Committee of the region concerned, separately for each AC and HVDC transmission system and grouped according to sharing of transmission charges. In the case of the AC system, transmission System Availability shall be calculated separately for each Regional Transmission System and inter-regional transmission system. In the case of the HVDC system, transmission System Availability shall be calculated on a consolidated basis for all inter-state HVDC systems.

2. Transmission system availability factor for n^{th} calendar month ("TAFPn") shall be calculated by considering the following:

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 transformers together) shall form one element;

iii) **Static VAR Compensator (SVC):** SVC, along with SVC transformer, shall form one element;

iv) **Bus Reactors or Switchable line reactors:** Each Bus Reactors or Switchable line reactors shall be considered as one element;

v) **HVDC Bi-pole links:** Each pole of the HVDC link, along with associated equipment at both ends, shall be considered as one element;

vi) **HVDC back-to-back station**: Each block of the HVDC back-to-back station shall be considered as one element. If the associated AC line (necessary for the transfer of inter-regional power through the HVDC back-to-back station) is not available, the HVDC back-to-back station block shall also be considered unavailable;

vii) **Static Synchronous Compensation ("STATCOM**"): Each STATCOM shall be considered as a separate element.

3. The Availability of the AC and HVDC portion of the Transmission system shall be calculated by considering each category of transmission elements as under:

TAFPn (in %) for AC system:

$$= \frac{(o \text{ X } AVo)+(p \text{ X } AVp) + (q \text{ X } AVq) + (r \text{ X } AVr)+(u \text{ X } AVu)}{(o + p + q + r+u)} \text{x}100$$

Where,

o	=	Total number of AC lines.
AVo	=	Availability of o number of AC lines
p	=	Total number of bus reactors/switchable line reactors
AVp	=	Availability of p number of bus reactors/switchable line reactors
q1	=	Total number of ICTs
AVq	=	Availability of q number of ICTs
r	=	Total number of SVCs
AVr	=	Availability of r number of SVCs
u	=	Total number of STATCOM
AVu	=	Availability of u number of STATCOM

TAFMn (in %) for HVDC System:

$$= \frac{\sum_{x=1}^{s} \text{Cxbp (act) X AVxbp} + \sum_{y=1}^{t} \text{Cy (act)btb X AVybtb}}{\quad} \text{x}100$$

$$\sum_{x=1}^{s} Cxbp + \sum_{y=1}^{t} Cy\,btb$$

Where

Cxbp(act)	=	Total actual operated capacity of x^{th} HVDC pole
Cxbp	=	Total rated capacity of x^{th} HVDC pole
AVxbp	=	Availability of x^{th} HVDC pole
Cybtb(act)	=	Total actual operated capacity of y^{th} HVDC back-to-back station block
Cybtb	=	Total rated capacity of y^{th} HVDC back-to-back station block
AVybtb	=	Availability of y^{th} HVDC back-to-back station block
s	=	Total no of HVDC poles
t	=	Total no of HVDC Back to Back blocks

3. The availability for each category of transmission elements shall be calculated based on the weightage factor, total hours under consideration and non-available hours for each element of that category. The formulae for calculation of the Availability of each category of the transmission elements are as per **Appendix-V**. The weightage factor for each category of transmission elements shall be considered asunder:

(a) For each circuit of the AC line – The number of sub-conductors in the line multiplied by ckt-km;

(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 stations connecting two Regional grids- Rated MW capacity of each block; and

(g) For STATCOM – Total rated MVAR Capacity.

4. The transmission elements under outage due to the following reasons shall be deemed to be available:

i. Shut down availed for maintenance of another transmission scheme or construction of new element or renovation/upgradation/additional capitalization in an existing system approved by the Commission. If the other transmission scheme belongs to the transmission licensee, the Member Secretary, RPC may restrict the deemed availability period to that considered reasonable by him for the work involved. In case of a dispute regarding deemed availability, the matter may be referred to the Chairperson, CEA, within 30 days.

ii. Switching off of a transmission line to restrict over-voltage and manual tripping of switched reactors as per the directions of the concerned RLDC.

iii. Shut down of a transmission line due to the Project(s) of NHAI, Railways and Border Road Organization, including for shifting or modification of such transmission line or any other infrastructure project approved by Ministry of Power. Member Secretary, RPC may restrict the deemed availability period to that considered reasonable by him for the work involved; Provided that apart from the deemed availability, any other costs involved in the process of such shutdown of transmission line shall not be borne by the DICs.

Provided that such deemed availability shall be considered only for the period for which DICs are not affected by the shutdown of such transmission line.

5. For the following contingencies, the outage period of transmission elements, as certified by the Member Secretary, RPC, shall be excluded from the total time of the element under the period of consideration for the following contingencies:

i) Outage of elements due to force majeure events beyond the control of the transmission licensee. However, whether the same outage is due to force majeure (not design failure) will be verified by the Member Secretary, RPC. A reasonable restoration time for the element shall be considered by the Member Secretary, RPC, 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. Member Secretary, RPC may consult the transmission licensee or any expert for estimation of reasonable restoration time. 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 a substation or bays owned by another agency causing an 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;

iii) The outage period which can be excluded for the purpose of sub-clause (i) and (ii) of this clause shall be declared as under:

a. Maximum up to one month by the Member Secretary, RPC;
b. Beyond one month and up to three months after the decision at RPC;
c. Beyond three months by the Commission for which the transmission license shall approach the Commission along with reasons and steps taken to mitigate the outage and restoration timeline.

6. Time frame for certification of transmission system availability: (1) The following schedule shall be followed for certification of availability by the Member Secretary of the concerned RPC:

- Submission of outage data along with documentary proof (if any) and TAFPn calculation by Transmission Licensees to RLDC/ constituents

– By the 5th of the following month;

- Review of the outage data by RLDC / constituents and forward the same to respective RPC – by 20th of the month;
- Issue of availability certificate by respective RPC – by the 3rd of the next month.

Appendix-V

FORMULAE FOR CALCULATION OF AVAILABILITY OF EACH CATEGORY OF TRANSMISSION ELEMENTS

For AC transmission system

AVo(Availability of o no. of AC lines) = $$\frac{\sum_{i=1}^{o} Wi(Ti - TNAi)/Ti}{\sum_{i=1}^{o} Wi}$$

AVq(Availability of q no. of ICTs) = $$\frac{\sum_{k=1}^{q} Wk(Tk - TNAk)/Tk}{\sum_{k=1}^{q} Wk}$$

AVr(Availability of r no. of SVCs) = $$\frac{\sum_{l=1}^{r} Wl(Tl - TNAl)/Tl}{\sum_{l=1}^{r} Wl}$$

AVp(Availability of p no. of Switched Bus reactors) = $$\frac{\sum_{m=1}^{p} Wm(Tm - TNAm)/Tm}{\sum_{m=1}^{p} Wm}$$

AVu(Availability of u no. of STATCOMs) = $$\frac{\sum_{n=1}^{u} Wn(Tn - TNAn)/Tn}{\sum_{n=1}^{u} Wn}$$

AV_{xbp}(Availability of an individual HVDC pole) = $$\frac{(Tx - TN)}{Tx}$$

AV_{ybtb} (Availability of an individual HVDC

Back-to-back Blocks) = $$\frac{(Ty - TNAy)}{Ty}$$

For the HVDC transmission system

For the new HVDC commissioned but not completed twelve months;

For first 12 months: $[(AV_{xbp}$ or $AV_{ybtb})x95\%/85\%]$, subject to a ceiling of 95%.

Where,

o	=	Total number of AC lines;
AVo	=	Availability of o number of AC lines;
p	=	Total number of bus reactors/switchable line reactors;
AVp	=	Availability of p number of bus reactors/switchable line reactors;
q	=	Total number of ICTs;
AVq	=	Availability of q number of ICTs;
r	=	Total number of SVCs;
AVr	=	Availability of r number of SVCs;.
U	=	Total number of STATCOM;
AVu	=	Availability of u number of STATCOMs;
W*i*	=	Weightage factor for *i*th transmission line;
W*k*	=	Weightage factor for *k*th ICT;
W*l*	=	Weightage factors for inductive & capacitive operation of *l*th SVC;
Wm	=	Weightage factor for mth bus reactor;
Wn	=	Weightage factor for nth STATCOM.
Ti, , Tk, Tl, , Tm, Tn, Tx, Ty	-	The total hours of i^{th} AC line, k^{th} ICT, l^{th} SVC, m^{th} Switched Bus Reactor & n^{th} STATCOM, x^{th} HVDC pole, y^{th} HVDC back-to-back blocks during the period under consideration (excluding time period for outages not attributed to transmission licensee for the reasons given in Para 5 of the procedure)
$T_{NA}i$,$T_{NA}k$		The non-availability hours (excluding the time period for outages not $T_{NA}l$, $T_{NA}m$, attributable to transmission licensee taken as deemed availability as $T_{NA}n$, $T_{NAn,}$ $T_{NA}x$, $T_{NA}y$ per Para 5 of the procedure) for i^{th} AC line, k^{th} ICT, l^{th} SVC , m^{th} Switched Bus Reactor, n^{th} STATCOM, x^{th} HVDC pole and y^{th}HVDC back-to-back block.