Draft MYT Regulations for Discussion on Haryana Electricity Regulatory Commission (Terms and Conditions for Determination of Tariff for Generation, Transmission, Wheeling and Distribution & Retail Supply under Multi Year Tariff Framework) Regulations, 2019 for the Control Period FY 2020-21 to the FY 2024-25.

JULY, 2019

HARYANA ELECTRICITY REGULATORY COMMISSION
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HARYANA ELECTRICTY REGULATORY COMMISSION

Brief Background, Objects and Reasons

The Electricity Act, 2003 (36 of 2003) was made part of the statute book after receiving assent of the President of India on 26th May, 2003. Further, as per the provisions of clause 185 (3) of the said Act the provisions of "The Haryana Electricity Reforms Act, 1997 (Haryana Act No. 10 of 1998)" not inconsistent with the provisions of the Electricity Act, 2003, were applicable in Haryana. In Haryana, the provisions of the Electricity Act 2003 were deferred by six months from 10th June 2003 vide notification No. 1/4/2003-IP dated 8.9.2003. Therefore, in Haryana, the provisions of the Electricity Act, 2003 as well as the provisions of the Haryana Electricity Reform Act, 1997, which are not inconsistent with the Electricity Act, 2003 are applicable.

In accordance with clause 61(f), the Commission, after following the process prescribed for the purpose, framed and notified the Haryana Electricity Regulatory Commission (Terms and Conditions for Determination of Tariff for Generation, Transmission, Wheeling and Distribution & Retail Supply under Multi Year Tariff Framework) Regulations, 2012. The said Regulations was amended vide notification dated 17.11.2016. Accordingly, the first control period was extended to cover the period from 1.04.2014 to 31.03.2018.

During the aforesaid control period, the Haryana Power Utilities i.e. Haryana Power Generation Company (HPGCL), Haryana Vidyut Prasaran Nigam (HVPN) and the two distribution licensees i.e. Uttar Haryana Bijli Vitran Nigam (UHBVN) and Dakshin Haryana Bijli Vitran Nigam (DHBVN) had filed multi-year ARR/Tariff Petitions including true-up and mid-term performance review. The petitions were considered by the Commission and after inviting comments / objections from the stakeholders / general public and holding public hearings; Order(s) were passed by the Commission in accordance with section 64 of the Act and the Regulations occupying the field.

The petitions required to be filed by the regulated entities have been filed and Order(s) have been issued by the Commission for extended first MYT control period, there is a need to review / re-enact the MYT Regulations for the next control period in the light of experience gained while dealing with various issues that had come up before the Commission.

Resultantly, the Commission has framed the following draft MYT Regulations, 2019 for inviting comments / suggestions / objections from the stakeholders including power utilities / consumers likely to be affected by these Regulations as well as any other interested parties / persons.

It needs to be noted that these draft Regulations are only for discussions and a final view on these Regulations shall be taken by the Commission after considering the feedback received from the Stakeholders as well as the State Advisory Committee.

Draft Notification

The*********, 2019**

Regulation No. HERC/ XX / 2019: - The Haryana Electricity Regulatory Commission, in exercise of the powers conferred on it by section 181 of the Electricity Act 2003 (Act 36 of 2003) and all other powers enabling it in this behalf, after previous publication, hereby frames the following Regulations: -

PART - I PRELIMINARY

1. SHORT TITLE, COMMENCEMENT, EXTENT, AND INTERPRETATION

1.1 These Regulations shall be called the *Haryana Electricity Regulatory Commission (Terms and Conditions for Determination of Tariff for Generation, Transmission, Wheeling and Distribution & Retail Supply under Multi Year Tariff Framework) Regulations, 2019*.

1.2 The *Haryana Electricity Regulatory Commission (Terms and Conditions for Determination of Tariff for Generation, Transmission, Wheeling and Distribution & Retail Supply under Multi Year Tariff Framework) Regulations, 2012* and its subsequent amendments shall stand repealed upon coming into force of these Regulations.

1.3 These Regulations shall come into force w.e.f. the date of publication in the Haryana Government Gazette and shall remain in force till 31st March, 2025, unless otherwise reviewed or extended. No post-facto financial impact shall be provided to any Utility arising after enforcement of these Regulations.

1.4 These Regulations shall extend to the whole of the State of Haryana.

2. SCOPE OF APPLICATION

2.1 These Regulations shall be applicable to all existing and future Generating Companies, Transmission Licensees / SLDC and Distribution Licensees and their successors/assignees, if any, and shall apply where the Commission determines tariff: -

(i) for supply of electricity by a generating company to a distribution licensee,

(ii) for transmission of electricity by a transmission licensee to a distribution licensee or to open access consumers and

(iii) for wheeling & retail supply of electricity by a distribution licensee under Section 62 & 64 of the Act,

(iv) in all other cases where the Commission has the jurisdiction for tariff determination

2.2 In case the tariff has been determined through the transparent process of competitive bidding as per Section 63 of the Electricity Act,2003 i.e., if such tariff has been determined through transparent process of bidding in accordance with the guidelines issued by the Central Government; the Commission shall adopt such tariff in accordance with the provisions of the Act;

2.3 These Regulations shall not apply for tariff determination of renewable energy generation projects. The tariff for such generation projects shall be determined as per *Haryana Electricity Regulatory Commission (Terms & Conditions for determination of Tariff from Renewable Energy Sources, Renewable Purchase Obligation and Renewable Energy Certificate) Regulations, 2017* as amended from time to time.

3. DEFINITIONS AND INTERPRETATION

3.1 **"Act"** means the Electricity Act, 2003 (36 of 2003) as amended from time to time;

3.1 "Accounting Statement" for the purpose of these Regulations, shall include:-

i) Balance sheet / profit and loss statement prepared in accordance with the relevant schedule of the Companies Act in vogue including as may be required under any other Regulations notified by the Commission;

ii) Cash flow / fund flow statement in line with the relevant Accounting Standards of the Institute of Chartered Accountants of India;

iii) Report of the statutory Auditors,

iv) Cost Records, wherever applicable, as prescribed under Section 209(1)(d) of the Companies Act in vogue.

3.2 **“additional capitalization”** means the capital expenditure actually incurred or projected to be incurred after the date of commercial operation of the project and admitted by the Commission after prudence check;

3.3 **“applicant”** means a generating company or a transmission licensee or a distribution licensee who has made an application for determination of tariff or an application for annual performance review in accordance with these Regulations and the Act and includes a generating company or a transmission licensee or a distribution licensee whose tariff is the subject of review by the Commission;

3.4 **“ARR”** means Aggregate Revenue Requirement comprising of allowable Operating Expenses (OPEX), Capital Expenditure (CAPEX) and Return on Equity (RoE) for generation, transmission & SLDC and Wheeling & Retail supply of electricity by a distribution licensee;

3.5 “**Allocation Statement”** means annual financial statement in respect of each of the separate businesses of the Licensees, showing the amount of revenue, costs / expenses, assets, liability, reserves and basis of provisions, if any.

Provided that ‘Allocation’ Statement’ shall not be construed as a substitute for maintaining separate accounting statement for the licensed business and other businesses of the Licensees.

Provided that the licensed business of a distribution and retail supply licensee(s) shall be segregated as Wheeling Business (wires) and Retail Supply Business.

Provided that the licensed business of a transmission licensee(s) shall be segregated as ‘transmission businesses and ‘State Load Despatch businesses.

Provided that the generation company shall segregate its accounting data Unit Wise.

3.6 **“auditor”** means an auditor appointed in accordance with the provisions of section 139 of Companies Act, 2013 or any other law for the time being in the force;

3.7 **“auxiliary energy consumption”** or **'AUXe'** in relation to a period means the quantum of energy consumed by auxiliary equipment of the generating unit / plant such as the equipment being used for the purpose of operating plant and machinery including switchyard of the generating station and transformer losses within the generating unit / plant, expressed as a percentage of the sum of gross energy generated at the generator terminals of the generating unit / all the units of the generating plant;

Provided that AUXe shall not include energy consumed for supply of power to housing colony and other facilities at the generating station and the power consumed for construction works at the generating station;

3.8 **“availability”**

in relation to transmission system for a given period means the time in hours during that period the transmission system is capable to transmit electricity at its rated voltage and shall be expressed in percentage of total hours in the given period and calculated as per the formula specified in Appendix - I to these Regulations;

in relation to a generating station, for a given period, it shall mean the average of the daily declared capacities as certified by the State Load Despatch Centre (SLDC) for all the days during the period expressed as a percentage of the installed capacity minus normative AUXc as provided in these Regulations. The formula specified for the purpose shall be as under: -

$$\text{Availability (\%)} = \frac{10000 \times \sum DC_i}{N \times IC \times (100 - AUX_n)}$$

Where:

IC = Installed Capacity of the generating plant in MW,

DC_i = Average Declared ex-bus Capacity for all days during the period in MW,

N = Number of days in the given period,

AUX_n = Normative Auxiliary Energy Consumption as a percentage of gross generation,

∑ = Summation from i = 1 to N;

3.8 **“bank rate”** shall mean the State Bank of India Marginal Cost of Funds based Lending Rate (MCLR) (one-year tenor), prevalent on the beginning of the financial year.

3.9 **“base year“** means the financial year immediately preceding the first year of the Control Period and used for the purposes of these Regulations;

3.10 **“beneficiary”** in relation to a

(a) “**generating plant”** means the person buying power generated at such a generating plant whose tariff is determined under these Regulations .

(b) **“transmission system”** means the person who has availed of the transmission system on payment of transmission charges determined under these Regulations. This includes a distribution licensee, a transmission licensee, a person who has setup a captive power plant or a generating company including merchant power plant or a consumer availing long-term or medium-term open access utilizing such transmission system. Short-term open access consumers will not be treated as beneficiaries;

(c) **“SLDC”** means the person who uses the services of SLDC and shall include distribution licensee, transmission licensee, a person who has set up captive power plant or a generating company including merchant power plant or a consumer availing long-term or medium-term open access.

3.11 **“block”** in relation to a combined cycle thermal generating plant includes combustion turbine generator(s), associated waste heat recovery boiler(s), connected steam turbine generator and auxiliaries;

3.12 **“CERC”** means the Central Electricity Regulatory Commission;

3.13 **“collection efficiency”** means the ratio of total revenue realised to the total revenue billed during the same financial year. The revenue realisation from arrears pertaining to the same financial year shall be included but revenue realisation from late payment surcharge and arrears pertaining to the previous years shall not be included for computation of collection efficiency;

3.14 **“Commission”** means the Haryana Electricity Regulatory Commission;

3.15 **“conduct of business Regulation”** means Haryana Electricity Regulatory Commission (Conduct of Business) Regulations, 2004 as amended from time to time;

3.16 **“control Period”** means a multi-year tariff period fixed by the Commission from time to time. The control period shall be from 1st April 2020 to 31st March 2025.

3.17 **“core business”** for the purpose of these Regulations, means the regulated activities of the generating company or the transmission licensee or the distribution licensee, as the case may be, and does not include any other business;

3.18 **"cut-off date"** means 31st March of the year closing after two years of the year of commercial operation of the project, and in case the project is declared under commercial operation in the last quarter of a year, the cut-off date shall be 31st March of the year closing after three years of the year of commercial operation;

3.19 **"Change in Law"** shall mean occurrence of the following events:-

i) Enactment of any new Indian law and duly entered into the Statute Book;

ii) Adoption, amendment, modification, repeal or re-enactment of any existing Indian law;

iii) Interpretation to Indian Law given by a Court / Tribunal of competent jurisdiction.

3.20 **"date of commercial operation (COD)"** means

(a) In relation to a generating unit, the date declared by the generating company after demonstrating the maximum continuous rating (MCR) or Installed Capacity (IC) through a successful trial run after seven days' notice to the beneficiaries and scheduling shall commence from 00.00 Hrs. after the successful completion of trial run. Additionally, the Generator shall certify that the said generation unit fully comply with the applicable provisions and technical standards of the Central Electricity Authority (Technical Standards for Construction of Electrical Plants an Electric Lines) Regulations, 2010 and Haryana Electricity Regulatory Commission (Grid Code) Regulations, as amended and in vogue and / or re-enacted.

(b) In relation to the generating plant, the date of commercial operation of the last unit or block of the generating plant;

(c) In relation to Hydro Power Plants including PSP, CoD shall be the date declared by the Generating Company after demonstrating peaking capacity corresponding to the installed capacity of the generating station through successful trail run. Scheduling shall commence from 00.00 Hrs. after completion of the trial run. Additionally, the Generator shall certify that the said generation unit fully comply with the applicable provisions and technical standards of the Central Electricity Authority (Technical Standards for Construction of Electrical Plants an Electric Lines) Regulations, 2010 and Haryana Electricity Regulatory Commission (Grid Code) Regulations, as amended and / or re-enacted.

Provided further, that in case a hydro generating station, with pondage, is unable to demonstrate peaking capacity corresponding to the installed capacity due to insufficient reservoir / pond level, the CoD shall be consider as the date of commercial operation of the last unit of the generating unit. However, it shall be mandatory for such hydro generator to demonstrate peaking capacity corresponding to the installed capacity as and when such reservoir / pond level is achieved. The same in the case of run-of-river shall be as soon as sufficient water flow is available subsequent to the lean inflow season.

(d) in relation of transmission system, the date from 00.00 Hrs of charging the transmission system or part thereof to its rated voltage level or seven days after the date on which it is declared ready for charging by the transmission licensee, but is not able to charge for reasons not attributable to the transmission licensee, its suppliers or contractors.

Provided in the case of dedicated transmission line / sub-station, the Generating Company and the Transmission Licensee shall ensure that the transmission system is commissioned well within the time frame agreed upon by them. However, in case the delay in commissioning is on account of the generating station concerned, the transmission licensee shall approach the Commission with an appropriate petition for approval of the CoD of such transmission system or transmission element as such.

3.21 **"declared capacity"** or **'DC'** means the capability of generating plant to deliver ex-bus electricity in MW declared by such generating plant in relation to any time-block of the day or whole of the day, duly considering the availability of fuel or water;

3.22 **"De-capitalisation"** means reduction in Gross Fixed Assets (GFA) and reflected in the Fixed Assets Register subsequent to removal of the assets as admitted by the Commission;

3.23 **"Design Energy"** in relation to hydro power plant means the quantum of energy that could be generated in a 90 percent dependable year with 95 percent installed capacity of the generating station;

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

3.25 **"Distribution wires Business"** means the business of operating and maintaining the system for wheeling of electricity in the area of supply of the distribution licensee;

3.26 **“existing generating plant”** means generating plants declared under commercial operation on or a date prior to 31st March 2020;

3.27 **“existing transmission system”** means the transmission system declared under commercial operation on or a date prior to 31st March 2020;

3.28 **“force majeure events”** means, with respect to any party, any event or circumstance which is not within the reasonable control of, or due to an act or omission of that party and which, by the exercise of reasonable care and diligence, that party is not able to prevent, including, without limiting the generality of the foregoing,

i. acts of God, including but not limited to lightning, storms, earthquakes, floods and other natural disasters;

ii. strikes, lockouts, go-slow, bandhs or other industrial disturbances;

iii. acts of public enemy, wars (declared or undeclared), blockades, insurrections, riots, revolution, sabotage and civil disturbance;

iv. unavoidable accident, including but not limited to fire, explosion, radioactive contamination and toxic dangerous chemical contamination;

v. any shutdown or interruption of the Grid, which is required or directed by the State or Central Government or by the Commission or the State/Regional Load Despatch Centre; and

vi. any shut down or interruption, which is required to avoid serious and immediate risks of a significant plant or equipment failure;

3.29 **“gross calorific value”** or ‘**GCV’** in relation to a thermal power generating plant means the heat produced in kCal by 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;

3.30 **“station heat rate”** or ‘**SHR’** means the heat energy input in kCal required to generate one kWh of electrical energy at generator terminals;

3.31 **“infirm power”** means electricity injected into the grid prior to the Scheduled COD or the date of commercial operation of a unit or block of a generating plant whichever is earlier;

3.32 **“installed capacity”** or **'IC**’ means the summation of the name plate capacities of all the units of the generating plant or the capacity of the generating plant (reckoned at the generator terminals) approved by the Commission from time to time;

3.33 **“licensee”** means any person or persons granted license under Section 14 or exempted under Section 13 of the Act including deemed licensee

3.34 **“licensed business”** means the functions and activities, which the licensee(s) is required to undertake in terms of the licence granted by the Commission or as a deemed Licensee(s) under the Act;

3.35 **“long-term transmission consumer”** means a distribution licensee or a person having a long-term lien for a period as defined in the open access Regulations notified by the Commission from time to time, over an intra-State transmission system by paying all applicable charges for which appropriate agreement has been entered into with the transmission licensee;

3.36 a) **“market operation function”** means functions of scheduling, dispatch, metering data collection, energy accounting & settlement, transmission loss calculation & apportionment, operation of pool account & congestion charge account, administering ancillary services & information dissemination and any other function assigned to the SLDC by the Electricity Act, 2003 or by HERC Regulations and Orders;

b) **“market operation charges”** means the charges, as approved by the Commission, to be recovered by the SLDC from the users for performing market operation functions.

3.37 **“maximum continuous rating”** or **‘MCR’** in relation to a unit of the thermal power generating plant 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 gas based thermal power generating plant 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;

3.38 **“medium term transmission consumer”** means a person having a medium-term lien for a period as defined in the open access Regulations notified by the Commission from time to time over an intra-State transmission system by paying all applicable charges;

3.39 (a) **“new generating plants”** means generating plants declared under commercial operation on a date after 31st March 2020;

(b) **“new transmission system”** means the transmission system declared under commercial operation on a date after 31st March 2020;

3.40 **“operation and maintenance expenses”** or **“O&M expenses”** mean the expenditure incurred on operation and maintenance of the generating plant or transmission system or distribution system, as the case may be, including part thereof, and includes the following expenditure:

a. Employee cost (EC)

b. Repair and Maintenance (R & M) expenses;

c. Administration and General (A & G)expenses;

3.41 **“plant load factor”** or **'PLF’** for a given period, means the total sent out energy corresponding to actual 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:

$$\text{PLF (\%)} = \frac{10000 \times \sum G_i}{N \times IC \times (100 - AUX_n)}$$

Where:

IC	=	Installed Capacity of the generating plant in MW,
G_i	=	Actual ex-bus Generation in MW for the ith time block of the period,
N	=	Number of Time Blocks during the period,
AUX_n	=	Normative Auxiliary Energy Consumption as a percentage of gross generation,
∑	=	Summation from i = 1 to N;

3.42 **“project”**

(a) In relation to generation business means a generating plant and includes all components of generating facility such as power generating plant and generating units of the scheme, as apportioned to power generation;

(b) In relation to transmission business means a transmission system comprising specified transmission lines, sub-stations and associated equipment.

(c) In relation to a distribution business means a distribution system comprising specified distribution lines, sub-stations and associated equipment.

3.43 **“Prudence Check”** means scrutiny of reasonableness of expenditure incurred or proposed to be incurred, financing plan, use of efficient technology, cost and time over-run and such other factors as may be considered appropriate by the Commission for determination of tariff;

3.44 **“rated voltage”** means the manufacturer’s design voltage at which the transmission/distribution system is designed to operate or such lower voltage at which the line is charged, for the time being, in consultation with supplier and receiver of electricity

3.45 **“retail supply business & retail supply licensee”** means the business of sale of electricity by a Distribution Licensee(s) to the various categories of consumers within the area of supply in accordance with the terms of the Licence for distribution and retail supply of electricity;

3.46 “**revenue”** means the amount billed or assessed to be billed at the applicable tariff including any fuel price adjustments in the case of a Generating Company and in the case of distribution licensees shall be inclusive of MMC, FSA or any other charges i.e. power factor surcharge, load / demand surcharge etc. for sale of power.

3.47 **“scheduled generation”** for any given time or time block means the quantum of ex-bus energy scheduled by the State Load Dispatch Centre to be injected into the grid by a generating plant.

3.48 **“short-term transmission consumer”** in the context of usage of Transmission System means a person having short-term lien for a period as defined in the open access Regulations notified by the Commission from time to time over an intra-State Transmission System by paying all applicable charges;

3.49 **“State”** means State of Haryana;

3.50 “**State Load Dispatch Centre**” or **‘SLDC’** means the centre established by the State Government under section 31 of the Act for purposes of exercising the powers and discharging the functions under Section 32 of the Act;

3.51 a) “**System Operation Functions**” includes monitoring of grid operations, supervision and control over the intra – state Transmission System, real – time operations for grid control, system restoration following grid disturbances, compiling and furnishing data pertaining to system operation, congestion management-ordination with RLDC, black start co-ordination and any other functions assigned to the SLDC by the Electricity Act, 2003 or by HERC Regulations and Orders.

b) "**System Operation Charges**" means the charges, as approved by the Commission, to be recovered by the SLDC from the users for performing system operation functions.

3.52 "**tariff"** means the schedule of charges for generation, transmission and distribution & retail supply of electricity with terms and conditions applicable thereof;

3.53 "**transmission service agreement**" or '**TSA**' means an agreement, contract, memorandum of understanding, or any such covenant, entered into between the transmission licensee and the long-term transmission consumer(s), as approved by the commission, for the use of transmission system

3.54 "**transmission system**" means a transmission line or a group of transmission lines inter-connected together with or without associated sub-stations including equipment associated with transmission lines and sub-stations;

3.55 "**unit"** in relation to a thermal power generating plant means steam generator, turbine-generator and auxiliaries, or in relation to a combined cycle gas based thermal power generating plant, means turbine-generator, waste heat recovery plant and auxiliaries;

3.56 "**unscheduled interchanges**" or '**UI**' means the unscheduled interchange of energy as mentioned in the Indian Electricity Grid Code or as defined in the Intra State ABT Regulations of HERC as may be notified from time to time;

3.57 "**wheeling**" means the operation whereby the distribution system and associated facilities of a transmission licensee or distribution licensee, as the case may be, are used by another person for the conveyance of electricity on payment of charges to be determined under section 62 of the Act;

3.58 "**wheeling business**" means the business of operating and maintaining a distribution system for conveyance of electricity in the area of supply of the distribution licensee;

3.59 **"year"** means the financial year i.e. a period commencing on 1st April of a calendar year and ending on 31st March of the subsequent calendar year;

Words appearing in these Regulations and not defined shall bear the same meaning as in the Act. All other expressions used herein but not specifically defined herein but defined in the Act shall have the meaning assigned to them in the Act. The expressions used herein but not specifically defined in the Regulations or in the Act but defined under Haryana Electricity Reform

Act, 1997 (Act 10 of 1998) shall have the meaning assigned to them under the said Act, provided that such definitions in the Haryana Electricity Reform Act, 1997 are not inconsistent with the provisions of the Electricity Act, 2003.

3.60 **“Technical Minimum Schedule”** in respect of State Generating Stations shall have the same meaning as provided in Regulation 34 of these Regulations.

PART II - MULTI YEAR TARIFF FINANCIAL PRINCIPLES

4. GENERAL

4.1 The Commission, in specifying these Regulations, is guided by the provisions contained in Sections 61 and 62 of the Electricity Act, 2003 the National Electricity Policy and the National Tariff Policy notified by the Central Government under Section 3 of the Act as amended from time to time as well as the relevant Regulations notified by the Central Commission.

4.2 The Commission shall adopt Multi Year Tariff (MYT) framework for determination of ARR/tariff for each year of the Control Period from the FY 2020-21 i.e. 1.04.2020.

4.3 Basis of implementation of Multi Year Tariff framework:-

The implementation of MYT framework shall be based on the following:-

(a) The capital investment plan and the business plan for a period not less than the control period to be submitted by the utilities for their respective businesses along with the MYT Petition;

(b) The forecast for each year of the control period of the various financial and operational parameters of ARR, based on reasonable assumptions, to be filed by the utilities for their respective businesses;

(c) The trajectory for specific variables as may be stipulated by the Commission, where the performance of the utilities for their respective businesses is sought to be improved under incentive and penalty framework;

(d) The mid-year performance review vis-a-vis the approved forecast and variations in performance of controllable and uncontrollable items;

Provided that the Generating Company and the Licensees shall submit their Accounting Statements / Segmented Accounts / Allocation Statement to support their claims / assessment including reasons of variations in various expenses, at the time of performance review / Truing-up.

(e) The mechanism for sharing approved gains or losses on account of controllable items;

(f) The mechanism for pass through of approved gains or losses on account of uncontrollable items.

Provided that the Commission shall apply prudence check with regard to the following:-

i) Revenue from Sale of Power- whether consumer category wise sales projections are backed up by consumer category wise time series data on connected load / contract demand, sales trend, number of consumers and any abnormal increase / decrease has been adequately explained.

ii) Billing Efficiency - measured as a percentage of Units billed by the distribution licensee to the total units injected into the distribution system.

Provided that in the case of a transmission licensee, the same shall be expressed as a percentage of units injected into the transmission system'

iii) Revenue Collection Efficiency- shall be measured as a percentage of revenue realised by a generating company / Licensee against the total amount billed excluding arrears.

iv) Reduction in outstanding receivables from consumers including un-paid RE Subsidy, if any and beneficiaries in the case of transmission licensees and Generating Company.

v) Percentage of consumers billed on the basis of meter reading to the number of consumers billed on average / assessed basis.

vi) Revenue Expenditure including interest payments on term loan / working capital loans vis-a-vis revenue earned. Any revenue expenditure in excess of revenue earned shall be supported by a detailed justification including source of funding at the time of Truing-up;

vii) Merit Order scheduling of power in line with requirement and additional revenue earned over and above the average power purchase cost on trading of surplus power;

viii) Assessment of financial and physical progress of Capital Expenditure under each heads vis-a-vis the schedule submitted and approved by the Commission. In case of any deviation in Capital Expenditure including Capitalisation, the generating company / Licensee shall submit a detailed justification at the time of truing-up. The loan drawl should be matched with physical progress of Capital Works undertaken under each head.

4.4 Tariff during the control period: The Commission shall determine the ARR for each year of the control period and tariff for the first year of the control period separately for Generation Company (ies), transmission licensee(s) / SLDC and distribution licensee(s).

4.5 The tariff applicable to each business in each of the remaining years of the control period shall be notified by the Commission through a separate order after taking into consideration the following:-

a) Mid-year performance review;

b) Specified performance targets;

c) True-up of uncontrollable items as defined in Regulation 8.3.

4.6 There will be no true-up of the controllable items except on account of Force Majeure events or on account of variations attributable to uncontrollable items. The variations in the controllable items, as defined in Regulation 8.3, over and above the norms specified will be governed by incentive and penalty framework specified in these Regulations.

4.7 The tariff determined by the Commission and the directions given in the MYT order shall be quid pro quo and mutually inclusive. The tariff determined shall, within the time period specified in the order, be subject to the compliance of the directions by the generating company and the licensees to the satisfaction of the Commission. Non-compliance of the directions shall lead to such amendment, revocation, variations and alterations in the tariff, as may be ordered by the Commission. Further non-compliance of directions given in the tariff order may also lead to invocation of the provisions of section 142 of the Electricity Act, 2003.

Provided the Generation Company and / or the Licensee may seek extension in time for compliance of the directives with appropriate justification to the satisfaction of the Commission.

4.8 The tariff determined by the Commission shall continue to operate till it is modified or revised by the Commission.

5. PLANT WISE COMPUTATION OF TARIFF FOR GENERATING COMPANY

5.1 The tariff for the generating company shall be determined, plant-wise. Following shall be the categorization for the existing thermal plants of State Generator i.e. HPGCL:-

S.No	Plant	Capacity (MW)
1	Panipat TPS Unit 5 & 6	Unit-5: 210 Unit-6: 210
2	Panipat TPS Unit 7 and 8	Unit-7: 250 Unit-8: 250
3	DCR TPS Yamunanagar Unit 1 and 2	Unit-1: 300 Unit-2: 300
4	Rajiv Gandhi TPS Khedar (Hisar) Unit 1 and 2	Unit-1: 600

		Unit-2: 600
5	Total Existing Thermal Capacity (HPGCL)	2720 MW

5.2 The generating company shall prepare its annual accounts in a manner such that all individual plants are treated as separate business units. Any new plant commissioned during the control period shall be treated at aggregate plant level and not unit-wise for tariff computation and scheduling purposes

5.3 The operational norms for each generating plant shall be specified unit-wise. Therefore, the statement of account should also include the unit-wise performance parameters for each plant.

5.4 The generating company shall file the tariff petition as per the above categorization. All plants indicated above and the plants which may be commissioned during the control period shall have separate interface metering with the transmission licensee(s) as per CEA (Installation and Operation of Meters) Regulations, 2006 as amended from time to time and, as and when intra state ABT is implemented, different power plant, as categorised above, shall be scheduled separately as per the intra State ABT Regulations as may be notified by the Commission from time to time.

Provided that a Generation entity may file an application for determination of provisional tariff for a new generating station or Unit(s) six months prior to the scheduled date of commissioning .

5.5 For the plants which are not covered under ABT i.e. Western Yamuna Canal Hydro Project, Bhudkalan and Kakroi Hydro Power Plants, a single part tariff based on a normative PLF shall be determined by the Commission.

Provided the Commission may determine tariff for hydro power projects up to 25 MW separately as per the norms specified in the HERC RE Tariff Regulations in vogue.

5.6 Target availability shall be construed as target PLF till the time power plants are brought under intra-State ABT framework.

6. ARR / Tariff OF TRANSMISSION BUSINESS AND SLDC

6.1 The transmission licensee i.e. Haryana Vidyut Prasaran Nigam (HVPN) has been notified as the State Transmission Utility by the Haryana Government as per Section 39(1) of the Act and has also been entrusted with the operation of SLDC.

Accordingly, HVPN shall submit separate ARR for its transmission business and SLDC business, as long as it remains under its control, as per provisions of these Regulations. The ARR for each business shall be based on the audited accounts of the corresponding business. After a Government company or an authority or a corporation is established or constituted for operation of SLDC by or under any State Act, as may be notified by the State Govt. as per provisions of Section 31 of the Act, the ARR for SLDC business shall be submitted by such Government company, authority or corporation, as the case may be, as per provisions of these Regulations.

6.2 The Commission may require the STU or the Government company/Authority/Corporation established for operation of SLDC or the SLDC itself to submit such details/information as may be required for determination of SLDC charges. Further, the Commission may give directions to SLDC in relation to the role and functioning of SLDC.

6.3 The transmission tariff determined by the Commission shall comprise all or any of the following:-

i) Transmission System Access Charges (TSAC);

ii) Annual Transmission Charges (ATC);

iii) Per Unit charges for energy transmitted (Rs/kWh or kVAh);

iv) Reactive Energy Charges (Rs / kVARh);

ATC, for each financial year of the control period shall be designed to recover the ARR of the Transmission Licensee for the respective financial year as approved by the Commission.

The ARR shall comprise of the following:-

i) Operation & Maintenance Expenses (O&M)

Administrative & General Expenses (A&G);

Employees Expenses (working & retired);

Repair & Maintenance (R&M);

ii) Depreciation;

iii) Interest Expenses

on term loan (IoTL);

on working capital loan (IoWC);

iv) Return on Equity (RoE)

v) Income Tax / MAT

vi) Foreign Exchange Rate Variation (FERV) applicable on foreign currency loans.

Provided that Non-Tariff Income, Income from Open Access Consumers and income from intrastate transmission lines designated as interstate transmission lines wherein Yearly Transmission Charges are recovered through Point of Connection (PoC) charges as per CERC Regulations / Order(s), shall be deducted while determining ATC recoverable by the transmission licensee(s) from its long-term beneficiaries.

Provided that Non-Tariff Income shall include but not limited to Income from rent of land / building, sale of scrap, investments/advances, delayed payment surcharge, rentals, supervision charges for capital works, sale of tender/documents/advertisements etc.

The Commission may also implement a transmission pricing mechanism for transmission licensee in such a way so as to align intra-State transmission pricing mechanism with the inter-State transmission pricing mechanism as adopted by the Central Electricity Regulatory Commission in line with the National Tariff Policy of the Government of India.

Provided the existing transmission licensee / STU are able to collect and collate sufficient data / underlying assumptions including voltage wise transmission loss allocation factor w.r.t. distance sensitive cost of transmission after undertaking a detailed study relating the hybrid method (PoC methodology of CERC bringing together the marginal and average participation approach) and load flow study including its likely impact on the beneficiaries of transmission services along with the timelines for implementing the same.

The aggregate revenue requirement net of deductions and other income for transmission business as approved by the Commission for the control period shall be the total cost of the transmission system (ATC). The ATC shall be recovered from all the users of the Transmission System for the respective year(s) of the control period as per the formula specified herein.

$$ATC = \sum^{n}_{i=1} ARR_i - NTI_i - OI_i\ )$$

The notations are as explained below:-

ATC = Total Transmission System Cost of the relevant year of the Control Period.

n = Number of Transmission Licensee (in case more than one except those selected through competitive bidding mode u/s 63 of the Electricity Act, 2003).

NTI = Non-Tariff Income as approved by the Commission for the ith year of the Control Period.

OI = Other Income i.e. income from any business of the transmission licensee other than the regulated business income / revenue from which is required to be shared for the ith year of the Control Period.

Provided that the ATC, as determined by applying the ibid formula shall be either:-

i) Shared by the long-term beneficiaries of the Transmission System in proportion to the respective transmission system of each user of the transmission system allotted in the intra-state transmission system.

Or

Depending on the availability and reliability of the recorded data_.

ii) Average of the respective projected simultaneous maximum peak (co-incidental system peak) and non-coincidental peak for each long-term transmission system users.

Provided that the above shall be subject to truing – up on availability of actual data of co-incidental and non-coincidental system peak as per the dispensation of truing-up provided in these Regulations.

Provided also that the base transmission tariff for short term users including Open Access Consumers shall be determined in accordance with the following formula:-

$$TT = ATC / \sum^{n}_{i=1} \text{(Energy Transmitted by Transmission Licensee)}$$

Where:

TT = Transmission Tariff (Rs/kWh)

ATC = Total Transmission System Cost of the relevant year of the Control Period.

Provided that the energy (kWh) transmitted by the transmission licensee(s) shall be as projected by the transmission licensees in their MYT petition and approved by the Commission after following the due process. Any variation in projected / approved and actual shall be trued up at the time of mid-term on availability of audited data / information.

6.4 **Provisional Transmission Tariff**

The Commission, on a petition filed by the existing Transmission Licensee or a new Transmission Licensee in Haryana, shall determine and approve transmission tariff under these Regulations on a provisional basis.

Provided a petition for determination of provisional transmission tariff is filed before the Commission at least six months prior to the anticipated / scheduled date of commercial operation of the transmission assets.

The petition for determination of provisional transmission tariff shall inter alia include the following:-

i) Capital Expenditure incurred and projected to be incurred up to the date of scheduled commercial operation including additional capital expenditure incurred duly certified by the statutory auditor.

ii) Details of all the underlying assumptions

iii) Based on the above, provisional transmission tariff shall be determined and allowed from the scheduled date of commercial operation.

Provided in the case the CoD is delayed beyond six months from the date of Commission's Order determining / approving provisional transmission tariff, the said Order shall cease to be applicable and the Petitioner shall be required to file a tariff petition afresh after the date of CoD.

iv) The transmission licensee shall file a petition for determination of final tariff transmission tariff within six months from the date of CoD based on the audited capital expenditure and capitalisation as o the date of CoD of the transmission project.

v) The Commission shall determine final tariff based on prudence check of the audited capital expenditure and capitalisation thereto as on date of CoD including but not limited to benchmarking capital expenditure and capitalisation against similar transmission projects commissioned elsewhere in the country.

Provided where the final transmission tariff determined / approved by the Commission is +/- 5% of the provisional tariff, the differential amount shall be restored / recovered from the beneficiaries along with interest rate as may be considered reasonable by the Commission subject to the ceiling of the interest rate allowed to the transmission licensee on its working capital loans.

7. WHEELING (PURE WIRES) AND RETAIL SUPPLY BUSINESS

The distribution licensee shall segregate the accounts of the licensed business into Wheeling Business and Retail Supply Business and submit separate ARRs for respective businesses. The ARR for wheeling business shall be used to determine wheeling charges recoverable from open access consumers and the ARR for Retail Supply Business to determine retail supply tariff for sale of electricity to different categories of consumers of the licensee which will be inclusive of wheeling charges.

Provided that till such time the accounts are segregated as per provisions of these Regulations, the distribution licensee shall prepare an allocation statement to apportion costs and revenues to respective business. The allocation statement shall be approved by the Board of Directors of the distribution licensee and accompanied with an explanation of the methodology which should be consistent over the control period.

8. MYT APPROACH

8.1 **Base Line values**- The Commission shall determine baseline values for various financial and operational parameters of ARR for the control period taking into consideration the figures approved by the Commission in the past, actual average figures of last three years, audited accounts, estimate of the figures for the relevant year, Industry benchmarks/norms and other factors considered appropriate by the Commission;

8.2 **Control Period** – The first control period under Multi-Year Tariff framework shall be a period of five (5) years commencing from 1st April 2020.

8.3 The Aggregate Revenue Requirement of the Distribution Business (wires) to be recovered through wheeling charges of the distribution licensee(s) shall comprise the following:-

i) Interest on Term Loan

ii) Interest on normative Working Capital

iii) Interest on deposits from distribution system users

iv) Depreciation

v) Operation & Maintenance Expenses

vi) Return on average (opening + closing) Equity for the relevant year

vii) Provision for bad and doubtful debts as may be admitted by the Commissions subject to the ceiling of 0.5% of the account receivable as per the audited accounts of the relevant year.

Provided that the wheeling charges shall be net of i) Non-Tariff Income, ii) Income from Other Business (ARR – (Non-Tariff Income + Income from Other Business). Non-Tariff Income shall include rent from land / building, sale of scrap, investment income, delayed payment surcharge and interest thereto, interest earned on advances to suppliers / contractors, rental income from staff quarter / guest houses, income from schedule of charges, income from supervision charges for capital works, income from sale of tender documents, income from advertisements etc.

Provided also, prior period income / expenses shall be allowed by the Commission at the time of truing-up based on the audited accounts on a case to case basis subject to prudence check. However, all penalties payable by the distribution licensee arising from Commission's order, courts / tribunal, CGRF / Ombudsman shall not be allowed to be recovered through ARR.

8.3.1 The method of recovery of the Distribution charges (wires business) shall either be in the basis of energy wheeled basis (Rs. kWh / kVAh) or on the basis of contracted capacity (Rs/kW/kVA/month).

8.3.2 The Distribution Loss / Aggregate Technical & Commercial loss shall be as determined by the Commission in the Order in the MYT petition filed by the power utilities.

Provided that for wheeling transactions, the voltage wise wheeling loss shall be determined by the Commission in the MYT petition filed by the power utilities.

Provided for the above, the voltage wise technical losses shall be projected by the power utilities based on system configuration and capital investment plan.

8.3.3 O&M Expenses (Wires Business) shall comprise of Employees Cost, Repair & Maintenance Expenses (R&M), Administrative & General Expenses (A&G).

Provided that between Distribution (Wires) and Retail Supply Business, the employee's expenses shall be linked to wheeled energy / energy sales and number of consumers in 50:50 ratio, A&G expenses shall be linked to the number of consumers and R&M expenses to the opening Gross Fixed Assets (GFA).

Provided that approved O&M expenses for Distribution (Wires) and Retail Supply Business shall be arrived at on the basis of actual audited figures for the FY 2015-16, FY 2016-17 and FY 2017-18.

Provided further that an escalation factor of **4%** per annum shall be considered to arrive at the applicable O&M norm for the relevant financial year of the control period.

8.3.4 The Aggregate Revenue Requirement of the Retail Supply Business to be recovered through retail supply tariff of the distribution licensee(s) shall comprise the following:-

i) Power Purchase Cost

ii) Transmission Charges (Inter State & Intra State)

iii) Interest (Term Loan and normative Working Capital Loan, Consumer Security Deposit)

iv) Depreciation

v) Operation & Maintenance Expenses

vi) Provision for bad and doubtful debt subject to a ceiling of 0.5% of the account receivable as per the latest available audited accounts.

vi) Return on Equity Capital

Provided that the ARR computed as per above shall be net of Non-Tariff Income, income from Other Business, receipts from cross – subsidy surcharge and additional surcharge etc.

Provided further that the prior period expenses shall be considered at the time of truing – up on a case to case basis subject to prudence check. However, all penalties payable by the distribution licensee arising from Commission's order, courts / tribunal, CGRF / Ombudsman shall not be allowed to be recovered through ARR.

Provided that the distribution loss trajectory shall be as agreed upon in the UDAY scheme and the same shall not be re-visited by the Commission. The Distribution licensee(s) shall submit the details of circle wise / division wise losses under its licensed area

8.3.5 Power Procurement: The distribution licensee (shall procure power from the sources for which Power Purchase Agreement has been approved by the Commission.

Provided that for any procurement from medium to short term contracts are required, the distribution licensee(s) shall obtain prior approval of the Commission with supporting data / details and proper justification.

Provided that the power procurement plan submitted for the control period shall comprise of quantitative forecast of quantum and cost of the unrestricted base load and peak load demand in its licensed area. An estimate of month wise availability of power to meet base load and peak load demand both in terms of megawatt (MW) and Million Units (kWh). The procurement plan shall inter-alia include action plan regarding energy conservation, energy efficiency and demand side management.

Provided further that the power procurement plan shall also include procurement of renewable energy or renewable energy certificate in case the available RE Sources are not sufficient to meet with the RPO trajectory as specified by the Commission including backlog, if any allowed by the Commission during the previous year(s).

Provided that the Distribution licensee(s) shall share its power procurement plan with the State Transmission Utility in order to maintain consistency in the intra-state transmission system plan.

8.3.6 Power Purchase Agreement (PPA) – The Commission shall consider approval of PPA in the light of the approved power procurement plan either u/s section 86(1)(b) or 63 of the Act.

Provided that all such PPAs shall be submitted in the Commission with complete documentations and adherence to the relevant guidelines and policy. Further, no PPA / Supplementary Agreement shall be executed without the prior approval of the Commission.

Provided that the Commission shall approve the PPA or reject the same after holding public / Stakeholders consultation on the same and if the same is not in conformity to the level of transparency required including competitiveness of the project or is found to be in violation of relevant statute / guidelines, the same shall not be admitted and rejected outrightly.

The O&M norms for the retail supply business shall be same as in the case of Distribution (Wires) business.

8.3.7 **Controllable and Uncontrollable items of ARR**

(a) For the purpose of this Regulation, the items of ARR shall be identified as 'controllable' or 'uncontrollable'. The variation on account of uncontrollable items shall be treated as a pass-through subject to prudence check/validation and approval of the Commission;

Provided that the Commission may allow variations in controllable items on account of Force Majeure events and also those attributable to uncontrollable factors as pass-through in the ARR for the ensuing year based on actual values submitted by the generating company and licensees and subsequent validation and approval by the Commission during true-up.

(b) The items in the ARR shall be treated as 'controllable' or 'uncontrollable' as follows:

ARR Element	**Controllable/ Uncontrollable**
Interest and Finance Charges	Controllable
Return on Equity	Controllable
Availability	Controllable
Plant availability factor	Controllable
Heat Rate	Controllable
Auxiliary Energy Consumption	Controllable
Secondary Fuel Oil Consumption (SFC)	Controllable
O&M Expenses (excluding terminal liabilities with regard to employees on account of changes in pay scales or dearness allowance due to inflation)	Controllable
Terminal liabilities with regard to employees on account of changes in pay	Uncontrollable

ARR Element	Controllable/ Uncontrollable
scales or dearness allowance due to inflation	
Depreciation	Controllable
Transit loss of coal	Controllable
Capital Expenditure	Controllable
All statutory levies and taxes, if any excluding tax on Income	Uncontrollable
Fuel Price (excluding that pertaining to domestic coal procured through e-auction/open market and imported coal)	Uncontrollable
Fuel Price pertaining to domestic coal procured through e-auction /open market and imported coal	Controllable
GCV of Fuel (excluding domestic coal procured through e-auction/open market and imported coal)	Uncontrollable
GCV of domestic coal procured through e-auction/open market and imported coal	controllable
Distribution Losses (technical and commercial including bad debts)	Controllable
Collection Efficiency	Controllable
Energy Sales(excluding interstate and inter Discom energy sales)	Uncontrollable
Interstate and inter Discom energy sales	Controllable
Power Purchase Price (other than for short-term power purchase and UI)	Uncontrollable
Power Purchase Price for short-term power and UI	Controllable
Power Purchase Quantum (MU)	Controllable
Intra State Transmission losses	Controllable
Quality of Supply as per Standard of Performance unless exempted	Controllable
Non-Tariff income	Uncontrollable

8.4 **Norms:** Commission shall determine norms for 'controllable' items and where the performance of the utilities for their respective businesses is sought to be improved upon through incentive and penalty framework, trajectory for specific variables may be stipulated. The variations in the controllable items over and above the specified norms will be governed by incentive and penalty framework specified in these Regulations.

8.5 **Forecast of expected revenue from tariff:** The applicant shall develop the forecast of expected revenue from tariff and charges and submit the same along with complete supporting details, including but not limited to the details of past performance, proposed initiatives for achieving efficiency or productivity gains, technical studies or secondary research and contractual arrangements, to enable the Commission to assess the reasonableness of the forecast.

9. CAPITAL INVESTMENT PLAN

9.1 The generating company and the licensees, in respect of their respective businesses, shall file for approval of the Commission a capital investment plan along with the MYT petition for a period covering at least the entire control period. The capital investment plan shall be project/scheme wise and for each scheme/project shall include:

(a) Purpose of investment

(b) Capital Structure;

(c) Capitalization Schedule;

(d) Financing Plan including identified sources of investment;

(e) Details of physical parameters / targets;

(f) Cost-benefit analysis and payback period;

(g) Envisaged reduction in O&M cost/losses;

(h) Ongoing projects that will spill into the year under review and new projects (along with justification) that will commence but may be completed within or beyond the control period.

9.2 Purpose of investment shall include:

(i) for a generation company- generation capacity growth, replacement of assets, renovation and modernization,

	reduction in average per unit cost of generation etc;
(ii) for a transmission licensee-	power evacuation, system augmentation, network expansion, replacement of assets, reduction in transmission losses, improvement in transmission service and reliability of supply, reduction in per MW transmission cost, IT related projects etc.
(iii) for a distribution licensee-	meeting load growth/ sales forecast (MUs), distribution loss reduction, non-technical loss reduction, replacement of assets, meeting reactive energy requirements, improvement in metering, consumer services, collection efficiency, quality and reliability of supply etc.

Note: The Capital Investment by transmission licensee(s) in network expansion shall be based on load flow studies and in accordance with the requirements of Haryana Grid Code.

9.3 The capital investment plan, in case of a generation company, will be commensurate with generation capacity growth, renovation & modernization requirements etc.

In case of a transmission licensee, the capital investment plan will be commensurate with load/generation capacity growth and will be linked to improvement in quality of transmission service, reliability, metering and reduction in transmission losses.

The capital investment plan in case of a distribution licensee shall be commensurate with sales forecast (MUs) / load growth of the state, distribution/non-technical loss reduction targets, improvements envisaged in metering, collection efficiency, reliability and quality of supply etc.

9.4 Capital Investment for renovation and modernization in case of a transmission licensee and a generation company shall be made through an application with a detailed project report (DPR) elaborating the following elements: (i) Complete scope and justification; (ii) Estimated life extension of the generation/transmission asset; (iii) Improvement in performance parameters; (iv) Cost-benefit analysis; (v) Phasing of expenditure; (vi) Milestones/Time lines (vii) Schedule of completion; (viii) Estimated completion cost; (ix) Other aspects.

9.5 Capital investment plan shall incorporate list of schemes in order of priority so as to enable the Commission to approve the schemes in that order and in case lesser amount of capital expenditure is to be approved then the schemes of lower priority could be disapproved

9.6 The generation company and licensee shall submit all information / data required by the Commission for approval of the capital investment plan.

9.7 In the normal course, the Commission shall not revisit the approved capital investment plan during the control period. However, during the mid-year performance review and true-up, the Commission shall monitor the year wise progress of the actual capital expenditure incurred by the generating company or the licensee vis-à-vis the approved capital expenditure and in case of significant difference between the actual expenditure viz-a-viz the approved expenditure, the Commission may true up the capital expenditure, subject to prudence check, as a part of annual true up exercise on or without an application to this effect by the generation company/licensee. The generating company and the licensee shall submit the scheme-wise actual capital expenditure incurred along with the mid-year performance review and true-up filing.

9.8 In case during the mid-year performance review, the actual cumulative capital expenditure incurred up to the current year starting from first year of the control period, is less by more than 15% of the approved cumulative capital expenditure, the Commission shall true-up the costs incidental to the actual capital expenditure in the current year and remaining years of the control period.

Provided that the actual capital expenditure incurred shall be only for the schemes as per the approved capital investment plan.

Provided that if the actual capital expenditure incurred is more than the approved capital expenditure, the Commission shall not allow any true-up of the cost incidental to such variations.

9.9 In case the capital expenditure is required due to Force Majeure events for works which have not been approved in the capital investment plan or for works that may have to be taken up to implement new schemes approved by the State/Central Govt., the generating company or the licensee shall submit an application containing all relevant information along with reasons justifying emergency nature of the proposed work seeking approval by the Commission. In the case of works or schemes, other than those required on account of Force Majeure events, the Commission shall consider to give approval only in those cases where the works / schemes are wholly / substantially financed by the State / Central Government or, in view of the Commission, shall benefit a large mass of consumers of the State. The generating company or the licensee may take up the work prior to the approval of the Commission only in case the delay in approval will cause undue loss and such emergency nature of the scheme has been certified by the Board of the Directors and intimated to the Commission:

Provided that the generating company or the licensee shall submit the requisite details, as required as per Regulation 9.1 above, within 10 days of the submission of the application for approval of emergency work;

Provided further that for the purpose of Regulation 9.7 and 9.8, such approved capital expenditure shall be treated as a part of actual capital expenditure incurred by the licensee as well as the capital expenditure approved by the Commission.

9.10 In case the capital expenditure incurred for approved schemes exceeds the amount as approved in the capital expenditure plan, the generating company or the transmission or the distribution licensee, as the case may be, shall file an application with the Commission at the end of control period for truing up the expenditure incurred over and above the approved amount. After prudence check, the Commission shall pass an appropriate order on case to case basis. The true-up application shall contain all the requisite information and supporting documents.

Provided that any additional capital expenditure incurred on account of time over run and / or on unapproved schemes not covered under Regulation 9.9 or unapproved changes in scope of approved schemes shall not be allowed by the Commission unless the generating company or the licensee, as the case may be, is able to give adequate justification for the same.

9.11 The generating company, transmission and the distribution licensees shall also provide a copy of their respective capital investment plans to each other at the time of filing of the same with the Commission so as to enable them to carry out planning and network augmentation / strengthening activities in a co-ordinated manner. The generating company, transmission and the distribution licensees shall, immediately after approval of their respective capital investment plans by the Commission, send copies of the same to each other. In addition to above the distribution licensee shall also provide a copy of its approved power procurement plan to the transmission licensee.

9.12 The generating company and transmission and distribution licensees shall, in general, extend all co-operation to each other by providing data /information required for carrying out planning and network augmentation / strengthening activities in a co-ordinated manner.

9.13 The Commission shall approve the capital investment plan within a period of 45 days from the date of its filing or submission of complete information, whichever is later.

9.14 For the purpose of first control period, the timeline for submission of business plan by the generating company and the licensees shall be as specified in Regulation 75 of these Regulations.

Provided that any capitalisation done by mere book entries / presentation in the financial statements in order to comply with any statute / rules etc. and not in accordance with the Capital Expenditure approved under these Regulations, shall not be allowed by the Commission. In such cases, the licensees / generating company shall be required to prepare memorandum account of any such capitalisation done and submit the same along with ARR / Tariff petition. No RoE, depreciation interest cost etc. shall be allowable on the same.

9.15 To enable faster adoption of Electric vehicles in the State, the Utilities i.e., HPGCL, HVPNL, DHBVN and UHBVNL shall endeavour to set up Public Charging Station (PCS) for charging Electric Vehicles near to their Sub-Stations or any other appropriate place.

10. BUSINESS PLAN

10.1 The generating company and the licensee, in respect of their respective businesses, shall file for approval of the Commission a business plan for a period covering the entire control period along with the MYT petition. The business plan shall provide the details for each year of the control period.

10.2 The business plan for a generating company shall be based on planned generation capacity growth and shall contain among other things the following (i) generation forecasts; (ii) future performance targets; (iii) proposed efficiency improvement measures; (iv) saving in operating costs; (v) Plan for reduction in per unit/per MW cost of generation (vi) financial statements (which include balance sheet, profit and loss statement and cash flow statement) - current and projected (at least for the control period duration) along with basis of projections; (vii) any other new measure to be initiated by the Generating Company e.g. IT initiatives, third party energy audit etc.

10.3 The business plan for transmission licensee shall be based on proposed generation capacity addition and future load forecasts of the state and should contain among other things the following: (i) future plans/ performance targets of the company including efficiency improvement measures proposed to be introduced (ii) plans for meeting reactive power requirements; (iii) plan for reduction in transmission losses; (iv) plan for improvement in quality of transmission service and reliability; (v) metering arrangements; (vi) Plan for reduction in per MW transmission cost, (vii) financial statements (which include balance sheet, profit and loss statement and cash flow statement)- current and projected (at least for the period of control period duration) along with basis of projections; (viii) any other new measure to be initiated by the Licensee e.g. IT initiatives etc.

10.4 The business plan for distribution licensee shall be based on sales forecast (MUs)/load growth and should contain among other things the following: (i) future plans/ performance targets of the company including efficiency improvement measures proposed to be introduced (ii) plan for reduction in distribution and non-technical losses;(iii) plan for improvement in quality of supply and reliability; (iv) metering arrangements; (v) plan for improvement in collection efficiency (vi) plan for improvement in consumer services/new consumer services (vii) Plan for reduction in O & M cost per MU of energy sales (viii) MIS; (ix) scheme for third party energy audit (x) plan for improvement in metering and billing; (xi) financial statements (which include balance sheet, profit and loss statement and cash flow statement)- current and projected (at least for the period of control period duration) along with basis of projections; (xii) any other new measure to be initiated by the Licensee(s) e.g. IT initiatives, development of distribution franchisee, periodical business satisfaction surveys etc.

10.5 In case the accumulated commercial losses of a generating company or the licensees have substantially eroded their respective paid up equity, the business plan shall also contain the proposal to progressively reduce the accumulated commercial losses indicating various measures, including re-capitalisation, proposed to be undertaken by the generation company/licensee to achieve turnaround of the company within a specified period.

10.6 The generation company and the licensee shall submit all information / data as required by the Commission for necessary approval of the business plan. The Commission shall scrutinize the business plan taking into consideration the additional information provided by the applicant, if any.

10.7 The Commission shall approve the business plan within a period of 45 days from the date of its filing or submission of complete information, whichever is later.

10.8 For the purpose of first control period, the timeline for submission of business plan by the generating company and the licensees shall be as specified in Regulation 75 of these Regulations.

11. MID-YEAR PERFORMANCE REVIEW AND TARIFF SETTING

11.1 The generating company and the licensee shall file an application for mid-year performance review, true-up of previous year and tariff for the ensuing year not less than 120 days before the close of each year of the control period, complete in all respects including the information in the formats prescribed as per Annexure - III.

11.2 The generating company and the licensees, within 7 (seven) days of filing of the application for mid-year performance review and true-up, shall publish for information of the public, the contents of the application filed with the Commission for mid-year performance review, true up of previous year and approval of tariff for the ensuing year in an abridged form in such manner as the Commission may direct and shall provide copies of the application and other documents filed with the Commission at a price not exceeding normal photocopying charges. The generating company and the licensees shall also host the application and other documents at their official websites.

11.3 The generating company and the licensee shall provide with the application for mid-year performance review the details of actual capital expenditure and details of any statutory levies and actual operational and cost data to enable the Commission to monitor the implementation of its order including comparison of actual performance with the approved forecasts (and reasons for deviations). In addition the generating company and the licensees shall also submit Annual Statement of Performance and Accounts of their respective businesses (indicating the plant-wise cost data, and unit-wise performance parameters in case of a generation company), a copy of latest audited accounts, analysis of detailed reasons for losses, if any, and any other information which the Commission may require to assess the reasons and extent of any variation in the performance from the approved forecast and the need for tariff resetting.

11.4 In their application for performance review, true-up and tariff for ensuing year, the generating company and the licensee shall submit information for the purpose of calculating expected expenditure and tariff along with information on financial and operational performance for the previous year(s). The information for the previous year should be based on audited accounts copies of which shall be supplied along with the application. In case audited accounts for the previous year are not available, audited accounts for the latest previous year should be filed along with unaudited accounts or provisional accounts for all the succeeding years. The application should also include the proposal for tariff revision, if any.

11.5 The scope of the mid-year performance review shall be a comparison of the performance of the generation company and the licensees for the relevant financial year with the approved forecast of ARR for their respective businesses and the performance targets specified by the Commission. Upon completion of the mid-year performance review and truing up as per Regulation 13, the Commission shall pass an order recording:

(a) The revised approved ARR for such financial year including approved modifications, if any;

(b) The approved aggregate gain or loss on account of controllable items and sharing of such gains or losses;

(c) Truing-up or pass through of uncontrollable items of ARR of previous year(s);

(d) Pass through of variations in controllable items due to force majeure events, if any.

(e) Pass through of variations in controllable items attributable to uncontrollable factors.

(f) Tariff applicable for the ensuing year.

11.6 The Commission shall review/consider, during the control period, the application made under this Regulation as also the application for truing up of the ARR of the previous year, as per provision of the Regulation 13, on the same principles as approved in the MYT order on the original application for determination of ARR and tariff. The review / true–up for FY 2018-19 shall, however, be done on the same principles as approved in the tariff order for FY 2018-19. Upon completion of such review/truing up, either approve the proposed modification with such changes as it deems appropriate, or reject the application for the reasons to be recorded in writing. The Commission shall afford opportunity of being heard to the affected party in case it considers rejecting the application.

12. INCENTIVE AND PENALTY FRAMEWORK (Sharing of gains & losses)

12.1 Various elements of the ARR of the generating company and the licensee will be subject to incentive and penalty framework as per the terms specified in this Regulation. The overall aim is to incentivize better performance and penalize poor performance, with the base level as per the norms / benchmarks specified by the Commission.

12.2 The elements of ARR of generating company and licensees to which incentive and penalty framework shall apply are as follows:

(a) Common for generating company and licensees

(i) **Operation & maintenance expenses**-Applicable when the actual expenses fall below or exceed the level specified by the Commission.

(ii) **Interest on new long-term loans**- Applicable when interest rate falls below or exceeds the level specified by the Commission.

(iii) **Restructuring of capital cost** - Applicable when there is a benefit from restructuring of capital cost.

(iv) **Interest on working capital**- Applicable when interest rate falls below or exceeds the level specified by the Commission

(vi) **Restructuring of loan portfolio**- Applicable when there is a net benefit from restructuring of loan portfolio

(b) Only for generation Company

(i) **Plant Availability Factor (PAF)-** Applicable when actual PAF falls below or exceeds the level specified by the Commission

(ii) **Station heat rate (SHR)-** Applicable when actual SHR falls below or exceeds the level specified by the Commission

(iii) **Auxiliary Energy Consumption (AUX)-** Applicable when actual AUX falls below or exceeds the level specified by the Commission

(iv) **Specific Fuel Oil Consumption (SFC)-** Applicable when actual SFC falls below or exceeds the level specified by the Commission

(v) **Transit loss of coal**- Applicable when actual transit loss falls below or exceeds the level specified by the Commission

Note: Until the Intra-State ABT Regulations are notified by the Commission, plant availability factor for the generating company shall mean plant load factor

(c) Only for Transmission Licensee

(i) **Availability**- Applicable when actual availability falls below or exceeds the level specified by the Commission. The incentive for actual availability above target availability shall be worked out as per the following formula:

I = ATC X (AA – TA) / TA

Where
I = Incentive
ATC = Annual transmission charges
AA = Annual availability achieved (actual)
TA = Normative target availability.

Note 1: The incentive mechanism for availability shall be applicable only when the transmission licensee submits detailed computation of the availability figures to the Commission and the Commission approves the same. The detailed computation will include all details of the input data, methods of recording the data (manual or through electronic modes), formula used for computation and all other details required to establish the current level of availability.

While reporting the level of availability to the Commission, the transmission licensee shall enclose a certificate from the SLDC validating the indicated level of availability.

Note 2: For all purposes the ‘normative target availability factor’ shall be considered for recovery of fixed charges. Any fall in the actual availability from the normative target availability shall result in pro-rata reduction of fixed charges.

(d) Only for Distribution Licensee

(i) **Distribution losses** - Applicable when actual distribution losses fall below or exceed the level specified by the Commission

(ii) **Collection efficiency-** Applicable when actual collection efficiency falls below or exceeds the level specified by the Commission

(iii) **Recovery of arrears** - Applicable when actual recovery of arrears of previous years falls below or exceeds the targets specified by the Commission

12.3 The gains / losses shall be computed item wise separately for each business. The computations shall be based on the data submitted by the generating company and the licensees in the application for mid-year performance review / true – up and audited annual accounts corresponding to the financial year.

12.4 **In case of gain**

The item wise gain shall be shared between the generating company or the licensee, as the case may be, and their respective beneficiaries in the ratio of 50:50. However, the sharing ratio of 50:50 may be revised to a maximum of 60:40 at the time of true-up during mid-year performance review / true-up. The manner of utilization of the additional 10% gain shall be specified by the Commission from time to time.

12.5 **In case of loss**

12.5.1 The item wise losses on account of controllable factors in case of a distribution licensee shall be dealt with in the following manner:

(a) The loss to the Distribution Licensee on account of Distribution losses, as may be admitted by the Commission after prudence check, shall be dealt with as under:

(i) One-third of the amount of such loss may be passed on as an additional charge in tariff over such period as may be specified in the Order of the Commission; and

(ii) The balance amount of loss shall be absorbed by the Distribution Licensee.

(b) The item wise losses on account of other controllable factors, unless otherwise specifically provided by the Commission, shall be borne by the distribution licensee.

12.5.2 The item wise losses on account of controllable factors in case of a generation company/transmission licensee, unless otherwise specifically provided by the Commission, shall be borne by the generation company/ transmission licensee.

13. TRUING-UP

13.1 Truing-up of the ARR of the previous year shall be carried out along with mid-year performance review of each year of the control period only when the audited accounts in respect of the year(s) under consideration is submitted along with the application. In case audited accounts pertaining to the year, of which truing-up is to be undertaken, are not available, the generating company or the licensee as the case may be, shall submit the provisional account duly approved by the Board of Directors of the company/licensee.

13.2 Truing-up of uncontrollable items shall be carried out at the end of each year of the control period through tariff resetting for the ensuing year and for controllable items shall be done only on account of force majeure conditions and for variations attributable to uncontrollable factors.

13.3 The Commission shall allow carrying costs for the trued–up amount (positive or negative) at the interest rates specified in these Regulations by adjusting the interest allowed on the working capital requirement for the relevant year of the control period.

Provided that no carrying cost shall be allowed on account of delay in filing for true-up due to unavailability of the audited accounts;

Provided further that if the Commission determines an over recovery during the true-up, funding cost for such trued-up amount shall be considered for the delayed period and adjusted accordingly as per provisions of this Regulation.

13.4 Over or under recoveries of trued-up amount in previous year(s) of the control period shall be allowed to be adjusted in the ensuing year of the control period by appropriate resetting of tariff. The unrecovered amount in the one control period shall be adjusted in the subsequent control period.

14. REVIEW AT THE END OF THE CONTROL PERIOD

14.1 At the end of the first control period, the Commission shall review the achievement of objectives and implementation of the principles of MYT laid down in these Regulations.

14.2 To meet the objectives of the Act, the National Electricity Policy and National Tariff Policy, the Commission may revise the principles of MYT for the second and subsequent control periods.

14.3 The end of the first control period shall be the beginning of the second control period. The generating company and the licensee shall follow the same procedure unless specified otherwise by the Commission. The Commission shall analyse the performance with respect to the targets set out at the beginning of the control period and shall determine the base values for the next control period on the basis of actual performance achieved, expected improvement and other relevant factors.

PART III - COMPONENTS OF ARR AND TARIFF FOR GENERATION,TRANSMISSION AND DISTRIBUTION BUSINESS

15. COMPONENTS OF TARIFF FOR GENERATION BUSINESS

15.1 The tariff for sale of electricity from a thermal generating plant shall comprise of two parts, namely,

a. Annual fixed charges (Capacity charges)
b. Variable charges (Energy Charges)

15.2 Both the components will be worked out in the manner provided in these Regulations.

15.3 The fixed cost of generating plant (thermal or hydro) shall include the following elements:

a) Return on equity
b) Interest and financing charges on loan capital
c) Interest on working capital
d) Depreciation
e) Operation and maintenance expenses
f) Cost of secondary fuel oil (only for thermal) [proposed to be included in VC in line with CERC]
g) Foreign exchange rate variation, if any
h) All statutory levies and taxes, if any, excluding taxes on income,

15.4 The Energy Charges (or variable charges) for a generating plant (thermal) shall comprise of only the primary fuel cost.

15.5 For the hydro plants i.e. Western Yamuna Canal Hydro project, Bhudkalan and Kakroi Hydro Plants, however, a single part tariff, based on a normative PLF and fixed cost worked out as per Regulation 34 hereinafter, shall be determined by the Commission.

16. COMPONENTS OF TARIFF FOR TRANSMISSION AND SLDC BUSINESS

16.1 The following charges shall be recovered for the use of Intra-state transmission system:

a) **Transmission tariff or network usage charges,** to reflect the cost of owning (Capital Investment), servicing and maintaining the transmission assets in order to transfer bulk power to and from different locations. The network usage charges or transmission tariff, payable by the beneficiaries of the transmission system shall be designed to recover the Aggregate Revenue Requirement of the transmission licensee approved by the Commission for each year of the control period;

b) **Reactive energy charges**, to reflect the voltage related drawl of reactive energy as provided in the Regulations hereinafter.

16.2 **SLDC charges,** to reflect the cost of operating the State Load Dispatch Centre (SLDC) including the cost of owning & maintaining it. These shall be levied as SLDC charges to the beneficiaries of the services of SLDC in accordance with the provisions of these Regulations

16.3 The ARRs of the transmission licensee for the transmission business and SLDC business comprise of only fixed costs which shall have the following components:

a) Return on equity (only for transmission business)
b) Interest and financing charges on Debt
c) Interest on working capital
d) Depreciation
e) Operation and maintenance expenses
f) Foreign exchange rate variation, if any
g) All statutory levies and taxes, if any, excluding taxes on income,

16.4 The transmission licensee, including the STU, shall base all the above information on the segregated accounts for its transmission business and for State Load Dispatch Centre (SLDC), a copy of which shall be submitted to the Commission along with the application for tariff determination/review.

16.5 **Connection charge**- A consumer or a person seeking connectivity to the transmission system for Open Access shall pay 'connection charge' to the transmission licensee as provided in HERC (Terms and condition for grant of connectivity and open access for intra-State transmission and distribution system) Regulations, 2012 as amended from time to time. Connection charges relate to cost of assets installed solely for the use by an individual user and cost of such assets shall not be considered for determination of transmission tariff.

17. COMPONENTS OF TARIFF FOR DISTRIBUTION AND RETAIL SUPPLY BUSINESS

17.1 For distribution licensees, the commission shall determine (i) retail supply tariff for their retail supply business i.e. sale of electricity to the consumers in their respective licensed areas which will be inclusive of wheeling charges and (ii) wheeling tariff for their wheeling business which shall be for the purpose of recovering wheeling charges from open access consumers falling in their respective licensed areas.

17.2 The ARRs of the distribution licensee for retail supply business and wheeling business will comprise the following elements:

ARR for Retail supply business	**ARR for Wheeling business**
A - Expenses a) Return on equity b) Interest and financing charges on loan capital c) Interest on working capital d) Depreciation e) Operation and maintenance expenses f) Foreign exchange rate variation, if any g) All statutory levies, and taxes including taxes on income, if any h) Bad and doubtful book debt allowed to be written off i) Cost of power purchase j) Transmission charges k) any other expenses not mentioned above. **Total expenses – A** **B - Income / receipts**: a) Non – tariff income including revenue from various surcharges b) Income from other business in accordance with HERC Regulations, 2007 as amended from time to time. c) Income from cross subsidy surcharge from open access consumers d) Income from additional surcharge from open access consumers e) Any grant, subvention, subsidy etc provided by the State Government Total Income / receipts – B **ARR for Retail supply business =** **(A – B)**	**A - Expenses** a) Return on equity b)Interest and financing charges on loan capital c) Interest on working capital d) Depreciation e) Operation and maintenance expenses f) Foreign exchange rate variation, if any g) All statutory levies and taxes, if any , excluding taxes on income, h) any other expenses not mentioned above **Total expenses – A** **B - Income / receipts**: a) Non – tariff income b) Income from other business, to the extent specified for wheeling tariff . c)) Income from wheeling of electricity from open access consumers Total Income / receipts – B

	ARR for Wheeling business = **(A – B)**

PART IV- GENERAL PRINCIPLES FOR DETERMINATION OF COMMON COMPONENTS OF ARR AND TARIFF FOR GENERATION, TRANSMISSION & DISTRIBUTION BUSINESS

18. CAPITAL COST

(1) The Capital cost as determined by the Commission after prudence check and subject to debt-equity ratio as per provisions of these Regulations, shall form the basis of determination of tariff for new power 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, in the event of the actual equity in excess of 30% of the funds deployed, by treating the excess equity as normative loan, or (ii) being equal to the actual amount of loan in the event of the actual equity less than 30% of the funds deployed;

(c) Increase in cost in contract packages as approved by the Commission;

(d) Interest during construction and incidental expenditure during construction as computed in accordance with these Regulation.

(e) capitalised Initial spares subject to the ceiling rates, as a percentage of the original Plant and Machinery cost as on the cut-off date, as specified below:-

	1. Coal-based generating plants:	2.50%

Generating Company	2. Gas Turbine / Combined Cycle generating plants	4.00%
	3. Hydro Generation Plants	1.50%
Transmission licensee	1. Transmission lines	0.75%
	2. Transmission substations	2.50%
	3. Series compensation devices and HVDC stations	3.50%
Distribution licensee	Distribution Business Projects	1.50%

Provided that:

(i) where the generating station has any transmission equipment forming part of the generation project, the ceiling norms for initial spares for such equipments shall be as per the ceiling norms specified for transmission system under these Regulations:

(ii) once the transmission project is commissioned, the cost of initial spares shall be restricted on the basis of plant and machinery cost corresponding to the transmission project at the time of truing up:

(iii) for the purpose of computing the cost of initial spares, plant and machinery cost shall be considered as on cut-off date excluding IDC, IEDC, Land Cost and cost of civil works. The generator/licensee shall submit the breakup of head wise IDC & IEDC in its tariff application.

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

(g) adjustment of revenue due to sale of infirm power in excess of fuel cost prior to the COD as specified under these Regulations; and

(h) adjustment of any revenue earned by using the assets before COD.

(3) The capital cost in case of a new hydro generating station 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 Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) project in the affected area.

(4) The capital cost with respect to thermal generating station, incurred or projected to be incurred on account of the Perform, Achieve and Trade (PAT) scheme or to achieve Environmental Norms / Statutory Norms of Government of India will be considered by the Commission on case to case basis and shall include:

(a) cost of plan proposed by developer in conformity with norms of PAT Scheme; and
(b) sharing of the benefits accrued on account of PAT Scheme.

(5) The following shall be excluded or removed from the capital cost of the existing and new project:
(a) The assets forming part of the project, but not in use;
(b) Decapitalisation of Asset;
(c) In case of hydro generating station 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 two-stage transparent process of bidding; and
(d) the proportionate cost of land which is being used for generating power from generating station based on renewable energy:

Provided that any grant received from the Central or State Government or any statutory body or authority for the execution of the project which does not carry any liability of repayment shall be excluded from the Capital Cost for the purpose of computation of interest on loan, return on equity and depreciation;

(6) Capital cost to be allowed by the Commission for the purpose of determination of tariff for respective businesses will be based on the capital investment plan prepared by the generating company or the licensee, as the case may be, and approved by the Commission prior to the filing of application for multiyear tariff by the generating company/licensees.

(7) Restructuring of capital cost in terms of relative share of equity and loan component, subject to provisions of Regulation 19, shall be permitted during the tariff period provided it does not affect tariff adversely. Any benefit from such restructuring shall be subjected to incentive / penalty framework as per Regulation 12.

(8) The amount of any contribution made by the consumers, open access consumers and Government subsidy towards works for connection to the distribution system or transmission system of the distribution /transmission licensee, shall be deducted from the original cost of the project for the purpose of calculating the amount under debt and equity under these Regulations.

18.1 Prudence Check of Capital Expenditure:

<u>Generating Company or the Transmission Licensee</u>

Where the capital cost considered in tariff by the Commission on the basis of projected additional capital expenditure exceeds the actual additional capital expenditure incurred on year to year basis by more than 10%, the generating company or the transmission licensee shall refund to the beneficiaries or the long term transmission customers as the case may be, the tariff recovered corresponding to the additional capital expenditure not incurred, as approved by the Commission, along with interest at 1.20 times of the bank rate as prevalent on 1st April of the respective year.

Where the capital cost considered in tariff by the Commission on the basis of projected additional capital expenditure falls short of the actual additional capital expenditure incurred by more than 10% on year to year basis, the generating company or the transmission licensee shall recover from the beneficiaries or the long term customers as the case may be, the shortfall in tariff corresponding to difference in additional capital expenditure, as approved by the Commission, along with interest at the bank rate as prevalent on 1st April of the respective year.

Distribution Licensee

Any excess tariff recovered on account of variation in projected capitalization in the tariff order vis-a-vis trued up capitalization by more than 10% during the year, shall be adjusted in the Revenue Gap/Surplus of the relevant year along with interest rate at 1.20 times of the bank rate prevalent on 1st April of respective year:

Provided that any excess tariff recovered on account of variation in projected capitalization in the tariff order vis-a-vis trued up capitalization due to reasons beyond the control of the Distribution Licensee i.e., delay in 'In-principle' approval of the schemes, road cutting permission from the concerned agencies etc., shall be adjusted in the Revenue Gap/Surplus of the relevant year along with interest rate equal to bank rate prevalent on 1st April of respective year.

Any shortfall in tariff recovered on account of variation in projected capitalization in the tariff order vis-a-vis trued up capitalization by more than 10% during the year, shall be adjusted in the Revenue Gap/Surplus of the relevant year along with interest rate at 0.80 times of the bank rate prevalent on 1st April of respective year.

The following principles shall be adopted for prudence check of capital cost of the existing or new projects:

(1) In case of the thermal generating station and the transmission system, prudence check of capital cost may be carried out taking into consideration the benchmark norms specified/to be specified by the Commission from time to time:

Provided that in cases where benchmark norms have not been specified, prudence check may include scrutiny of the capital expenditure, financing plan, interest during construction, incidental expenditure during construction for its reasonableness, use of efficient technology, cost over-run and time over-run, competitive bidding for procurement and such other matters as may be considered appropriate by the Commission for determination of tariff:

Provided further that in cases where benchmark norms have been specified, the generating company shall submit the reasons for exceeding the capital cost from benchmark norms to the satisfaction of the Commission for allowing cost above benchmark norms.

(2) The Commission may issue new guidelines or revise the existing guidelines for vetting of capital cost of hydro-electric projects by an independent agency or an expert and in that event the capital cost as vetted by such agency or expert may be considered by the Commission while determining the tariff for the hydro generating station.

(3) The Commission may issue new guidelines or revise the existing guidelines for scrutiny and approval of commissioning schedule of the hydro-electric projects in accordance with the tariff policy issued by the Central Government under section 3 of the Act from time to time which shall be considered for prudence check.

(4) Where the power purchase agreement entered into between the generating company and the beneficiaries provides for ceiling of actual capital expenditure, the Commission shall take into consideration such ceiling for determination of tariff for prudence check of capital cost.

Interest during construction (IDC), Incidental Expenditure during Construction (IEDC)

(A) Interest during Construction (IDC)

(1) Interest during construction shall be computed corresponding to the loan from the date of infusion of debt fund, and after considering the prudent phasing of funds upto SCOD.

(2) In case of additional costs on account of IDC due to delay in achieving the SCOD, the generating company or the licensee as the case may be, shall be required to furnish detailed justifications with supporting documents for such delay including prudent phasing of funds:

Provided that if the delay is not attributable to the generating company or the licensee as the case may be, and is due to uncontrollable factors as specified in these Regulations, IDC may be allowed after due prudence check:

Provided further that only IDC on actual loan may be allowed beyond the SCOD to the extent, the delay is found beyond the control of generating company , after due prudence and considering prudent phasing of funds.

(B) Incidental Expenditure during Construction (IEDC):

(1) Incidental expenditure during construction shall be computed from the zero date and after considering pre-operative expenses upto SCOD:

Provided that any revenue earned during construction period up to SCOD on account of interest on deposits or advances, or any other receipts may be considered for reduction in incidental expenditure during construction.

(2) In case of additional costs on account of IEDC due to delay in achieving the SCOD, the generating company or the transmission licensee as the case may be, shall be required to furnish detailed justification with supporting documents for such delay including the details of incidental expenditure during the period of delay and liquidated damages recovered or recoverable corresponding to the delay:

Provided that if the delay is not attributable to the generating company or the transmission licensee, as the case may be, and is due to uncontrollable factors, IEDC may be allowed after due prudence check:
Provided further that where the delay is attributable to an agency or contractor or supplier engaged by the generating company or the transmission licensee, the liquidated damages recovered from such agency or contractor or supplier shall be considered for computation of capital cost.

(3) In case the time over-run beyond SCOD is not admissible after due prudence, the increase of capital cost on account of cost variation corresponding to the period of time over run may be excluded from capitalization irrespective of price variation provisions in the contracts with supplier or contractor of the generating company.

Provided that following shall be considered as controllable and uncontrollable factors leading to cost escalation impacting Contract Prices, IDC and IEDC of the project :

(1) The “controllable factors” shall include but shall not be limited to the following:

(a) Variations in capital expenditure on account of time and/or cost over-runs on account of land acquisition issues;

(b) Efficiency in the implementation of the project not involving approved change in scope of such project, change in statutory levies or force majeure events; and
(c) Delay in execution of the project on account of contractor, supplier or agency of the generating company or transmission licensee.

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

(i) Force Majeure events; and
(ii) Change in law.

Provided that no additional impact of time overrun or cost over-run shall be allowed on account of non-commissioning of the generating station or associated transmission system by SCOD, as the same should be recovered through Implementation Agreement between the generating company and the transmission licensee:

Provided further that if the generating station is not commissioned on the SCOD of the associated transmission system, the generating company shall bear the IDC [and IEDC] or transmission charges if the transmission system is declared under commercial operation.

Provided also that if the transmission system is not commissioned on SCOD of the generating station, the transmission licensee shall arrange the evacuation from the generating station at its own arrangement and cost till the associated transmission system is commissioned.

18.2 **Additional capitalization**

18.2.1 The Commission may consider allowing, subject to prudence check, any additional capital expenditure incurred or projected to be incurred, after the commercial operation date of a project and up to the cut-off date, on the following provided the same was part of the original scope of work of the project:

(a) Deferred liabilities without any carrying cost;

(b) Works deferred for execution without any escalation;

(c) Procurement of initial capital spares in the original scope of work without any escalation, subject to ceiling specified above;

(d) Foreign exchange rate variation

(e) Liabilities to meet award of arbitration provided that it is not on account of any fault of the generation company or the licensee, as the case may be;

(f) Liabilities on account of compliance of the order or decree of a court;

(g Liabilities on account of change in law:

Provided that details of the works included in the original scope of work along with estimates of expenditure, un-discharged liabilities and works deferred for execution shall be submitted along with the application for determination of tariff after the date of commercial operation of the project;

18.2.2 The Commission may consider admitting, after prudence check, the capital expenditure of the following nature actually incurred after the cut-off date:

(a) Deferred liabilities relating to works / services within the original scope of work without any escalation;

(b) Liabilities to meet award of arbitration provided that it is not on account of any fault of the generation company or the licensee, as the case may be;

(c) Liabilities on account of compliance of the order or decree of a court;

(d) Liabilities on account of change in law;

(e) Any additional works / services which have become necessary for efficient and successful operation of the project, but not included in the original project cost;

18.2.3 Impact of additional capitalization in tariff revision within the approved project cost shall be considered by the Commission once during a particular financial year of the control period.

18.2.4 In case of a transmission licensee, any additional expenditure on items such as relays, control & instrumentation, computer system, power line carrier communication, DC batteries, replacement of switchyard equipment due to increase of fault level, emergency restoration system, insulators cleaning infrastructure, replacement of damaged equipment not covered by insurance and any other expenditure which has become necessary for successful and efficient operation of transmission system may be admitted by the commission subject to prudence check provided that such replacement has not been necessitated due to any fault attributable to the transmission licensee :

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

Note 1: Any expenditure admitted on account of committed liabilities within the original scope of work and the expenditure deferred on techno-economic grounds but falling within the original scope of work shall be serviced in the normative debt-equity specified in these Regulations;

Note 2: Any expenditure on replacement of old assets or renovation and modernization or life extension shall be considered after excluding the entire depreciated value or value of the scrap, whichever is higher, of the original assets from the original capital cost of the assets replaced;

Note 3: Any expenditure admitted by the Commission for determination of tariff on account of new works not in the original scope of work shall be serviced in the normative debt-equity specified in these Regulations.

18.2.5 Provided also that if any expenditure has been claimed under Renovation and Modernization (R&M), repairs and maintenance under O&M expenses and Compensation Allowance, same expenditure cannot be claimed under this Regulation.

18.2.6 In case of de-capitalization 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 decapitalization shall be deducted from the value of gross fixed asset and corresponding loan as well as equity shall be deducted from outstanding loan and the equity respectively in the year such de-capitalization takes place, duly taking into consideration the year in which it was capitalized.

18.2.7 The scrutiny of the project cost estimates by the Commission shall include the reasonableness of the capital cost, financing plan, interest during construction, use of efficient technology and such other matters for the purposes of determination of tariff.

18.3 Renovation and Modernization:

(1) The generating company or the transmission licensee, as the case may be, for meeting the expenditure on renovation and modernization (R&M) for the purpose of extension of life beyond the originally recognized useful life for the purpose of tariff of the generating station or a unit thereof or the transmission system or an element thereof, shall make an application 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.

(2) Where the generating company or the transmission licensee, as the case may be, makes an application for approval of its proposal for renovation and modernization, the approval shall be granted after due consideration of 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.

(3) In case of gas/ liquid fuel based open/ combined cycle thermal generating station, any expenditure which has become necessary for renovation of gas turbines/steam turbine after 25 years of operation from its COD and an expenditure necessary due to obsolescence or non-availability of spares for efficient operation of the stations shall be allowed :

Provided that any expenditure included in the 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 turbine shall be suitably deducted after due prudence from the R&M expenditure to be allowed.

(4) Any expenditure incurred or projected to be incurred and admitted by the Commission after prudence check based on the estimates of renovation and modernization expenditure and life extension, and after deducting the accumulated depreciation already recovered from the original project cost, shall form the basis for determination of tariff.

19. DEBT EQUITY RATIO

19.1 **Existing projects** - In case of the existing projects declared under commercial operation prior to 1st April 2020, debt-equity ratio as allowed by the Commission for determination of tariff for the period ending 31st March 2020 shall be considered.

19.2 **New projects** - For new projects commissioned or whose capacity is expanded on or after 1st April 2020:

(a) A Normative debt-equity ratio of 70:30 shall be considered for the purpose of determination of Tariff;

(b) In case the actual equity employed is in excess of 30%, the amount of equity for the purpose of tariff determination shall be limited to 30%, and the balance amount shall be considered as normative loan;

(c) In case the actual equity employed is less than 30%, then the actual debt-equity ratio shall be considered;

(d) The premium, if any, raised by the generating company or the licensee while issuing share capital and investment of internal accruals created out of free reserve, shall also be reckoned as paid up capital for the purpose of computing return on equity subject to the normative debt equity ratio of 70:30, provided such premium amount and internal accruals are actually utilized for meeting capital expenditure and form part of the approved financial package. For the purposes of computation of return, the portion of free reserves utilized for meeting the capital expenditure shall be considered from the date the asset created is productively deployed in the business.

19.3 **Renovation and modernization**

Any approved capital expenditure incurred by the generating company or the licensee on renovation and modernization of project (to be submitted as part of the capital investment plan) shall be considered to be financed at normative debt-equity ratio of 70:30. If the actual equity employed is less than 30%, then the actual debt equity ratio, subject to lower limit as per company law, shall be considered.

Provided that:

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

In case of Generating Station or a transmission system or distribution system, which has completed its useful life as on or after 1.4.2020, the accumulated depreciation as on the completion of the useful life less cumulative repayment of loan shall be utilized for reduction of the equity and depreciation admissible after the completion of useful life and the balance depreciation, if any, shall be first adjusted against the repayment of balance outstanding loan and thereafter shall be utilized for reduction of equity.

20. RETURN ON EQUITY

20.1 The rate of return on equity shall be decided by the Commission keeping in view the incentives and penalties and on the basis of overall performance subject to a ceiling of 14% provided that the ROE shall not be less than the net amount of incentive and penalty .

20.2 Return on equity shall be allowed on equity employed in assets in use considering the following and subject to Regulation 20.1 above:

i. Equity employed in accordance with Regulation 19.1 and 19.2 on assets (in use) commissioned prior to the beginning of the year; plus

II. 50% of equity capital portion of the allowable capital cost for the assets put to use during the year.

Provided that for the purpose of truing up, return on equity shall be allowed from the COD on pro-rata basis based on documentary evidence provided for the assets put to commercial operation during the year.

Provided further that assets funded by consumer contributions, capital subsidies/Govt. grants shall not form part of the capital base for the purpose of calculation of Return on Equity

20.3 Return on equity invested in work in progress shall be allowed from the actual date of commercial operation of the assets.

20.4 There shall be no Return on Equity for the equity component above 30%.

21. INTEREST ON LOAN CAPITAL

21.1 Existing loans

(i) Interest on loan capital shall be computed loan-wise for existing loans arrived in a manner specified in Regulation 19 and shall be as per the rates approved by the Commission.

(ii) The loan outstanding as on 1st April of each financial year shall be worked out as the gross loan in accordance with Regulation 19 by deducting the cumulative repayment as admitted by the Commission up to 31st March of previous financial year from the gross normative loan;

(iii) The rate of interest shall be the weighted average rate of interest on institutional loans calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the project. In case the weighted average rate is not available, the interest rate approved by the Commission in its earlier tariff order shall be allowed.

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

Provided further that if the generating plant/project does not have actual loan, then the weighted average rate of interest of the generating company/licensee as a whole shall be considered.

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

(v) The generating company and the licensee shall from time to time review their capital structure i.e. debt and equity and make every effort to restructure the loan portfolio as long as it results in net savings on interest. The costs associated with such re-financing shall be borne by the beneficiaries and the net savings (after deducting the cost of re-financing) shall be subjected to incentive / penalty framework as mentioned in the Regulation 12 which shall be dealt with at the time of mid-year performance review/true-up.

(vi) The changes to the loan terms and conditions shall be reflected from the date of such re-financing and benefit passed on to the beneficiaries;

(vii) In case of any dispute relating to re-financing of loan, any of the parties may approach the Commission with proper application along with all the relevant details. During the pendency of any dispute, the beneficiaries shall not withhold any payment on account of orders issued by the Commission.

(viii) In case any moratorium period on repayment of loan is availed of by the generating company or the licensee, depreciation provided for in the tariff during the years of moratorium shall be treated as repayment during those years and interest on loan capital shall be calculated accordingly.

Provided that the repayment for each year of the tariff period shall be deemed to be equal to the depreciation allowed for the corresponding year.

21.2 New loans (on or after 1st April 2020)

(i) Rate of interest on new loans i.e. on or after 01.04.2020 shall be equal to the marginal cost of funds-based lending rate (MCLR) of the SBI w.r.t. 1st April of the relevant financial year. They shall however, be required to submit due justification to the Commission for the terms and conditions of the loans raised by them.

Provided that interest and finance charges on works in progress shall be excluded and shall be considered as part of the capital cost;

Provided further that neither penal interest nor overdue interest shall be allowed for computation of Tariff

(ii) Any variation above or below the allowed interest rate shall be subject to the incentive and penalty framework specified in Regulation 12. The incentives on refinancing should be net of costs.

(iii) The amount of loan shall be arrived in the manner as specified in Regulation 19 and shall be based on the approved capital investment plan.

(iv) In case any moratorium period on repayment of loan is availed of by the generating company or the licensee, depreciation provided for in the tariff during the years of moratorium shall be treated as repayment during those years and interest on loan capital shall be calculated accordingly.

21.3 The interest computation shall exclude interest on loan amount, normative or otherwise, to the extent of capital cost funded by Consumer Contributions, Grants or Deposit Works carried out by Transmission Licensee or Distribution Licensee or Generating Company, as the case may be.

21.4 Interest shall be allowed on the amount held as security deposit held in cash from Transmission System Users, Distribution System Users and Retail consumers, at the Bank Rate as on 1st April of the financial year in which the petition is filed provided it is payable by the transmission/distribution licensee.

22. INTEREST ON WORKING CAPITAL

22.1 **Components of working capital**:

For the purpose of computing working capital the components mentioned in the table below shall be considered:

Generating company
I. **<u>Coal-based Thermal Generating Plants:</u>**
a) Cost of coal for 1 month corresponding to the normative availability (same for pit head);
b) Cost of secondary fuel oil for 1 month corresponding to the normative availability;
c) Normative O&M expenses for 1 (one) month;
d) Maintenance spares @ 10% of the O&M expenses;
e) Receivables equivalent to fixed and variables charges for 1 (one) month for sale of electricity calculated corresponding to normative availability.
II. **<u>Open-cycle / Combined Cycle Gas Turbine Thermal Generating Plants</u>:**
a) Fuel cost for 1 (one) month corresponding to the normative annual plant availability factor, duly considering mode of operation of the generating plant on gas fuel and liquid fuel;
b) Liquid fuel stock for ½ month corresponding to the normative annual plant availability factor, and in case of use of more than one liquid fuel, cost of main liquid fuel;
c) Maintenance spares @ 15% of normative operation and maintenance expenses;
d) Normative operation and maintenance expenses for one month.
e) Receivables equivalent to capacity charges and energy charges for 1 (one) month for sale of electricity calculated on normative plant availability factor, duly considering mode of operation of the generating plant on gas fuel and liquid fuel; and
III**. <u>Hydro power plants</u>**:
a) Normative operation and maintenance expenses for 1 (one) month

b) Maintenance spares @ 7.5% of normative operation and maintenance expenses;

c) Receivables equivalent to fixed cost for 1 (one) month

Transmission licensee

a) Normative O&M expenses for 1 (one) month;

b) Maintenance spares @ 15% of the O&M expenses;

c) Receivables equivalent to 1 (one) month of fixed cost calculated on normative target availability Less amount held as security deposits from Users except security deposits held in the form of Bank Guarantees

Provided that at the time of truing up for any year, the working capital requirement shall be re-calculated on the basis of the values of components of working capital approved by the Commission in the truing up

Distribution licensee

I. Wheeling of electricity:

a) Normative O&M expenses for wheeling business for 1 (one) month;

b) Maintenance spares for 1 (one) month based on annual requirement considered at 1% of GFA (wire business) at the end of the previous year;

c) Receivables equivalent to 2(two) months of wheeling charges.

less

Amount held as security deposits in cash from Distribution System Users :

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

II. Retail supply of electricity:

a) Normative O&M expenses for retail supply business for 1 (one) month;

b) Maintenance spares for 1 (one) month based on annual requirement considered at 1% of the GFA at the end of the previous year;

c) Uncollected revenue to be calculated as: Revenue billed for the relevant year * (1 – Normative Collection efficiency)

d) Receivables equivalent to 2 (two) months of billing less consumers' security / advance consumption deposit.

less

Amount held as security deposits in cash from retail supply consumers ;

	One-month equivalent of cost of power purchased, including the Transmission Charges and SLDC Charges, based on the annual power procurement plan : Provided that in case of power procurement from own Generating Stations of the Retail Supply Business, no amount shall be reduced from working capital requirement towards payables, to the extent of supply of power by the Generation Business to the Retail Supply Business, in the computation of working capital in accordance with these Regulations : Provided further that for the purpose of Truing-up for any year, the working capital requirement shall be re-computed on the basis of the values of components of working capital approved by the Commission in the Truing-up before sharing of gains and losses ;

22.2 **Rate of Interest**

Rate of interest on working capital shall be equal to the MCLR of the relevant financial year.

For the purpose of truing up, the actual weighted average Rate of Interest will be considered on the normative working capital by the commission.

23. DEPRECIATION

For the purpose of tariff determination, the depreciation shall be calculated in the following manner:-

(a) The value base of asset shall be the historical capital cost of the asset as admitted by the Commission. The historical capital cost shall include additional capitalization including foreign exchange rate variation, if any already allowed by the Commission up to 31st March of the relevant year.

(b) The residual value of the asset shall be considered as 10% and depreciation shall be allowed up to maximum of 90% of historical 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.

(c) Depreciation shall be calculated annually over the useful life of the asset at the rates specified in Appendix II up to 31st March of the 12th year from the date of commercial operation of the asset. From 1st April of 13th year from the commercial date of operation of the asset, the remaining depreciable value if any out of the 90% of the capital cost of the asset shall be equally spread over the balance useful life of the asset.

The deprecation rates given in Appendix-II will be applicable w.e.f. 1.04.2020 only. The depreciation, in case of existing assets, up to 31.03.2020 shall be considered as already allowed and shall not be re – visited. The deprecation rates as per Appendix-II for such assets shall be applicable w.e.f 1.04.2020 up to 12th year from the date of COD.

Provided that the rate provided in Appendix II, are the upper ceiling of the rate of depreciation to be provided up to 12th year from the date of COD and the developer shall have the option of indicating, while seeking approval for tariff, lower rate of depreciation, subject to the aforesaid ceiling.

(d) Land shall not be considered as a depreciable asset and cost shall be excluded from the capital cost while computing depreciable value of asset.

(e) Depreciation shall be chargeable from the first year of commercial operation. In case of commercial operation of the asset for part of the financial year, then the depreciation shall be charged on pro rata basis;

(f) Depreciation shall not be allowed on assets (or part of assets) funded by consumer contribution (i.e., any receipts from consumers that are not treated as revenue) and capital subsidies / grants. Provision for replacement of such assets shall be made in the capital investment plan.

24. FOREIGN EXCHANGE RATE VARIATION

24.1 The generating company or the licensee, as the case may be, may hedge foreign exchange exposure in respect of the interest on foreign currency loan and repayment of foreign loan acquired for the project in part or full at their discretion to safeguard their interest against extraordinary variations in the foreign exchange rates.

24.2 The generating company or the licensee shall recover the cost of hedging of foreign exchange rate variation corresponding to the normative foreign debt, in the relevant year on year-to-year basis as expense in the period in which it arises and no extra rupee liability corresponding to such foreign exchange rate variation shall be allowed against the hedged foreign currency debt;

24.3 To the extent the generating company or the licensee is not able to hedge the foreign exchange exposure, then to that extent, 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/licensees or their contractors.

24.4 The generating company/the licensee shall recover the cost of hedging and foreign exchange rate variations on year to year basis as income or expense in the period in which it arises

24.5 Any gain or loss on account of foreign exchange risk variation pertaining to the loan amount availed during the construction period shall form part of the capital cost.

25. INCOME TAX

Income tax, if any, on the income stream of the generating company or the licensee shall not be treated as an expense or a pass-through component in the tariff and shall be payable by the generating company or the licensees on their own.

26. INCOME FROM OTHER BUSINESS

The generation company and the licensees may engage in any other business for optimum utilization of their assets with prior intimation to the Commission. Such instances and transactions shall be governed in accordance with the Treatment of Income of Other Businesses of Transmission Licensee(s) and Distribution Licensee(s), Regulations, 2007 notified by the Commission, as amended from time to time.

Provided that the licensee shall follow a reasonable basis for allocation of all joint and common costs between the core/licensed business and the other business and shall submit the allocation statement as approved by the Board of Directors to the Commission along with his application for determination of tariff;

Provided further that where the sum total of the direct and indirect costs of such other business exceed the revenues from such other business or for any other reason, no amount shall be allowed to be added to the aggregate revenue requirement of the generation company or the licensees, as the case may be, on account of such other business.

27 A. PRIOR PERIOD EXPENSES

27.1 The utility may submit to the Commission the prior period expenses as a part of the filing for truing up;

27.2 The Commission may allow prior period expenses for uncontrollable cost items only as per the audited accounts during truing up.

27 B All Power utilities operating in the State of Haryana shall adhere to the following:

1. The financial statements along with reports of Statuary Auditors and C&AG shall be uploaded on utilities' website within 9 months of the closure of the relevant financial year.

2. All purchase of material and allotment of contracts exceeding Rs. 2.50 lakh in a year shall be done through e-tendering. The details of the same shall be uploaded on their website. Further, global tendering to be followed for contracts exceeding Rs. 5 Cr.

3. Cost-Benefit analysis shall be submitted to the Commission within 3 months of the closure of the relevant financial year indicating details of expenditure including salary and establishment cost incurred on the vigilance department and fraud detection/other activities undertaken during the financial year.

4. The power utilities shall not hire consultants over and above the sanctioned post of regular employees. Further, no employee shall be re-employed after retirement without the approval of Commission.

5. In order to promote Research & development in the State, the utilities shall depute its officials, who have more than 5 years of retirement and excellent track record, on foreign trainings. Separate accounting has to be maintained for this purpose and cost-benefit analysis to be submitted to the Commission within 3 months of the closure of the relevant financial year.

6. Post of Sports teams to be gradually abolished.

PART V- PRINCIPLES FOR DETERMINATION OF TARIFF AND NORMS OF OPERATION FOR GENERATION BUSINESS

28. NORMS OF OPERATION FOR THERMAL POWER STATIONS

(1) Normative Annual Plant Availability Factor (NAPAF)

(a) Existing Plants

Plant Name (Units)	MYT Period				
	2019-20 (%)	2020-21 (%)	2021-22 (%)	2022-23 (%)	2023-24 (%)
Panipat TPS (Unit 5)	20	20	20	20	20
Panipat TPS (Unit 6)	25	25	25	25	25
Panipat TPS (Unit 7)	85	85	85	85	85
Panipat TPS (Unit 8)	85	85	85	85	85
DCR TPS, Yamuna Nagar (Unit 1)	85	85	85	85	85
DCR TPS, Yamuna Nagar (Unit 2)	85	85	85	85	85
Rajiv Gandhi TPS, Khedar (Hisar) (Unit 1)	85	85	85	85	85
Rajiv Gandhi TPS, Khedar (Hisar) (Unit 2)	85	85	85	85	85

(b) New Plants Commissioned on or after 1st April 2020

Description	
Normative Annual Plant Availability Factor (NAPAF) in %	85

(2) Auxiliary Energy Consumption

(a) Existing Plants

Plant Name (Units)	MYT Period				
	2019-20 (%)	2020-21 (%)	2021-22 (%)	2022-23 (%)	2023-24 (%)
Panipat TPS (Units 5& 6)	9	9	9	9	9
Panipat TPS(Units 7 & 8)	8.50	8.50	8.50	8.50	8.50
DCR TPS, Yamuna Nagar (Units 1&2)	8.50	8.50	8.50	8.50	8.50
Rajiv Gandhi TPS, Khedar (Hisar) (Unit 1&2)	6	6	6	6	6

Provided that for thermal generating stations where tube type coal mill is used, the Auxiliary Energy Consumption norms shall be further increased by 0.8%.

(b) New Plants Commissioned on or after 1st April 2020

Description	Auxiliary Energy Consumption (%)
(i) Coal-based Generating Plants(with natural draft cooling tower or without cooling tower)*	
With Steam driven boiler feed pumps	6.00
With Electrically driven boiler feed pumps	8.50
(ii) Gas Turbine Generating Plants	
Combined Cycle	2.75
Open Cycle	1.00

For Coal-based generating stations with induced draft cooling towers, the norms shall be further increased by 0.5%.

Provided that recovery of Auxiliary Energy Consumption shall be computed in two parts:

a) **Fixed:** It shall form part of other expenses under Fixed Cost, at energy charge rate approved by the Commission in respective Tariff Order.

b) **Variable:** It shall form part of computation of energy charge rate of the respective month. The generating entities shall submit the details of the loads before the start of the Control Period which are operational even when the plant is shutdown. Such load of such Auxiliaries shall form part Fixed Cost and rest shall be recovered through Energy Charges.

The Generating Plants should endeavour to meet part load of their auxiliaries through Roof Top Solar, Small Hydro Plant having facility of Battery Energy Storage System.

(3) Station Heat Rate

(a) Existing Plants

Plant Name (Units)	MYT Period				
	2019-20 (kCal/kWh)	2020-21 (kCal/kWh)	2021-22 (kCal/kWh	2022-23 (kCal/kWh	2023-24 (kCal/kWh)
Panipat TPS (Units 5&6)	2550	2550	2550	2550	2550
Panipat TPS(Units 7 & 8)	2500	2500	2500	2500	2500
DCR TPS, Yamuna Nagar (Units 1&2)	2344	2344	2344	2344	2344
Rajiv Gandhi TPS, Khedar (Hisar) (Unit 1&2)	2387	2387	2387	2387	2387

Note: Station heat rate norms for Deen Bandhu Chhottu Ram TPS (Unit 1 and 2) and Rajiv Gandhi TPS (Unit 1 and 2) have been determined considering their design heat rate as 2201 kCal/kWh and 2241 kCal/kWh respectively and multiplying the same with a factor of 1.065.

(b) New Plants Commissioned on or after 1st April 2020

(i) Coal-based Thermal Generating Plants =1.065 X Design Heat Rate (kCal/kWh)

Where the Design Heat Rate of a unit means the unit heat rate guaranteed by the supplier at conditions of 100% MCR, zero percent make up, design coal and design cooling water temperature/back pressure:

Provided that the design heat rate shall not exceed the following maximum design unit heat rates depending upon the pressure and temperature ratings of the units:

Steam Pressure Rating (kg/ cm^2)	**150**	**170**	**170**	**247**	**247**
SHT/RHT (degree Celsius)	535/535	537/537	537/565	537/565	565/593
Type of Boiler Feed Pump	Electrical Driven	Turbine Driven	Turbine Driven	Turbine Driven	Turbine Driven
Maximum Turbine Cycle Heat Rate (kCal/kWh)	1955	1950	1935	1900	1850
Minimum Boiler Efficiency					
Sub-Bituminous Indian Coal	0.85	0.85	0.85	0.85	0.85
Bituminous Imported Coal	0.89	0.89	0.89	0.89	0.89
Maximum Design Unit Heat Rate (kCal/kWh)					
Sub-Bituminous Indian Coal	2300	2294	2276	2235	2176
Bituminous Imported Coal	2197	2191	2174	2135	2079

Provided further that in case pressure and temperature parameters of a unit are different from above ratings, the maximum design unit heat rate of the nearest class shall be taken;

Provided also that where unit heat rate has not been guaranteed but turbine cycle heat rate and boiler efficiency are guaranteed separately by the same supplier or different suppliers, the unit design heat rate shall be arrived at by using guaranteed turbine cycle heat rate and boiler efficiency.

Note: In respect of units where the boiler feed pumps are electrically operated, the maximum design unit heat rate shall be 40 kCal/kWh lower than the maximum design unit heat rate specified above with turbine driven Boiler Feed Pump.

(ii) Gas-based / Liquid fuel based thermal generating unit(s)/ block(s)

= 1.05 X Design Heat Rate of the unit/block for natural gas and RLNG as fuel (kCal/kWh)

= 1.071 X Design Heat Rate of the unit/block for liquid fuel (kCal/kWh)

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

(4) Secondary Fuel Oil Consumption (SFC)

(a) **Existing Plants**

Plant Name (Units)	**MYT Period**				
	2019-20 (ml/kWh)	**2020-21 (ml/kWh)**	**2021-22 (ml/kWh)**	**2022-23 (ml/kWh)**	**2023-24 (ml/kWh)**
Panipat TPS (Unit 5 &6)	0.5	0.5	0.5	0.5	0.5
Panipat TPS(Units 7 & 8)	0.5	0.5	0.5	0.5	0.5
DCR TPS, Yamuna Nagar (Units 1&2)	0.5	0.5	0.5	0.5	0.5
Rajiv Gandhi TPS, Khedar (Hisar) (Unit 1&2)	0.5	0.5	0.5	0.5	0.5

(b) **New Plants Commissioned on or after 1st April 2020**

Type	**Norms**
Coal-based Thermal Generating Plants	0.5 ml/kWh

(5) Operation and maintenance expenses:

The norms for O & M expenses (in Rs. Lac per MW) for the existing plants and the plants Commissioned on or after 1st April 2020 shall accordingly be as under:

Plant (Unit)	**MYT Period**				
	2019-20	**2020-21**	**2021-22**	**2022-23**	**2023-24**
Panipat TPS (Unit 5 & 6)	30.59	31.57	32.58	33.62	34.69
Panipat TPS (Unit 7)	30.59	31.57	32.58	33.62	34.69
Panipat TPS (Unit 8)	3..59	31.57	32.58	33.62	34.69

Plant (Unit)	MYT Period				
	2019-20	**2020-21**	**2021-22**	**2022-23**	**2023-24**
DCR TPS, Yamuna Nagar (Unit 1)	24.22	24.99	25.79	26.62	27.47
DCR TPS, Yamuna Nagar (Unit 2)	24.22	24.99	25.79	26.62	27.47
Rajiv Gandhi TPS (Unit 1)	17.39	17.94	18.52	19.11	19.72
Rajiv Gandhi TPS (Unit 2)	17.39	17.94	18.52	19.11	19.72

Provided that the above norms shall be multiplied by the following factors for additional units in respective unit sizes for the units whose COD occurs on or after 1st April 2020 in the same plant:

MW Class	Additional Unit No.	Multiplication factor
200/210/250 MW Class	Additional 6th units	0.90
	Additional 7th or more units	0.85
300/330/350 MW Class	Additional 4th and 5th Unit	0.90
	Additional 6th or more units	0.85
500 MW and above Class	Additional 3rd or 4th unit	0.90
	Additional 5th and above units	0.85

(i) Open Cycle /Combined Cycle Gas Turbine Generating Plants

(Rs. Lakhs / MW)

Year	Gas Turbine/Combined Cycle Generating Plants other than small gas turbine power generating plants	Small Gas Turbine Power Generating Plants
2019-20	16.24	34.38
2020-21	16.76	35.48
2021-22	17.30	36.62
2022-23	17.85	37.79
2023-24	18.42	39.00

(6) The norms for thermal power plants other than the existing plants listed above, whose tariff determination falls under the jurisdiction of the Commission, shall be same as for the new plants given in the sub clause (1) to (5) above corresponding to the capacity/type of the plant.

(7) For the generating units that undergo renovation and modernization: the Commission shall specify a separate set of norms of operation to be adopted during the renovation and modernization period and for the subsequent period. These norms shall be specified by the Commission on case to case basis as part of the renovation and modernization capital investment approval and shall prevail over the norms specified in these Regulations. The generation tariff shall be determined accordingly by the Commission for such generating units.

29. EXPENSES ON SECONDARY FUEL OIL FOR THERMAL POWER PROJECTS

(a) Expenses on secondary fuel oil (in Rs.) shall be computed corresponding to normative secondary fuel oil consumption (SFC) specified in this Regulation, in accordance with the following formula:

Expenses on secondary fuel oil (in Rs.) = $SFC \times LPSF_i \times NAPAF \times 24 \times NDY \times IC \times 10$

Where,

SFC	=	Normative specific fuel oil consumption in ml/kWh;
LPSFi	=	Weighted average landed price of secondary fuel in Rs. / ml considered initially;
NAPAF	=	Normative annual plant availability factor in percentage;
NDY	=	Number of days in a Year;
IC	=	Installed capacity in MW.

(b) Initially, the landed cost of secondary fuel oil shall be considered based on the weighted average price of secondary fuel oil during the three preceding months and in the absence of landed costs for the three preceding months, latest procurement price for the generating plant, before the start of the year shall be considered

(c) The secondary fuel oil expenses shall be subject to fuel price adjustment at the end of each year of tariff period as per following formula:

$$= SFC \times NAPAF \times 24 \times NDY \times IC \times 10 \times (LPSFy - LPSFi)$$

Where,

LPSFy = Weighted average landed price of secondary fuel oil for the Year in Rs./ml.

30 RECOVERY OF ANNUAL FIXED CHARGES (CAPACITY) CHARGES FOR THERMAL POWER PROJECTS

The fixed cost of a thermal generating station shall be computed on annual basis based on the norms specified under these regulations and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share or allocation in the capacity of the generating station. The capacity charge shall be recovered under two segments of the year, i.e. High Demand Season (period of three months) and Low Demand Season (period of remaining nine months), and within each season in two parts viz., Capacity Charge for Peak Hours of the month and Capacity Charge for Off-Peak Hours of the month as follows:

Capacity Charge for the Year (CCy) = Sum of Capacity Charge for three months of High Demand Season + Sum of Capacity Charge for nine months of Low Demand Season

(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 (CCm) = Capacity Charge for Peak Hours of the Month (CCp) + Capacity Charge for Off-Peak Hours of the Month (CCop)

Where,

High Demand Season:

CC_{p1}= $(0.20\ x\ \text{AFC})\ x\ \left(\frac{1}{12}\right)\ x\ \left(\frac{PAFMp}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\ \text{AFC})\ x\ \left(\frac{1}{12}\right)$

CC_{p2} = $\{(0.20\ x\text{AFC})x\left(\frac{1}{6}\right)x\left(\frac{PAFMp2}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{1}{6}\right)\} - CCp1$

CC_{p3}= $\{(0.20\ x\text{AFC})x\left(\frac{1}{4}\right)x\left(\frac{PAFMp}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{1}{4}\right)\} - (CCp1 + CCp2)]\}$

CC_{op1}= $\{(0.80\ x\text{AFC})x\left(\frac{1}{12}\right)x\left(\frac{PAFMop1}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\text{AFC})x\left(\frac{1}{12}\right)\}$

CC_{op2} = $\{(0.80\ x\text{AFC})x\left(\frac{1}{6}\right)x\left(\frac{PAFMop2}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\text{AFC})x\left(\frac{1}{6}\right)\} - CCop1$

CC_{op3} = $[(0.80\ x\text{AFC})x\left(\frac{1}{4}\right)x\left(\frac{PAFMop3}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\text{AFC})x\left(\frac{1}{4}\right)\} - (CCop1 + CCop2)$

Low Demand Season:

CC_{p1} = $\{(0.20\ x\text{AFC})x\left(\frac{1}{12}\right)x\left(\frac{PAFMp1}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{1}{12}\right)\}$

CC_{p2}= $\{(0.20\ x\text{AFC})x\left(\frac{1}{6}\right)x\left(\frac{PAFMp2}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{1}{6}\right)\} - CCp1$

CC_{p3}= $\{(0.20\ x\text{AFC})x\left(\frac{1}{4}\right)x\left(\frac{PAFMp3}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{1}{4}\right)\} - (CCp1 + CCp2)$

CC_{p4}= $\{(0.20\ x\text{AFC})x\left(\frac{1}{3}\right)x\left(\frac{PAFMp4}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\text{AFC})x\left(\frac{1}{3}\right)\} - (CCp1 + CCp2 + CCp3)$

$CC_{p5}=$ $\{(0.20\ x\mathrm{AFC})x\left(\frac{5}{12}\right)x\left(\frac{PAFMp5}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\mathrm{AFC})x\left(\frac{5}{12}\right)\}-$

$(CCp1+CCp2+CCp3+CCp4)$

$CC_{p6}=$ $\{(0.20\ x\mathrm{AFC})x\left(\frac{1}{2}\right)x\left(\frac{PAFMp}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\mathrm{AFC})x\left(\frac{1}{2}\right)\}-$

$(CCp1+CCp2+CCp3+CCp4+CCp5)$

$CC_{p7}=$ $\{(0.20\ x\mathrm{AFC})x\left(\frac{7}{12}\right)x\left(\frac{PAFMp7}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\mathrm{AFC})x\left(\frac{7}{12}\right)\}-$

$(CCp1+CCp2+CCp3+CCp4+CCp5+CCp6)$

$CC_{p8}=$ $\{(0.20\ x\mathrm{AFC})x\left(\frac{2}{3}\right)x\left(\frac{PAFMp8}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\mathrm{AFC})x\left(\frac{2}{3}\right)\}-$

$(CCp1+CCp2+CCp3+CCp4+CCp5+CCp6+CCp7)$

$CC_{p9}=$ $\{(0.20\ x\mathrm{AFC})x\left(\frac{3}{4}\right)x\left(\frac{PAFMp}{NAPAF}\right)$ subject to ceiling of $(0.20\ x\mathrm{AFC})x\left(\frac{3}{4}\right)\}-$

$(CCp1+CCp2+CCp3+CCp4+CCp5+CCp6+CCp7+CCp8)$

$CC_{op1}=$ $\{(0.80\ x\mathrm{AFC})x\left(\frac{1}{12}\right)x\left(\frac{PAFMop1}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\mathrm{AFC})x\left(\frac{1}{12}\right)\}$

$CC_{op2}=$ $\{(0.80\ x\mathrm{AFC})x\left(\frac{1}{6}\right)x\left(\frac{PAFMop2}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\mathrm{AFC})x\left(\frac{1}{6}\right)\}-$

$CCop1$

$CC_{op3}=$ $\{(0.80\ x\mathrm{AFC})x\left(\frac{1}{4}\right)x\left(\frac{PAFMop3}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\mathrm{AFC})x\left(\frac{1}{4}\right)\}-$

$(CCop1+CCop2)$

$CC_{op4}=$ $\{(0.80\ x\mathrm{AFC})x\left(\frac{1}{3}\right)x\left(\frac{PAFMop4}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\mathrm{AFC})x\left(\frac{1}{3}\right)\}-$

$(CCop1+CCop2+CCop3)$

$CC_{op5}=$ $\{(0.80\ x\mathrm{AFC})x\left(\frac{5}{12}\right)x\left(\frac{PAFMop5}{NAPAF}\right)$ subject to ceiling of $(0.80\ x\mathrm{AFC})x\left(\frac{5}{12}\right)\}-$

$(CCop1+CCop2+CCop3+CCop4)$

$$CC_{op6} = \{(0.80\ x\mathrm{AFC})x\left(\frac{1}{2}\right)x\left(\frac{PAFMop6}{NAPAF}\right) \text{ subject to ceiling of } (0.80\ x\mathrm{AFC})x\left(\frac{1}{2}\right)\} - (CCop1 + CCop2 + CCop3 + CCop4 + CCop5)$$

$$CC_{op7} = \{(0.80\ x\mathrm{AFC})x\left(\frac{7}{12}\right)x\left(\frac{PAFMop7}{NAPAF}\right) \text{ subject to ceiling of } (0.80\ x\mathrm{AFC})x\left(\frac{7}{12}\right)\} - (CCop1 + CCop2 + CCop3 + CCop4 + CCop5 + CCop6)$$

$$CC_{op8} = \{(0.80\ x\mathrm{AFC})x\left(\frac{2}{3}\right)x\left(\frac{PAFMo}{NAPAF}\right) \text{ subject to ceiling of } (0.80\ x\mathrm{AFC})x\left(\frac{2}{3}\right)\} - (CCop1 + CCop2 + CCop3 + CCop4 + CCop5 + CCop6 + CCop7)$$

$$CC_{op9} = \{(0.80\ x\mathrm{AFC})x\left(\frac{3}{4}\right)x\left(\frac{PAFMop9}{NAPAF}\right) \text{ subject to ceiling of } (0.80\ x\mathrm{AFC})x\left(\frac{3}{4}\right)\} - (CCop1 + CCop2 + CCop3 + CCop4 + CCop5 + CCop6 + CCop7 + CCop8)$$

Provided that in case of 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 loan only.

Where,

CCm= Capacity Charge for the Month;

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

CCop= Capacity Charge for the Off-Peak Hours of the Month;

CCpn= Capacity Charge for the Peak Hours of nth Month in a specific Season;

CCopn= Capacity Charge for the Off-Peak of nth Month in a specific Season;

AFC = Annual Fixed Cost;

PAFMpn = Plant Availability Factor achieved during Peak Hours upto the end of nth Month in a Season;

PAFMopn = Plant Availability Factor achieved during Off-Peak Hours upto the end of nth Month in a Season;

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 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 SLDC at least a week in advance. The High Demand Season (period of three months, consecutive or otherwise) and Low Demand Season (period of remaining nine months, consecutive or otherwise) in a region shall be declared by the SLDC, at least six months in advance:

Provided that SLDC, after duly considering the comments of the concerned stakeholders, shall declare Peak Hours and High Demand Season in such a way as to coincide with the majority of the Peak Hours and High Demand Season of the State to the maximum extent possible:

(4) Any under-recovery or over-recovery of Capacity Charge as a result of underachievement or over-achievement, vis-à-vis the NAPAF in Peak and Off-Peak Hours of a Season (High Demand Season or Low Demand Season, as the case may be) shall not be adjusted with under-achievement or over-achievement, vis-à-vis the NAPAF in Peak and Off-Peak Hours of the other Season:

Provided that within a Season, 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 in that Season:

Provided further that within a Season, 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 in that Season.

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

$$\text{PAFM} = 1000 \; x \sum_{i=1}^{N} \frac{DCi}{[N \; x \; IC \; x \; (100 - Aux)]} \%$$

Where,

AUX = Normative auxiliary energy consumption in percentage.

DCi = Average declared capacity (in ex-bus MW), for the ith 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.

(6) In addition to the capacity charge, an incentive shall be payable to a generating station or unit thereof @ 65 paise/ kWh for ex-bus scheduled energy during Peak Hours and @ 50 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 within each Season (High Demand Season or Low Demand Season, as the case may be), as specified in these Regulations.

Provided that in case HPGCL's power stations are backed down on the instructions of the DISCOMs and at the same time the Discoms are drawing power at a lower rate from some other sources i.e. generators, traders etc. or resorting to drawls under UI mechanism, the Discoms shall compensate HPGCL to the extent of fixed cost corresponding to loss of generation due to backing down. In such cases HPGCL shall have the right to sell power not scheduled by the Discoms to a third party provided any revenue earned on this account shall first be adjusted against the fixed cost to be recovered from the Discoms.

31 ENERGY CHARGES OR VARIABLE CHARGES FOR THERMAL POWER PROJECTS

(a) The Energy charges or variable charges shall cover the main fuel cost & secondary fuel oil and shall be payable for the total energy scheduled to be supplied to a beneficiary during the calendar month on ex-power plant basis, at the specified variable charge rate, with fuel price adjustment.

(b) The Energy charge for the month shall be worked out on the basis of ex-bus energy scheduled to be sent out from the generating plant in accordance with the following formula:

Energy charge or variable charge (Rs)

= Energy Charge Rate (Rs. / kWh) x Scheduled Energy (ex-bus) for the month (kWh)

Note: Until intra state ABT is implemented, 'scheduled energy' may be read as 'actual energy sent'.

(c) Energy charge rate (ECR) in Rs. per kWh on ex-power plant basis shall be determined to three decimal places in accordance with the following formula:

$$ECR = \{(SHR – SFC \times CVSF) \times LPPF / (CVPF + SFC \times LPSFi\} \times 100 /(100 – AUX)$$

Where

AUX = Normative auxiliary energy consumption in percentage;

CVPF = Gross calorific value of primary fuel as fired, in kCal per kg or per litre as applicable;

CVSF = Gross calorific value of secondary fuel in kCal per ml;

ECR = Energy charge rate in Rs. per kWh sent out;

SHR = Normative Station Heat rate in kCal per kWh;

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

LPPF = Weighted average landed price of primary fuel in Rs. per kg.

32 LANDED COST OF FUEL FOR THERMAL POWER PROJECTS

The landed cost of fuel for the month shall include price of fuel corresponding to the grade and quality of fuel inclusive of royalty, taxes and duties as applicable, transportation cost by rail/road or any other means, for the purpose of computation of energy charge and in case of coal, shall be arrived at after considering normative transit/moisture and handling losses as percentage of the quantity of coal dispatched by the coal supply company during the month as follows:

Non-pithead generating plants (upto 1000 KMs	:	Upto 0.8%
Non-pithead generating plants (above 1000 KMs	:	Upto 1.2%
Pit head generating plants	:	Upto 0.2%

33 PRIMARY FUEL PRICE ADJUSTMENT (FPA) FOR THERMAL POWER STATIONS

HPGCL shall claim FPA as per the details provided hereunder:-

Initially gross calorific value of coal shall be taken as per actual in the preceding financial year for which data is available. Any deviation shall be adjusted based on the gross calorific value of coal received and burnt and landed cost incurred by the generating company for procurement of coal on month to month basis. No separate petition shall be required to be filed with the Commission for fuel price adjustment. In case of any dispute related to primary fuel price adjustment, an appropriate application in accordance with Haryana Electricity Regulatory Commission (Conduct of Business) Regulations, 2004, as amended from time to time or any statutory re-enactment thereof, shall be made by the affected party before the Commission. For determining fuel price adjustment (FPA) amount the following formula shall be adopted:

$$FPA = \frac{10 * [SHRn - SFCn * Kos] * [\frac{Pcm}{Kcm} - \frac{Pcs}{Kcs}]}{(100 - ACn)}$$

Where,

FPA	=	Primary Fuel Price Adjustment in Paise/kWh;
SFC_n	=	Normative Specific Fuel Oil consumption in ml / kWh;
SHR_n	=	Normative Gross Station Heat Rate in kCal / kWh;
AC_n	=	Normative Auxiliary Energy Consumption in percentage;
K_{os}	=	Base value of GCV of fuel oil as taken for determination of base energy charge in tariff order in kCal/ml;
P_{cm}	=	Weighted average price of coal as per the invoices submitted for the month at the power station in Rs/MT;
K_{cm}	=	Weighted average GCV of coal fired at boiler front for the month in KCal/Kg;
P_{cs}	=	Base value of price of coal as taken for determination of base energy charge in tariff order in Rs/MT;
K_{cs}	=	Base value of GCV of coal as taken for determination of base energy charge in tariff order in KCal/Kg.

34 **Technical Minimum Schedule**

Technical Minimum Schedule for operation of Intra-State Coal based Generating Stations

1. The technical minimum for operation in respect of a unit or units of an intra-State Generating Station shall be 40% of MCR loading or installed capacity of the unit of at generating station.

2. The intra-State Generator may be directed by SLDC concerned to operate its unit(s) at or above the technical minimum but below the normative plant availability factor on account of grid security or due to the fewer schedules given by the beneficiaries.

3. Where the Generator, whose tariff is either determined or adopted by the Commission, is directed by the SLDC concerned to operate below normative plant availability factor but at or above technical minimum, the said Generator may be compensated depending on the average unit loading duly considering the forced outages, planned outages, PLF, generation at generator terminal, energy sent out ex-bus, number of start-stop, secondary fuel oil consumption and auxiliary energy consumption, in due consideration of actual and normative operating parameters of station heat rate, auxiliary energy consumption and secondary fuel oil consumption etc. on monthly basis duly supported by relevant data verified by SLDC.

Provided that:

(i) In case of coal / lignite based generating stations, following station heat rate degradation or actual heat rate, whichever is lower, shall be considered for the purpose of compensation:-

Sr.No	Unit loading as a % of	Increase in SHR	Increase in SHR

	Installed Capacity of the Unit	(for supercritical units) (%)	(for sub-critical units) (%)
1	85-100	Nil	Nil
2	75 - 84.99	1.25	2.25
3	65 - 74.99	2	4
4	55 - 64.99	3	6

(ii) In case of coal / lignite based generating stations, the following Auxiliary Energy Consumption degradation or actual, whichever is lower, shall be considered for the purpose of compensation:

Sr No.	Unit Loading (% of MCR)	% Degradation in AEC admissible
1	85 – 100	NIL
2	75 – 84.99	0.35
3	65 – 74.99	0.65
4	55 - 64.99	1.0

(iii) Where the scheduled generation falls below the technical minimum schedule, the SLDC concerned shall have the option to go for reserve shut down and in such cases, start-up fuel cost over and above seven (7) start / stop in a year shall be considered as additional compensation based on following norms or actual, Whichever is lower:

Unit Size (MW)	Oil Consumption per start up (Kl)		
	Hot	Warm	Cold
200/210/250 MW	20	30	50
500 MW	30	50	90
660 MW	40	60	110

(iv) In case of gas based intra-State Generating Station, compensation shall be decided based on the characteristic curve provided by the manufacturer and after prudence check of the actual operating parameters of Station Heat Rate, Auxiliary Energy Consumption, etc.

(v) Compensation for the Station Heat Rate and Auxiliary Energy Consumption shall be worked out in terms of energy charges.

(vi) The compensation so computed shall be borne by the entity who has caused the plant to be operated at schedule lower than corresponding to Normative Plant Availability Factor up to technical minimum based on the compensation mechanism finalized by the SLDC.

(vii) No compensation for Heat Rate degradation and Auxiliary Energy Consumption shall be admissible if the actual Heat Rate and / or actual Auxiliary Energy Consumption are lower than the normative Station Heat Rate and / or normative Auxiliary Energy Consumption applicable to the unit or the generating station.

(viii) There shall be reconciliation of the compensation at the end of the financial year in due consideration of actual weighted average operational parameters of station heat rate, auxiliary energy consumption and secondary oil consumption.

(ix) No compensation for Heat Rate degradation and Auxiliary Energy Consumption shall be admissible if the actual Heat Rate and / or actual Auxiliary Energy Consumption are lower than the normative station Heat Rate and / or normative Auxiliary Energy Consumption applicable to the unit or the generating station in a month or after annual reconciliation at the end of the year.

4. In case of a generating station whose tariff is neither determined nor adopted by the Commission, the concerned generating company shall have to factor the above provisions in the PPAs entered into by it for sale of power in order to claim compensations for operating at the technical minimum schedule.

5. The generating company shall keep the record of the emission levels from the plant due to part load operation and submit a report for each year to the Commission by 31st May of the year.

6. SLDC shall prepare a Detailed Operating Procedure in consultation with the generators and beneficiaries within 2 months' time and submit to the Commission for approval. The Detailed Operating Procedure shall contain the role of different agencies, data requirements, procedure for taking the units under reserve shut down and the methodology for identifying the generating stations or units thereof to be backed down upto the technical minimum in specific Grid conditions such as low system demand, Regulation of Power Supply and incidence of high renewables etc., based on merit order stacking.

7. The SLDC shall work out a mechanism for compensation for station heat rate and auxiliary energy consumption for low unit loading on monthly basis in terms of energy charges and compensation for secondary fuel oil consumption over and above the norm of 0.5 ml/kWh for additional start-ups in excess of 7 start-ups, in consultation with generators and beneficiaries including its sharing by the beneficiaries.

35 NORMS OF OPERATION AND DETERMINATION OF TARIFF FOR HYDRO POWER PLANTS

Norms of operation and determination of tariff for hydro power plants other than those covered under renewable energy sources, shall be as under:-

34.1 The tariff for sale of electricity from a Hydro Generating Station shall comprise of two parts, namely, the Capacity Charge and Energy Charge.

34.2 **Annual Fixed Charges:**

The Annual Fixed Charges shall comprise of the following elements:

(a) Depreciation;

(b) Interest and Finance Charges on Loan Capital;

(c) lnterest on Working Capital;

(d) Operation & Maintenance Expenses;

(e) Return on Equity;

(0 Special allowance in lieu of Renovation & Modernization, wherever applicable;

(g) SLDC Fees and Charges minus:

(h) Non-Tariff lncome:

Provided that Depreciation, interest and finance charges on Loan Capital, Interest on Working Capital and Return on Equity for Hydro Generating Stations shall be allowed in accordance with the provisions specified in these Regulations:

Provided further that prior period income/expenses shall be allowed by the Commission at the time of truing up based on audited accounts, on a case to case basis, subject to prudence check.

34.3 The norms of operation for existing hydro generating stations for recovery of Annual Fixed Charges shall be as under:-

Normative Annual Plant Availability Factor (%)	Auxiliary Consumption including Transformer Losses (%)
80%	1
80%	1

The following Normative Annual Plant Availability Factor CNAPAF) shall apply to other hydro generating stations for recovery of Annual Fixed Charges:

a) Storage and Pondage type plants with head variation between Full Reservoir Level (FRL) and Minimum Draw Down Level (MDDL) of up to 80%, and where plant availability is not affected by silt: 90%

b) In 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 basis of fixation of NAPAF.

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

d) Run-of-river type plants: NAPAF to be determined plant-wise, based on l0-day design energy data, moderated by past experience where available/relevant.

e) 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 Imitations.

The following Auxiliary Energy Consumption shall apply to other Hydro Stations

(a) Surface hydro generating stations:

i. With rotating exciters mounted on the generator shaft: 0.70%;

ii. With static excitation system: 1.00%;

(b) Underground hydro generating station:

i. With rotating exciters mounted on the generator shaft: 0.90%;

ii. With static excitation system: 1.20%.

34.4 Operation and Maintenance Expenses for Hydro Power Plant

a) The Operation and Maintenance expenses including insurance shall be derived on the basis of the average of the actual Operation and Maintenance expenses for the three (3) years ending March 31, 2018, subject to prudence check by the Commission.

b) The average of such operation and maintenance expenses shall be considered as operation and maintenance expenses for the financial year ended March 31, 2020 and shall be escalated at the escalation factor of 4% to arrive at operation and maintenance expenses for subsequent years of the control period. Alternatively, the Commission may peg O&M expenses for the first year of operation at 2% of the project cost admitted by the Commission (excluding cost of rehabilitation and resettlement works and any other cost that may be disallowed by the Commission including on account of delay in CoD).

(2) The O&M expenses for each subsequent year will be determined by escalating the base expenses determined above, at the escalation factor of 4%.

Capacity Charge and Energy Charge for Hydro Power Plants:

The Annual Fixed Charges of a Hydro Generating Station shall be computed on annual basis, based on the norms specified under these Regulations, and recovered on monthly basis under capacity charge (inclusive of incentive) and Energy Charge, which shall be payable by the beneficiaries in proportion to their respective share in the capacity of the generating station'

1. The capacity charge (inclusive of incentive) payable to a hydro generating station for a calendar month shall be as under:-

AFC x 0.5 x NDM /NDY x (PAFM/NAPAF) (in INR);

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.

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

PAFM = 10000x X ∑DCi / { N x IC x (100 - AUX) } %

i= 1

AUX = Normative auxiliary energy consumption in percentage;

DCi = Declared capacity (in ex-bus MW) for the is day of the month which the station can deliver for at least three (3) hours; as certified by the State Load Despatch Centre after the day is over.

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

N = Number of days in the month.

2. The Energy Charge shall be payable by every beneficiary for the total energy supplied to the beneficiary, excluding free energy for home state (FEHS), if any, during the calendar month on ex-power plant basis, at the computed Energy Charge rate.

Total Energy Charge payable to the Generating Company for a month shall be:

(Energy Charge Rate in Rs./kwh) x {Energy (ex-bus)} for the month in kWh x (100-FEHS)/100 .

3. 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:

$ECR = AFC \times 0.5 \times 10 / \{DE \times (100-AUX) \times (100-FEHS)\}$;

Where;

FEHS: Free energy for Home State.

DE = Annual Design Energy specified for the hydro generating station, in MWh, subject to the provision in Regulation below.

4. In case actual total energy generated by a Hydro Generating Station during a year is less than the Design Energy for reasons beyond the control of the Generating Company, the following treatment shall be applied on a rolling basis:

(i) in case the energy shortfall occurs within ten years from the date of commercial operation of a generating station, the ECR for the year following the year of energy shortfall shall be computed based on the formula specified in these Regulations with the modification that the DE for the year shall be considered as equal to the actual energy generated during the year of the shortfall, till the Energy Charge shortfall of the previous year has been made up, after which normal ECR shall be applicable;

(ii) in case the energy shortfall occurs after ten years from the date of commercial operation of a generating station, the following shall apply:-

Suppose the specified annual Design Energy (DE) for the station is DE MWh, and the actual energy generated during the relevant (first) and the following (second) financial years are Al and A2MWh, respectively, Al being less than DE, then the Design Energy to be considered in the formula in these Regulations for calculating the ECR for the third financial year shall be moderated as (A1 + A2 - DE) MWh, subject to a maximum of DE MWh and a minimum of Al MWh;

(iii)Actual energy generated (e.g., Al, A2) shall be arrived at by multiplying the net metered energy sent out from the station by 100 / (100 - AUX).

ln case the Energy Charge Rate (ECR) for a hydro generating station, as computed in Regulation above exceeds ninety 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 ninety paise per kWh only:

Provided that in a year following a year in which the total energy generated was less than the design energy for reasons beyond the control of the Generating Company, the Energy- Charge Rate shall be reduced to ninety paise per kWh after the energy charge shortfall of the previous year has been made up.

The State Load Despatch Centre shall finalize 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.

Capital Cost and Additional Capitalization

For the purpose of determination of tariff, the capital cost and additional capitalisation for Hydro Power Plants shall be allowed/approved in accordance with the provisions outlined under Regulation 18.

35 UNSCHEDULED INTERCHANGE CHARGES

(a) As and when intra state ABT is implemented, all variations between actual net injection and scheduled net injection for generating plant, and all variations between actual net drawl and schedule net drawl for beneficiaries shall be treated as their respective unscheduled interchanges (UI) and will be dealt with as per the intra-State ABT Regulations to be notified by the Commission.

(b) The profit and loss on account of unscheduled interchange shall be to the account of the generating company.

36 SCHEDULING

The methodology for scheduling and dispatch for the generating plant shall be as specified in the Haryana Grid Code/IEGC and the intra state ABT Regulations to be notified by the Commission as amended from time to time. Until the intra-State ABT Regulations are notified by the Commission CERC ABT Regulations would be applicable.

37 SLDC AND TRANSMISSION CHARGES

(a) SLDC and Transmission charges as determined by the Commission shall be considered as a part of expenditure, if payable by the generating company;

(b) SLDC and transmission charges paid for energy sold outside the state, if any, shall not be considered as expenses for determining generation tariff.

38 REACTIVE ENERGY CHARGES

A generating station shall inject/absorb the reactive energy into the grid as per the directions of State Load Despatch Centre. Such injection/absorption may be undertaken on the basis of machine capability and in accordance with the directions issued by SLDC as per the provisions of Haryana Grid Code as amended from time to time.

39 DEMONSTRATION OF DECLARED CAPACITY

(i) The generating company may be required to demonstrate the declared capacity of its generating plant as and when asked by the State Load Dispatch Centre or as requested by DISCOMs to SLDC. In the event of the generating company failing to demonstrate the declared capacity, the capacity charges due to the generating plant shall be reduced as a measure of penalty as provided below;

The quantum of penalty for the first mis-declaration in a financial year for any duration or block in a day shall be charged corresponding to two days of fixed charges. For the second mis-declaration the penalty shall be equivalent to fixed charges for four days and for subsequent mis-declarations in the financial year, the penalty shall be multiplied in the geometrical progression. Same process to be followed in the subsequent financial years;

(ii) The operating log books of the generating plant shall be available for review by the State Load Dispatch Centre. These books shall contain record of machine operation and maintenance.

(iii) The SLDC shall provide to the Commission any data/information in the context of demonstration of declared capacity by a generating company or in the context of any other issue concerning system operation/security as may be asked for by the Commission.

40 METERING AND ACCOUNTING

(i) Metering arrangement, including installation, testing and operation and maintenance of meters and collection, transportation and processing of data required for accounting of energy exchanges and average frequency on 15 minutes time block basis shall be provided by the State Load Dispatch Centre to the State Transmission Utility;

(ii) Processed data of the meters along with data relating to declared capacities and schedules etc shall be supplied by State Load Dispatch Centre to the State Transmission Utility;

(iii) For all purpose, the Standards for Metering and Accounting specified in the Haryana Grid Code Regulations 2009, intra-State ABT Regulations to be notified by the Commission and the Central Electricity Authority (Installation and Operation of Meters) Regulations 2006 notified by the CEA, shall be adopted and followed. Until the intra-State ABT Regulations are notified by the Commission, CERC ABT Regulations would be applicable.

41 BILLING AND PAYMENT

(i) Bills shall be raised for capacity charges, and energy charges on monthly basis by the generating company in accordance with these Regulations, and applicable payments shall be made by the beneficiaries directly to the generating company.

(ii) Payment of the capacity charges for a thermal generating plant shall be shared by the beneficiaries of the generating plant as per their percentage allocated share for the month (inclusive of any allocation out of the unallocated capacity) in the installed capacity of the generating plant.

42 REBATE FOR EARLY PAYMENT

In case of early payment of bills of capacity and energy charges the following schedule of rebate shall be followed:

Days from the date of receipt of bills of capacity charges, energy charges etc.	Rebate %
0-7	2.0
8-14	1.0
15-21	0.5
22-30	0.25

43 LATE PAYMENT SURCHARGE

In case the payment of any bill for charges payable under these Regulations is delayed by the beneficiary beyond a period of 30 days from the date of receipt of bill, a late payment surcharge at the rate of 0.04% per day shall be levied by the generating company and shall be payable by the beneficiaries.

44 SALE OF INFIRM POWER

(a) Supply of infirm power shall be accounted as Unscheduled Interchange (UI) and paid for from the regional or State UI pool account at the applicable frequency-linked UI rate.

(b) Any revenue earned by the generating company from sale of infirm power after accounting for the fuel expenses shall be applied for reduction in capital cost. Any loss on this account shall not be taken into consideration.

45 NON-TARIFF INCOME

(a) All incomes being incidental to electricity business and derived by the generating company from sources, including but not limited to profit derived from disposal of assets, rents, miscellaneous receipts from the beneficiaries, etc. shall constitute non-tariff Income of the generating company;

(b) The amount received by the generating company on account of non-tariff income shall be deducted from the aggregate revenue requirement for calculating the net revenue requirement of such licensee:

Provided that the generating company shall submit full details of his forecast of non-tariff income to the Commission in such form as may be stipulated by the Commission from time to time;

Provided that Late Payment Surcharge and Interest on Late Payment earned by the Generating Company shall not be considered under Non-tariff Income;

(c) The "non-tariff income" shall include but shall not be limited to the following:

i. Income from rent on land or buildings or other assets;
ii. Income from sale of land or other assets;
iii. Income from sale of scrap;
iv. Income from statutory investments;
v. Income from sale of Ash/rejected coal;
vi. Interest on advances to suppliers/contractors;
vii. Rental from staff quarters;
viii. Rental from contractors;
ix. Income from hire charges from contactors and others;
x. Deferred Income from grant, subsidy, etc., as per Annual Accounts;
xi. Income from advertisements;
xii. Excess found on physical verification;
xiii. Interest on investments, fixed and call deposits and bank balances;
xiv. Prior period income, etc.:

PART VI - PRINCIPLES FOR DETERMINATION OF TARIFF AND NORMS OF OPERATION FOR TRANSMISSION BUSINESS

45. NORMS OF OPERATION FOR TRANSMISSION LICENSEE

The norms of operation for transmission licensee shall be as under:

45.1 **Normative annual transmission system availability Factor (NATAF)**

Norm	MYT Period
AC System	99.2 (%)

The above-mentioned target availability will be subject to an incentive and penalty mechanism once the conditions specified in Regulation 12 are satisfied.

Provided also that for AC system, two trippings per year shall be allowed, and after two trippings in a year, additional 12 hours outage shall be considered in addition to the actual outage:

Provided also that in case of outage of a transmission element affecting evacuation of power from a generating station, outage hour shall be multiplied by a factor of 2.

45.2 **Auxiliary energy consumption in the substations**

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 will be included as part of the administrative and general expenses.

45.3 **Operation and maintenance expenses**

The actual audited Employee cost (excluding terminal liabilities) and A&G expenses for the financial year preceding the base year, subject to prudence check, shall be escalated at the escalation factor of 4% to arrive at the Employee cost (excluding terminal liabilities) and A&G expenses for the base year of the control period. The O&M expenses for the n^{th} year of the control period shall be approved based on the formula given below:

$$\mathbf{O\&M_n = (R\&M_n + EMP_n + A\&G_n)^* \ (1\text{-}X_n) + Terminal\ Liabilities}$$

Where,

- $R\&M_n$ – Repair and maintenance costs of the transmission licensee for the n^{th} year;
- EMPn – Employee costs of the transmission licensee for the nth year excluding terminal liabilities;
- A&Gn – Administrative and general costs of the transmission licensee for the nth year;

The above components shall be computed in the manner specified below:

(a) $R\&M_n = K*GFA*(INDX_n/ INDX_{n-1})$

Where,

- **'K'** is a constant (expressed in %) governing the relationship between O&M costs and Gross Fixed Assets (GFA) for the nth year. **The value of K will be 0.50% for the entire control period;**
- **GFA** is the average value of gross fixed assets for the nth year;
- **$INDX_n$** means the inflation factor for the nth year as defined herein after:

(b) EMP_n (excluding terminal liabilities) $+A\&G_n= (EMP_{n-1}+A\&G_{n-1})*(INDX_n/ INDX_{n-1})$

Where,

- INDXn – Inflation Factor to be used for indexing the employee cost and A&G cost. This will be a combination of the consumer price index (CPI) and the wholesale price index (WPI) for immediately preceding year and shall be calculated as under:
- $INDX_n = 0.55*CPI_n +0.45*WPI_n$

Note: As and when any material price index specific to power sector or a more relevant Index becomes available, the same shall replace the Index used for working out R&M cost.

Note: Source for CPI and WPI calculation as under:

Wholesale Price Index numbers as per Office of Economic Advisor of Government of India in the previous year;

Consumer Price Index for Industrial Workers (all India) as per Labour Bureau, Government of India in the previous year

(c) X_n is an efficiency factor for n^{th} year

X_n will be calculated by the Commission by analysing the change in the total operating expenditure i.e. expenditure before depreciation, interest and taxes (i)

Per unit of circuit km over last three years; and (ii) Per unit of transformation capacity over last three years.

The Value of X_n will be determined by the Commission in the MYT order for the control period. The transmission licensee will be required to submit the above data based on the actual for the last three years.

Note 1: For the purpose of estimation, the same $INDX_n$ value shall be used for all years of the control period. However, the Commission will consider the actual values in the $INDX_n$ at the end of each year during the mid-year performance review and true-up exercise and true-up the employee cost and A&G expenses on account of this variation.

Note 2: Any variation in employee cost and A&G cost on account of reasons beyond variation in $INDX_n$ will be subject to the incentive and penalty framework specified in these Regulations.

Note 3: Terminal liabilities will be approved as per actual expenditure incurred by the transmission licensee or as established through actuarial valuation

Note 4: O&M expenses made on account of extraordinary situations, if any, shall be submitted to Commission for its approval. Such expenses shall be filed separately and will not be subjected to incentive and penalty framework. The approved amount by the Commission shall be trued up in the mid-year performance review and true-up.

Note 5: Changes in the pay scales of employees necessitated on account of pay revision by Pay Commission or by the State Government orders shall be considered by the Commission for true-up during the mid-year performance review and true-up.

45.4 **Transmission losses (%)**

(a) The trajectory for, intra-state transmission loss, during the control period shall be as under:

FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24
2.15	2.10	2.05	2.02	2.0

(b) The losses shall be borne by the beneficiaries in kind. The SLDC shall reduce the demand scheduled by the beneficiaries during each time block by the 12 months rolling transmission losses (the said period will be the 12 months period proceeding the relevant month by 3 months). The SLDC shall post the rolling 12 months losses regularly on its website. The SLDC, however, shall develop necessary software for working out rolling 52-week losses and reduce the scheduled demand accordingly thereafter.

(c) If the actual annual transmission losses (%) exceed the benchmark value (%) approved by the Commission, the licensee(s) shall be penalized in the following manner:

Percentage increase above the Loss level specified by the Commission	**Penalty**
Upto 5%	No Penalty
More than 5% and upto 10%	Reduction in return on equity in Rs crore by 0.5 %
More than 10% and upto 15%	Reduction in return on equity in Rs crore by 1 %
More than 15%	Reduction in return on equity in Rs Crore by 1% + 0.5% for every increase of 5% or part thereof above 15%

Example: In case the specified transmission loss level is 3%, then an increase of 0.15 in the loss level will amount to 5% increase. Similarly, an increase of 0.30 and 0.45 in the loss level will amount to 10% and 15% increase in the loss level respectively.

Provided, further that the intra-State transmission loss, in excess of the benchmark specified in these Regulations shall not be passed on to the beneficiaries / electricity consumers.

46 NON-TARIFF INCOME

(a) All incomes being incidental to electricity business and derived by the licensee from sources, including but not limited to profit derived from disposal of assets, rents, miscellaneous receipts from the beneficiaries, etc. shall constitute non-tariff Income of the licensee;

(b) The amount received by the licensee on account of non-tariff income shall be deducted from the aggregate revenue requirement for calculating the net revenue requirement of such licensee:

Provided that the transmission licensee shall submit full details of his forecast of non-tariff income to the Commission in such form as may be stipulated by the Commission from time to time;

Provided that Late Payment Surcharge and Interest on Late Payment earned by the the Licensee shall not be considered under Non-tariff Income;

(c) The "non-tariff income" shall include but shall not be limited to the following:

i. Income from rent on land or buildings or other assets;
ii. Income from sale of land or other assets;
iii. Income from sale of scrap;
iv. Income from statutory investments;
v. Income from interest on contingency reserve investment;
vi. Interest on advances to suppliers/contractors;
vii. Rental from staff quarters;
viii. Rental from contractors;
ix. Income from hire charges from contactors and others;
x. Income from advertisements, etc.;
xi. Miscellaneous receipts like parallel operation charges;
xii. Deferred Income from grant, subsidy, etc., as per Annual Accounts;
xiii. Excess found on physical verification;
xiv. Interest on investments, fixed and call deposits and bank balances;
xv. Prior period income, etc

47 INCOME FROM SHORT TERM OPEN ACCESS CONSUMERS

(a) The charges payable by the short-term open access consumers shall be as specified in the intra-State open access Regulations notified by the Commission and as amended from time to time;

(b) 25% of the charges collected from the short-term open access consumers on account of application money and transmission charges shall be retained by the transmission licensee and the balance 75% shall be considered as non-tariff income and adjusted towards reduction in the transmission service charges payable by the long term and medium-term users.

48 REACTIVE ENERGY CHARGES

(a) The reactive energy charges shall be as provided in the Haryana Grid Code as amended from time to time.

(b) Reactive energy charge shall be payable and shared as per Regulation 5.5.1 of Haryana Grid Code (HGC) Regulation, 2009 as amended from time to time;

(c) Reactive energy account shall be maintained and operated as per the intra-State ABT Regulations to be notified by the Commission and as amended from time to time. Until the intra-State ABT Regulations are notified by the Commission, CERC ABT Regulations shall be applicable;

(d) The reactive energy charges from embedded open access consumers shall be recovered by the distribution licensee by apportioning the total reactive energy drawn during the month in the ratio of energy drawn through open access and the energy drawn from the distribution licensee. The reactive energy charges shall be recovered for the apportioned reactive energy corresponding to energy drawn through open access at the applicable rate.

49 ANNUAL TRANSMISSION CHARGES

(a) The total annual transmission charges of a transmission licensee shall be equal to total annual expenses and return on equity as allowed as per these Regulations less non-tariff income and 50% of the revenue generated from other business in line with HERC Regulations, 2007 for other income as amended from time to time;

(b) The transmission licensee shall be entitled to recover its annual transmission charges (ATC) from the beneficiaries.

50 RECOVERY OF ANNUAL TRANSMISSION CHARGES

(a) Transmission licensee shall recover the transmission charges at the normative annual transmission system availability factor specified for it by the Commission.

(b) Payment of transmission charges

Annual transmission charges shall be fully recoverable at the specified level of target availability. Payment of transmission charges below the specified target availability shall be on pro-rata basis. The transmission licensee may recover its annual transmission charges by way of a fixed charge based on transformation capacity. The transmission charges shall be calculated on a monthly basis. In case of more than one beneficiaries of the transmission system, including the distribution licensees and long term and medium term open access consumers (but subject to any exclusion of any other open access consumers as per the open access Regulation notified by the Commission), the monthly transmission charges leviable on each beneficiary shall be computed as per the following formula.

$$\text{Monthly Transmission Charges} = \frac{ATC}{12} \times \frac{CA}{CS}$$

Where,

ATC = Annual Transmission Charges payable by all the beneficiaries after deducting any benefits to be considered as decided by the Commission;

CA = Transformation Capacity (MVA) allocated to each beneficiary.

CS = Sum of Transformation Capacity (MVA) allocated to all beneficiaries.

Note: Where allocated Transformation Capacity (MVA) of a beneficiary is not available, the contracted capacity in MW shall be converted in MVA at a power factor of 0.90 and the same shall be considered for computation of monthly transmission charges payable by the beneficiaries.

Provided that monthly Transmission tariff shall also be shared by a Generation Company (including Renewable Energy Generators which opt for third party sale) if power from such Generating Company is sold to a consumer outside the State of Haryana to the extent of capacity contracted outside the state.

Provided further that the Long Term and Medium-Term beneficiaries of the Transmission System shall pay no other charges for the use of Transmission Network of STU.

Provided also that the transmission charges shall be payable by the short-term open access consumers for the scheduled energy drawl at per kWh rate as worked out by dividing the annual transmission charges by the total volume of energy transmitted by the transmission licensee during the previous year.

51. SHARING OF CHARGES FOR INTRA-STATE TRANSMISSION NETWORK IN CASE OF MULTIPLE TRANSMISSION LICENSEES

51.1 **Determination of Monthly Transmission Tariff (MTT)**

51.1.1 The aggregate of the yearly revenue requirement for all Transmission Licensees, less the deductions, as approved by the Commission for a financial year, shall form the "Total Transmission Cost" (TTC) of the Intra State transmission system, to be recovered from the Long-term and Medium term Transmission System Users (TSUs) for that financial year, in accordance with the following formula:

$$TTC = \sum_{i=1}^{n} (ARR_i - NT_i - O_i) - STR$$

Where,

TTC = Total Transmission Cost for the financial year

n = Number of Transmission Licensee(s)

ARR_i = Aggregate Revenue Requirement approved by the Commission for i^{th} Transmission Licensee for the financial year

NT_i = Approved level of non-tariff income for i^{th} Transmission Licensee for the financial year

O_i = Approved level of income from other business of the i^{th} Transmission Licensee for the financial year

STR = Revenue from short-term open access charges recovered and not allowed to be retained during previous financial year.

Provided that the revenue from short-term open access charges for each year of Control Period shall be taken to be same as that prevalent during the base year. However, the adjustments due to variation in actual revenue from short-term open access charges shall be undertaken during annual truing up:

Provided further that ARR of the Transmission Licensee, in case of transmission projects selected through competitive bidding, shall be the Transmission Service Charge (TSC) for relevant year as per the Transmission Service Agreement (TSA) approved and adopted by the Commission in accordance with Section 63 of the Act.

51.1.2 The Total Transmission Cost (TTC) as determined by the Commission as per Regulation 51.1.1 above, shall be shared by all long-term and medium-term open access consumers on monthly basis (including existing Distribution Licensees) in the same manner as provided for in Regulation 50 for sharing of annual transmission charges.

52 RECOVERY OF CHARGES BY SLDC FROM BENEFICIARIES

“The annual charges of SLDC determined as per Regulations 6 and 16, shall be recovered as a single composite charge from the beneficiaries as under:

(1) Intra-State transmission licensee	8% of Annual SLDC Charges
(2) Generating stations and sellers	46% of Annual SLDC Charges
(3) Distribution licensee and buyers	46% of Annual SLDC Charges

(i) The SLDC charges shall be levied by the Transmission licensees / STU, also designated as the SLDC, on the basis of weighted average of the lines (Ckt. km) owned by the Intra State Transmission Licensee(s) as on the last day of the month prior to billing of the month.

Ckt. Km 400 kV MF 4 product
Ckt. Km 220 kV MF 2.2 product
Ckt. Km 132 kV MF 1.32 product
Ckt. Km 66 kV MF 0.66 product

____

Total __XXX___

Therefore, the SLDC charges for transmission licensee
=
8% x (annual SLDC charges X weighted Ckt Km of concerned transmission licensee) / total weighted Ckt. Km of all transmission licensees

(ii) The SLDC charges from the generating companies and sellers (which Exclude short term open access consumers) shall be collected in proportion to their installed capacity /contracted capacity as on the last day of the month prior to billing of the month.

(iii) The SLDC charges from distribution licensees and buyers (which exclude short term open access consumers) shall be collected in proportion to the sum of their allocated transmission capacity in MVA as on the last day of the month prior to billing of the month.

(iv) SLDC charges shall be collected on monthly basis.
(v)Any deviation in the value of annual SLDC charges determined and collected from the beneficiaries shall be trued up during the mid-year performance review and true-up.

(vi) For the purpose of recovery of SLDC charges from the entity which has entered into a long term open access / Medium Term open access agreement with STU, shall be considered under the category in which it has applied/signed the Long Term/Medium Term Open Access agreement i.e. generator/supplier or distribution licensee/buyer".

53 RECOVERY OF SLDC CHARGES FROM SHORT TERM OPEN ACCESS CONSUMERS

The short-term open access consumers shall pay composite SLDC charges as provided in HERC (Terms and conditions for grant of connectivity and open access for intra–State transmission and distribution system), Regulations, 2012 as amended from time to time. The total receipt of SLDC charges from short term open access consumers shall be utilised to reduce the SLDC charges payable by the beneficiaries.

54. BILLING AND PAYMENT OF CHARGES

54.1 The State Transmission Utility shall raise bills for SLDC and transmission charges payable by the beneficiaries on a monthly basis. The STU shall raise bills for UI charges on weekly basis as and when intra state ABT is implemented. UI accounting procedures shall be governed by intra-state ABT Regulations to be notified by the Commission as amended from time to time.

54.2 Rebate for early payment

In case of early payment of bills of transmission and other charges the rebate as under shall be admissible:

Days from the date of receipt of bills of transmission charges	**Rebate (%)**
0-7	2
8-14	1
15-21	0.5
22-30	0.25

54.3 Late payment surcharge

In case the payment of bills of transmission and other charges by the beneficiary is delayed beyond a period of 30 days from the date of receipt of bill, a late payment surcharge of 0.04% per day shall be payable by the beneficiary.

55. Quality of Supply

The Commission shall monitor the following Quality of Transmission parameters during the Control Period.

a) Transmission System Availability

b) Transformer Failure across various capacities which represents the number of transformer failures as a percentage of the total number of transformers in that specified capacity within the Transmission System over a specified period of time.

c) System Reliability

The Transmission Licensee in its Business Plan filings shall submit and propose the trajectory for the achievement of quality targets including reduction in the frequency of interruptions. The Commission shall specify the targets for each parameter. The Transmission Licensee shall submit its performance on each parameter in the form and manner specified by the Commission. In the case of frequency of interruptions being high the same will have bearing on the level of incentive allowed for availability.

The Transmission Licensee shall achieve redundancy in their system and move towards N-1 criteria for their system planning. Also, Transmission Licensee shall focus in setting up 220/33 kV S/s for ultimate usage of the end consumer and shall avoid setting up new 132kV S/s or such voltage levels S/s whose consumers are not in place.

56. Safety Standards

The Transmission Licensee shall develop a Safety Manual and follow procedure to maintain the safety standards during construction, operation, etc. in line with the provisions of CEA (Measures relating to Safety and Electric Supply) Regulations, 2010 as amended from time to time.

PART VII - PRINCIPLES FOR DETERMINATION OF TARIFF AND NORMS OF OPERATION FOR DISTRIBUTION BUSINESS

57. NORMS OF OPERATION FOR DISTRIBUTION LICENSEE

The norms of operation for distribution licensee shall be as under:

57.1 Distribution loss

(a) The distribution loss shall be equal to the difference between the energy injected into the distribution system (X) and the sum of energy sold to all its consumers (Y);

(b) Energy sold shall be the sum of metered sales and assessed unmetered sales, if any, based on approved methodology/ norms. The percentage distribution loss shall be as follows:

Percentage distribution loss = ((X- Y)/X) x 100

(c) The distribution licensee shall file the loss trajectory in the business plan commensurate with the capital investment plan. The Commission after verification and evaluation of the same shall approve the loss trajectory for each year of the control period;

(d) The distribution loss level will be linked to a normative load factor for unmetered agriculture consumers. The distribution licensee shall establish consumption of unmetered agriculture consumers through a representative and reliable energy audit/sample tube well metering/sample DT metering/ meter readings of the 11 kV segregated AP feeders and submit requisite data for consideration of the Commission.

(e) The Distribution Loss trajectory for the Control Period shall be as follows:

Distribution Licensee	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24
UHBVNL	14.14%	13.14%	12.14%	11.74%	11.24%
DHBVN	12.63%	12.14%	11.74%	11.24%	11.00%

(f) In the absence of requisite data in respect of such energy audit / sample surveys / sample DT metering/ meter readings of segregated 11kV AP feeders, the Commission shall not accept the claim of the distribution licensee and may proceed to fix the loss levels and the load factor for unmetered agriculture consumption on the basis of the information available with it;

(g) The distribution licensee shall furnish within a period of six months from the date of notification of these Regulations, computation of supply voltage - wise and consumer category wise distribution and AT&C losses;

(h) Any overachievement and underachievement of the loss trajectory shall be subject to incentive and penalty framework specified in Regulation 12. The distribution licensee(s) shall provide a statement to this effect in the mid-year performance review and true-up.

Provided that the financial impact on account of over or under achievement of Distribution Loss target shall be computed as under:

$$\text{Incentive or (Penalty)} = \text{Q1} * (\text{L1} - \text{L2}) * \text{P} * 10^6$$

where,

Q1 = Actual quantum of Energy purchased at Distribution periphery in MU;

L1 = Distribution Loss Target in %;

P = Trued up Average Power Purchase Cost (APPC) per unit at Distribution periphery in Rs./kWh;

$\text{L2 (Actual Distribution Loss in \%)} = \left[1 - \frac{Q2}{Q1}\right] * 100;$

Q2 = Actual quantum of Energy Billed in MU.

57.2 Collection Efficiency

The norms for Collection Efficiency for the distribution licensee(s) shall be 99.50% for every year of this Control Period.

Besides the Collection Efficiency, the Commission shall also monitor the recovery of arrears of previous years for which the Commission shall prescribe the targets and shall accordingly assess the performance of the licensee with regard to recovery of arrears.

Any over achievement or under achievement in respect of Collection Efficiency and recovery of arrears shall be subject to incentive and penalty framework as specified in Regulation 12.

57.3 AT&C Losses

The Distribution Licensee shall file AT&C Loss trajectory for monitoring AT&C Losses.

The percentage AT&C losses shall be calculated as per the following formula:

% AT&C losses=100-CEx(1-DL/100)

Where: CE is the % Collection Efficiency and
DL is the % Distribution Loss

57.4 Operation and Maintenance Expenses

The actual audited O & M expenses for the financial year preceding the base year, subject to prudence check, shall be escalated at the escalation factor of 4% to arrive at the O & M expenses for the base year of the control period. The O&M expenses for the n^{th} year of the control period shall be approved based on the formula given below.

$$O\&M_n = (R\&M_n + EMP_n + A\&G_n)*(1-X_n) + \text{Terminal Liabilities}$$

Where,

- $R\&M_n$ – Repair and Maintenance Costs of the Distribution Licensee(s) for the n^{th} year;
- EMP_n – Employee Costs of the Distribution Licensee(s) for the nth year excluding terminal liabilities;
- $A\&G_n$ – Administrative and General Costs of the Distribution Licensee(s) for the nth year;

The above components shall be computed in the following manner.

(a) $R\&M_n = K * GFA * INDX_n / INDX_{n-1}$

Where,

- **'K'** is a constant (expressed in %) governing the relationship between O&M costs and Gross Fixed Assets (GFA) for the n^{th} year. The value of K will be 1.65% for DHBVN and UHBVN respectively for the entire control period;
- ***'GFA'*** is the average value of the gross fixed asset of the n^{th} year.
- **'$INDX_n$'** means the inflation factor for the n^{th} year as defined herein after.

(b) EMP_n **(excluding terminal liabilities)** $+ A\&G_n = (EMP_{n-1} + A\&G_{n1})*(INDX_n/INDX_{n-1})$

Where,

- INDXn – Inflation Factor to be used for indexing the Employee Cost and A&G cost. This will be a combination of the Consumer Price Index (CPI) and the Wholesale Price Index (WPI) for immediately preceding year and shall be calculated as under:
- $INDX_n = 0.55*CPI_n + 0.45*WPI_n$.

Note 1: For the purpose of estimation, the same $INDX_n$ value shall be used for all years of the control period. However, the Commission shall consider the actual values of the $INDX_n$ at the end of each year during the annual performance review exercise and true-up the employee cost and A&G expenses on account of this variation.

Note 2: Any variation in employee cost and A&G cost on account of reasons beyond variation in $INDX_n$ shall be subject to the incentive and penalty framework specified in Regulation 12.

Note 3: As and when any material price index specific to power sector or a more relevant Index becomes available, the same shall replace the Index used for working out R&M cost.

Note 4: Terminal liabilities shall be approved as per actual expenditure incurred by the distribution licensee or established through actuarial valuation for the ensuing year.

Note 5: O&M expenses made on account of extraordinary situations (if any) shall be submitted to Commission for its approval. Such expenses shall be filed separately and will not be subjected to incentive and penalty framework. The approved amount by the Commission shall be trued up in the annual performance review.

Note 6: Changes in the pay scales of employees necessitated on account of pay revision by Pay Commission or by the State Government orders shall be considered by the Commission for true-up during the annual performance review.

Note 7: Source for CPI and WPI calculation as under:

Wholesale Price Index numbers as per Office of Economic Advisor of Government of India in the previous year;

Consumer Price Index for Industrial Workers (all India) as per Labour Bureau, Government of India in the previous year

(c) X_n is an efficiency factor for n^{th} year

The Value of X_n will be determined by the Commission in the MYT order for the control period.

58 SALES AND POWER PURCHASE VOLUME

58.1 The distribution licensee shall forecast monthly sales for each customer category and sub-categories for all years of the control period in their business plan and ARR filings, for review and approval by the Commission.

58.2 So long as there are any un-metered agriculture consumers, the sales forecast for unmetered agriculture consumer shall be validated with norms approved by the Commission on the basis of a proper study carried out by the distribution licensee.

Note: These norms can be revised by the Commission based on actual data or better estimates made available by the distribution licensee.

58.3 The Commission shall examine the forecasts for their reasonableness based on growth in the number of consumers, pattern of consumption, losses and demand of electricity in previous years and anticipated growth in the subsequent years and any other factor, which the Commission may consider relevant and approve the sales forecast with such modifications as deemed fit;

58.4 Sale of electricity, if any, to electricity traders or other distribution licensee or outside state sales through banking etc. shall be separately indicated;

58.5 The distribution licensee shall also indicate consumer category-wise open access consumers. The demand and energy wheeled for them shall be shown separately for:

(i) Supply within its area of supply; and

(ii) Supply outside its area of supply;

58.6 Based on the above, the distribution licensee shall project month- wise and source-wise power purchase requirement for each year of the control period.

58.7 The Commission shall scrutinize and approve the requirement for purchase of power with such modifications as deemed fit, for each year of the control period;

58.8 Any power purchased by the distribution licensee over and above the requirement of power approved by the Commission or variation in the mix of power purchased in any year shall be considered by the Commission if it is for reasons beyond the control of the distribution licensee(s). The Commission shall, however, estimate the revenue from such sales and allowable quantum of power purchase based on target losses as per the FSA mechanism approved by the Commission. The resultant cost and revenue shall be adjusted during true-up exercise for the said financial year in the next year's tariff;

58.9 Any financial gain or loss on account of power purchased by the licensee in any year over and above the approved level and not covered in the above sub Regulations shall be borne by the licensee.

59. COST OF POWER PURCHASE

59.1 The distribution licensee shall be allowed to recover the cost of power it procures from all sources including the power procured from the State-owned generating stations, independent power producers, Central generating stations, renewable energy sources and others, for supply of power to consumers, based on the sales forecast and losses for the distribution licensee approved by the Commission for each year of the control period;

59.2 Approved retail sales level shall be grossed up by normative level of T&D losses as specified by the Commission in the approved loss trajectory for the purpose of arriving at the quantity of power to be purchased;

59.3 While approving the cost of power purchase, the Commission shall determine the quantum of power to be purchased from various sources in accordance with the principles of merit order schedule and despatch based on a ranking of all approved sources of supply in the order of their variable cost of power. All power purchase costs will be considered legitimate unless the Commission concludes that the merit order principle has been violated or power has been purchased at unreasonable rates except for marginal purchases of transient nature beyond the control of the licensee subject, however, to Regulation 59.2;

59.4 The cost of power purchased by the distribution licensees from generating stations of HPGCL shall be worked out based on the tariff determined by the Commission. The cost of power purchase from central generating stations shall be worked out based on the tariff determined by the CERC. Similarly, the cost of power purchased from nuclear power stations of Nuclear Power Corporation of India Ltd. (NPCIL) shall be worked out on the basis of tariff notified by the Departmental of Atomic Energy under the Atomic Energy Act, 1961. In case of bilateral transactions, the rates as per PPAs approved by the Commission shall be considered. The cost of power purchase from other generating companies / sources shall be worked out based on invoices raised by the generators during the previous year. In absence of above, rates based on bills of energy purchased during the previous 3 months shall be considered by the Commission.

59.5 The cost of power purchase from non-conventional energy sources shall be based on the tariff determined by the Commission as per renewable energy Regulations notified by the Commission and as amended from time to time or as per the PPAs approved by the Commission.

59.6 Subject to provisions of clause 59.3, any variation in cost of power purchase at the allowed transmission loss level, for reasons beyond the control of the distribution licensee, shall be allowed to be recovered by the distribution licensee by way of FSA, as per the formula approved by the Commission and as amended from time to time. The procurement price to be adopted for working out variation in the cost of power beyond approved power purchase volume shall be the generation tariff approved by the Commission, the rate discovered through competitive bidding and adopted by the Commission or the short-term rates approved by the Commission.

59.7 Any loss on account of increase in power purchase cost, not covered above, shall be borne by the distribution licensee.

59.8 The Renewable Purchase Obligation (RPO) of the distribution licensee shall be as per the renewable energy Regulations notified by the Commission as amended from time to time.

60. SHORT-TERM POWER REQUIREMENTS

60.1 The distribution licensee shall submit a rolling quarterly forecast of the quantum of short-term power to be purchased for the year for the Commission's approval. The forecast shall be based on monthly sales forecast, the power available from approved long-term sources of power, merit order dispatch of available sources, banking with other distribution utilities, load curtailment, time of its requirement, availability of short-term power and the expected price. The distribution licensee shall provide the basis for forecast of short-term power procurement price including the criteria for evaluation of alternative options;

60.2 The Commission shall indicate the ceiling of short-term power purchase price and volume for the ensuing quarter based on the availability of power, past requirement, approved quantum of short-term power in ARR, approval granted for past quarter and past market performance. The Commission may ask for additional information and data as it may deem necessary for reviewing the forecast for the ensuing quarter and the distribution licensee shall furnish such information within 2 weeks from being asked to do so;

60.3 If there is a short term requirement of power by the distribution licensee over and above the quantum as approved by the Commission and such requirement is on account of any factor beyond the control of the distribution licensee (shortage/non-availability of fuel, snow capping of hydro resources inhibiting power generation in sources stipulated in the plan, unplanned/forced outages of power generating units or acts of God), then the cost shall be directly passed on to the consumers through FSA mechanism.

Provided that the cost of the additional power shall be allowed at the ceiling price for short term power determined by the Commission in accordance with Regulation 60.2.

Provided further that in such a case, the distribution licensee shall inform the Commission about the purchase of power over and above approved quantum with all of the supporting documents. Unless the Commission is satisfied that the additional power is within the ceiling price of short-term power determined by the Commission, it may disallow the quantum and cost of this short-term power procurement in the True-Up order.

60.4 The variation in actual quantum and price of short-term power vis-a-vis the quantum and price of short-term power approved by the Commission shall be subjected to prudence check by the Commission and shall be adjusted on yearly basis along with the annual performance review based on the price and quantum cap determined by the Commission for each quarter as mentioned in the above Regulation.

61. TRANSMISSION AND SLDC CHARGES

61.1 The Inter-State transmission charges shall be estimated as per the order of the Central Electricity Regulatory Commission

61.2 The transmission charges, wheeling charges and other charges payable by the distribution licensee for intra State transmission or wheeling of power purchased by it shall be considered as per tariff determined by the Commission;

61.3 The reactive energy charges payable by the distribution licensee to the transmission licensee shall be payable as per Regulation 5.5.1 of the Haryana Grid Code (HGC) as amended from time to time.

The reactive energy charges paid by the distribution licensee however shall not be recovered through ARR. The capital investment plan to be prepared by the distribution licensee shall include capital investment towards meeting the reactive energy requirement.

61.4 SLDC charges if paid separately in addition to charges for usage of transmission network shall be considered as allowable expenses for the purpose of determination of tariff.

62. WHEELING CHARGES

62.1 The consumers availing wheeling services for ‘open access’, will be charged a wheeling tariff as determined under these Regulations;

The wheeling charge payable to the distribution licensee by long-term & medium-term open access consumers shall be in Rs. / MW and shall be computed by dividing the approved ARR of the licensee for wheeling business by peak load demand in MW served by the licensee in the preceding year.

Provided that wheeling charges shall be payable by the long-term and medium-term open access consumers on the basis of contracted capacity in MW and by short-term open access consumers on the basis of scheduled energy transactions cleared by the relevant Load Despatch Centre.

Provided further that wheeling charges (Rs. /kWh) payable by the short-term open access consumers during a financial year shall be worked out by dividing the approved ARR (in Rs.) for wheeling business for that year by the gross volume of energy wheeled (kWh) during the previous year.

62.2 **Income from wheeling from open access consumers**:

25% of the wheeling charges collected from open access consumers shall be retained by the distribution licensees and the balance 75% shall be adjusted towards reduction of ARR for the retail supply business.

Provided that Wheeling Losses: The Distribution Licensee shall be allowed to recover the approved level of wheeling losses arising from the operation of the distribution system, as stipulated in the respective Tariff Order.

63. CROSS-SUBSIDY SURCHARGE / ADDITIONAL SURCHARGE

63.1 The cross-subsidy surcharge and additional surcharge under sections 39, 40 and 42 of the Act shall be determined as per the open access Regulations notified by the Commission as amended from time to time;

Cross-subsidy surcharge shall also be payable by such open access consumer who receives supply of electricity from a person other than the distribution licensee in whose area of supply he is located, irrespective of whether he avails such supply through transmission/distribution network of the licensee or not.

The consumers located in the area of supply of a distribution licensee but availing open access exclusively on inter-State transmission system shall also pay the cross subsidy/additional surcharge.

63.2 The cross-subsidy surcharge and additional surcharge shall be considered as non-tariff income for retail supply. The licensee shall provide the consumer category-wise details of the cross – subsidy and additional surcharge received during the year along with the tariff filings.

63.3 The distribution licensee shall also submit along with ARR, requisite calculation for determination of cross subsidy surcharge and additional surcharge by the commission. The cross-subsidy surcharge and additional surcharge shall be payable as determined by the commission from time to time.

64 BAD AND DOUBTFUL DEBTS

Bad and doubtful debts shall be allowed to the extent the distribution licensee has actually written off bad debts subject to a maximum of 0.5% of sales revenue. However, this shall be allowed only if the distribution licensee submits all relevant data and information to the satisfaction of the Commission. In case there is any recovery of bad debts already written off, the recovered bad debts will be treated as other income.

Treatment of Demand Side Management Initiatives

The Commission shall introduce various policies like Time of Day (ToD) Tariff pertaining to Demand Side Management in order to flatten the Load Curve of the State and optimise the Power Purchase Cost.

The consumers who install Smart Meters on their own, tested by Independent third party- National Accreditation Board for Testing and Calibration Laboratories (NABL) or any other accredited meter testing lab certified through Govt. of India, in their premises shall be benefitted from the ToD automatically.

The Distribution licensee shall also strive to replace existing meters with Smart Meters in Urban Areas and Pre-Paid meters in Rural Areas.

Provided that Distribution Licensee shall submit quarterly progress report in this regard to the Commission.

Provided also that Distribution Licensee shall submit the utilization of funds allocated for DSM schemes and shall maintain separate records of Revenue/Expenditure related to individual DSM schemes approved by the Commission.

65 QUALITY AND RELIABILITY OF SUPPLY

65.1 Distribution Transformers failure rate

(i) The commission shall specify the norms for maximum permissible distribution transformers' failure rate separately for urban and rural areas in the MYT order;

(ii) In case the maximum permissible failure rate of distribution transformers exceeds the limits specified above, the return on equity in Rs. crores shall be reduced as mentioned below

For Rural Areas

Absolute increase (%) in distribution transformers failure rate from the norm	Percentage reduction in ROE (Rs. Crores).
0	0
>0≤5 %	1%
>5≤10 %	2%
>10≤15%	3%
>15≤20%	5%
>20	5%+ Absolute increase (%) / 20%

For Urban Areas

Absolute increase (%) in distribution transformers failure rate from the norm	Percentage reduction in ROE (Rs. Crores)
0	0
>0≤2.5%	1%
>2.5≤5%	2%
>5≤7.5%	3%
>7.5≤10%	5%
>10 %	5%+ Absolute increase (%) / 10%

Example: In case actual damage rate is 7% against normative damage rate of 5%, then absolute increase is 2 %.

(iii) The distribution licensee shall maintain a proper record of failure of the distribution transformers and submit the same in the quarterly report to the Commission.

65.2 Monitoring progress on Standards of Performance

(i) The distribution licensee shall provide requisite report on the progress of compliance of the performance parameters as specified in the HERC (Standards of Performance for the Distribution licensee) Regulations, 2004 as amended from time to time;

(ii) The transmission licensee shall also provide requisite report on the progress of compliance of the performance parameters as may be specified by the Commission in the "Standards of Performance for the Transmission Licensee Regulations" to be notified by the Commission and as amended from time to time.

(iii) In case the distribution/transmission licensee fails to submit the report to Commission or delays the submission by more than 2 months, the commission may reduce the return on equity by 0.50% if the licensee is not able to provide adequate justification for the delay.

(iv) The distribution licensee shall submit and upload on their website circle-wise quarterly report containing the following for their respective circle: -

(a) Details of expenditure along with cost benefits analysis of each expenditure costing above Rs. 2.50 lakh
(b) Distribution loss along with the reason for loss above 15%
(c) Status of pending connections (numbers & load)
(d) Sale of power and billing done in the previous quarter along with the status of recovery.
(e) Failure rate of transformers under warranty/out of warranty separately for rural & urban area
(f) Three phase and single-phase defective meters pending for replacement

(v) The distribution licensee shall not distribute power to any category of consumers free of cost. No approval from the Commission shall be sought in this regard.

(vi) The distribution licensee shall submit Voltage wise loss data along-with their True-up Petitions.

65.3 Audited Information

The Distribution Licensees shall submit the following Audited Information for the relevant Financial Year along-with their True-up Petitions:

a) Category wise Sales

b) Category-Wise Break up of Revenue Billed
   - Fixed Charges,
   - Energy Charges,
   - Fuel Adjustment Surcharge etc.

c) Category-wise Revenue Collected

66 FUEL AND POWER PURCHASE COST SURCHARGE ADJUSTMENT (FSA)

66.1 The distribution licensees shall recover FSA amount on account of increase in fuel and power purchase costs from the consumers on a quarterly basis so as to ensure that FSA accrued in a quarter is recovered in the following quarter without going through the regulatory process i.e. FSA for the quarter “July to September” is recovered in the following quarter “October to December”.

66.2 FSA shall be calculated only in respect of approved power purchase volume including short term power purchase cost, if any, for the relevant year from all approved sources. Drawl of power under UI mechanism, if any, shall be allowed only when it is not in violation of grid discipline and shall be subject to a price cap of average revenue realisation from all consumer categories for that year.

Average revenue realisation = (Total revenue assessed for electricity supply in Rs + Government Subsidy in Rs) / Total sales in Units.

66.3 For the purpose of recovery of FSA, power purchase cost shall include all invoices raised by the approved suppliers of power and credits received by the distribution licensees during the quarter irrespective of the period to which these pertain for any change in cost in accordance with tariff approved by any regulator/ government agency mentioned in Regulation 59.4. This shall include arrears/refunds, if any, not settled earlier. In case data of the last month in a quarter is not available for calculating FSA to be levied in the following quarter, the licensee shall use an estimate based on available data of the first two months of the quarter. On availability of the actual figures, the difference on this account shall form part of FSA of the subsequent quarter. If the actual data for any quarter is not made available by the licensee before the end of the following quarter for this adjustment, the FSA finally allowed for that quarter based on actual figures supplied after the prescribed date shall be limited to the earlier estimated amount or the amount based on the actual figures, whichever is lower.

66.4 In case of negative FSA, the credit shall be given to the consumers by setting off the minus figure against the positive figure of FSA being charged from the consumers. In other words, credit of FSA shall be given only against FSA being charged so that the base tariff determined by the Commission remains unchanged.

66.5 Only the allowed percentage of transmission and distribution losses for the relevant year as per the approved ARR shall be considered for working out FSA.

66.6 The amount of FSA shall be recovered by each distribution licensee by charging a uniform FSA (per kWh) across all consumer categories in his area of license.

66.7 For moderation purposes, the recovery of per unit FSA shall be limited to 10% of the approved per unit ‘average power purchase cost’ or such other ceiling as may be stipulated by the Commission from time to time. For calculating FSA, variations in quarterly purchase volume from an approved source are allowed subject to an overall ceiling of annual approved volume from that source. In case a portion of the FSA for any quarter is not recovered due to the ceiling of 10%, the under recovered amount shall be added to the FSA for the next quarter.

66.8 Per unit rate of FSA (paisa/kWh) shall be worked out after rounding off to the nearest paisa;

66.9 The distribution licensee shall submit details relating to FSA recovery to the Commission for each quarter in the following format by the end of the following quarter.

(i)	Approved power purchase volume from approved sources (MU)
(ii)	Approved power purchase cost (Rs. million)
(iii)	Actual power purchase volume (MU)
(iv)	Power purchased (MU) from sources not covered under Regulation 66.2 giving source wise details and in case of UI the frequency at which UI drawls were made. (disallowed power purchase)
(v)	Actual cost of power purchase from all sources except (iv) (Rs. million)
(vi)	Actual cost of disallowed power purchase relating to (iv) (Rs. million)
(vii)	Total FSA estimated to be recovered for the quarter (Rs. million)
(viii)	FSA per unit (Rs/kWh) being recovered during the following quarter
(ix)	Actual FSA recovered/estimated to be recovered out of estimated FSA till the end of the following quarter (Rs. million)
(x)	Under/ over recovered FSA (vii-ix) (Rs. million)
(xi)	Approved sales (Consumer category wise / month wise) for the quarter (MU)
(xii)	Actual sales (Consumer category wise / month wise) for the quarter (MU)
(xiii)	Estimated sales, consumer category wise, for the following quarter (MU)

Note:

1. All the source-wise details should be supported with requisite documentary evidence / invoices raised by the generators / suppliers of the power.
2. Actual sales to AP consumers are to be calculated in accordance with the methodology approved by the Commission in the ARR for the relevant year.

66.10 FSA (Rs/kWh) shall be worked out as per the following formula:

Total FSA (Rs million) = $PC + I_{nt} + A_{dJst}\,Q + (A_{dJst}A/4)$

FSA (Rs / kWh) = $\{PC + I_{nt} + A_{dJst}\,Q + (A_{dJst}A/4)\} \div PS$

Where

- PC = {(Actual average power purchase cost (Rs/kWh) for the quarter) - (Average power purchase cost (Rs/KWh) approved by the Commission for the relevant year)} X PP
- PP = Total volume of power purchase during the quarter worked out based on total volume of powers sold to all the consumer categories grossed up by approved T&D loss. Sales to AP consumers are to be worked out in accordance

with the methodology approved by the Commission in the ARR for the relevant year (MU).

- PS = Estimated sales volume for the following quarter with AP sales as approved by the Commission in the ARR for the relevant year (MU).
- Actual average power purchase cost (Rs. /KWh) = (total cost of power purchased during the quarter from approved sources and UI as per Regulation 66.2 in Rs million) / (total volume of power purchased in the quarter from approved sources and UI in MU) as per Regulation 66.2)
- I_{nt} = Additional working capital cost allowed on account of FSA amount to be worked out as under:

  I_{nt} = {(total FSA/12) X (interest rate allowed for calculation of working capital in the ARR of the current financial year)} in Rs million.
- A_{dJst} Q = Under/over recovered FSA of the previous quarter in accordance with Regulation 66.3 and 66.7 in Rs million.
- A_{dJst}A = Annual adjustment amount based on truing up of the FSA of the previous year by the Commission in Rs million.

66.11 The licensee shall ensure that the Actual/ estimated FSA arising in a quarter is recovered in the following quarter. In case the licensee does not ensure levy of FSA based on the methodology given herein, the licensee shall have no claim to recover the FSA from the consumers in any manner in any subsequent period except in accordance with Regulation 66(3) and 66(7). The unrecovered FSA for the previous financial year, details of which are supplied to the Commission by the distribution licensee, may either form part of power purchase cost for the next financial year or may be allowed to be recovered as annual adjustment amount in the quarterly recovery of FSA in the next financial year as the Commission may decide.

66.12 In case Government of Haryana decides to provide subsidy on account of FSA to a particular consumer category, the amount of subsidy equivalent to the FSA recoverable from the concerned consumer category, shall be deposited in advance by the Govt. Otherwise the recovery shall be affected from the consumer through electricity bills. It shall be the responsibility of the distribution licensees to seek prior approval of the State Government in this regard and maintain appropriate record of the same.

67. NON-TARIFF INCOME

67.1 All incomes being incidental to electricity business and derived by the licensee from sources, including but not limited to profit derived from disposal of assets, rents, delayed payment surcharge, meter rent, income from investments other than contingency reserves, miscellaneous receipts from the consumers, etc shall constitute non-tariff income of the licensee;

67.2 The amount received by the distribution licensee on account of non-tariff income shall be deducted from the aggregate revenue requirement in calculating the net revenue requirement.

Provided that the distribution licensee shall submit full details of his forecast of non-tariff income to the Commission in such form as may be stipulated by the Commission from time to time.

Provided that Late Payment Surcharge and Interest on Late Payment earned by the Distribution company shall not be considered under Non-tariff Income.

67.3 The "non-tariff income" shall include but shall not be limited to the following:

a. Income from rent of land or buildings or other assets;
b. Income from sale of land and other assets;
c. Income from sale of scrap;
d. Income from statutory investments;
e. Income from interest on contingency reserve investment;
f. Interest on advances to suppliers/contractors;
g. Rental from staff quarters;
h. Rental from contractors;
i. Income from hire charges from contactors and others;
j. Income from advertisements, etc.;
k. Miscellaneous receipts;
l. Interest on advances to suppliers;
m. Excess found on physical verification;
n. Deferred Income from grant, subsidy, etc., as per Annual Accounts;
o. Prior period income, etc.

68. SUBSIDY

68.1 Pursuant to Section 65 of the Electricity Act, 2003 in case the State Government requires grant of any subsidy to any consumer or class of consumers in the tariff determined under Section 62, the distribution licensee should ensure that the State Government shall, notwithstanding any direction which may be given under Section 108, pay in advance the requisite amount as determined by the Commission to compensate the distribution licensee affected by the grant of subsidy.

68.2 A tariff reflecting subsidy shall not be implemented except to the extent that the State Government has paid the subsidy to the distribution licensee in advance of supply to the consumers of the distribution licensee entitled to benefit from it. In publishing its tariff, the distribution licensee shall inform its consumers that the approved tariff calculated without subsidy shall apply if the State Government subsidy is not so paid as determined by the Commission. The, 'bill' issued by the distribution licensee shall clearly indicate:

a) the tariff determined by the Commission;

b) the amount of State Government subsidy, the rate and period;

c) the net amount payable by the consumer;

68.3 The amount of subsidy agreed to by the State Government may be provided in the form of payment in cash in advance as per section 65 of Electricity Act or by book adjustment of net dues payable by the distribution licensee to the State Government. The book adjustment shall be done on the basis of cash in hand with the distribution licensee and not on an accrual basis in respect of dues to be collected by the distribution licensee from consumers on behalf of the State Government.

69 An INTER CATEGORY CROSS–SUBSIDY

69.1 The distribution licensee's tariff proposal should reflect the reasonable cost of providing service to each consumer class. In case where tariffs are historically distorted with significant level of cross-subsidy, the aim should be to gradually move to non-cross subsidized tariffs.

69.2 In the annual performance review and tariff application, the distribution licensee shall include a report on how far they have implemented the cross-subsidy reduction trajectory approved by the Commission for reduction of cross-subsidy and the measures being proposed in the current application to implement the plan.

PART VIII - FILING OF AGGREGATE REVENUE REQUIREMENT

70. Capital Investment Plan and Business Plan Filings

The distribution licensee shall file by 1st June and the generating company and the transmission licensee by 1st September of the year preceding the first year of the control period or any other date as may be directed by the Commission, an application containing the following elements for the approval of the Commission, along with requisite fee in accordance with the provision of HERC (Fee) Regulation, 2005:

(a) Capital Investment Plan as per details specified in Regulation 9.

(b) Business Plan as per details specified in Regulation 10.

71. Tariff Filings

71.2 Tariff filing for the control period under MYT framework

71.2.1 The generating company and the licensees shall file an application for approval of ARR for their respective businesses for each year of the control period and tariff for the first year of the control period consistent with the business plan and the capital investment plan approved by the Commission. The ARR and tariff filing shall be filed by 30th November of the year preceding the 1st year of the control period along with requisite fee in accordance with the provisions of Haryana Electricity Regulatory Commission (Fee) Regulations amended from time to time. The application shall contain all the components of the ARR and tariff as provided in these Regulations;

The MYT filing shall also contain an application for mid-year performance review of and true – up petition.

71.2.2 The generation company and the licensees shall provide in the application forecast for each year of the control period of the various financial and operational parameters of ARR & various other components of the ARR and tariff relating to their respective businesses as mentioned in these Regulations. The application, in case of a distribution licensee and a transmission licensee shall also include:

(i) **For distribution licensee**

(a) Sales / demand forecast for each consumer category and sub-categories for each year of the control period and the methodology and rationale used;

(b) Power procurement plan based on the sales forecast and distribution loss trajectory for each year of the control period. The power procurement plan should also keep in view energy efficiency and demand side management measures;

(c) A set of targets proposed for other controllable items such as collection efficiency, recovery of bad debts, working capital, quality of supply targets, etc. The targets shall be consistent with the capital investment plan and business plan approved by the Commission;

(d) Expected revenue from the licensed business, non-tariff income and income from other business for the base year and first year of the control period and other matters considered appropriate by the distribution licensee(s);

(e) Number of consumers in each category, connected load in kW and estimate of the cost of supply for various consumer categories per kW and per kWh

(f) The ARR for various years of the control period, the revenue gap and tariff proposal for meeting the revenue gap for first year of the control period. The tariff proposal should be based on the cost of supply for various consumer categories and the cross-subsidy reduction road map.

(g) Proposal for meeting the projected cumulative revenue gap for first year of the control period which shall include mechanism for meeting the proposed revenue gap, tariff revision for various consumer categories etc. In the absence of tariff proposal, the application/petition shall be considered as incomplete and shall be liable for rejection.

(h) A statement of the effect of the proposed tariff changes on a typical small, average and large consumer in each tariff class. For this purpose, a typical small consumer is defined such that within the tariff class, 90% of the consumers supplied under that tariff within a 12-month period would have greater total expenditure on tariff charges than the small consumer. Similarly, a typical large consumer is defined such that 90% of the consumers supplied under the tariff would have lesser expenditure over a 12-month period than the typical large consumer. The average consumer shall be defined as a consumer having expenditure on tariff charges equal to the average expenditure in that tariff class.

(ii) **For transmission licensee**

(a) The Transmission system or network usage forecast for each year of the Control Period, consistent with the Business Plan;

(b) Proposal for transmission tariff design for each year of the Control Period, including the losses to be charged and the procedure thereof;

(c) Proposal for transmission tariff for each year of the Control Period supported by the adequate justification;

(d) Estimates of Transmission Capacity allocated to each of the Transmission system user for each year of the control period

(e) Proposal for reactive energy charges;

(f) Proposal for SLDC charges (in case SLDC is controlled by the transmission licensee);

(g) Expected Revenue from the licensed Business, Non-Tariff Income and income from Other Business and other matters considered appropriate by the Transmission Licensee.

71.3 The generating company and the licensee shall also provide a copy of their respective ARR/tariff filing to each other;

71.4 The generating company and the licensees, within 7 (seven) days of filing of the application for approval of ARR/Tariff, shall publish in Hindi and English in daily newspapers having circulation in the area of licensees /generation company, the contents of the application filed for approval of ARR/Tariff in an abridged form in such manner as the Commission may direct for information of the public and shall provide copies of the application and other documents filed with the Commission at a price not exceeding normal photocopying charges. The generating company and the licensees shall also host the application and other documents at their websites.

71.5 The distribution licensee shall undertake a separate study to estimate the cost of supply for various consumer categories and submit the same to the Commission for its approval along with the MYT filing;

71.6 The distribution licensee shall also undertake a study for preparation of road map for reduction of cross-subsidy and submit the same to the Commission for its approval along with the MYT filing;

71.7 Notwithstanding anything contained in these Regulations, the Commission may at all times, either Suo motu or on a petition filed by any interested or affected party, determine the tariff, including terms and conditions thereof, of any generating company or the licensee;

71.8 **Approval of provisional tariff for a generating station**

A Generating Company may also file a petition, not more than six months prior to the anticipated Date of Commercial Operation (COD), for determination of provisional tariff of the Unit or Stage or Generating Station as a whole, as the case may be, based on the capital expenditure actually incurred up to the date of making the petition or a date prior to making of the petition, duly audited and certified by the statutory auditors and the provisional tariff shall be charged from the date of commercial operation of such Unit or Stage or Generating Station, as the case may be.

Provided that the Generating Company shall file a fresh petition in accordance with these Regulations, for determination of final tariff based on actual capital expenditure incurred up to the date of commercial operation of the Generating Station duly certified by the statutory auditors based on Annual Audited Accounts.

Provided further that any difference in provisional tariff and the final tariff determined by the Commission and not attributable to the Generating Company may be adjusted at the time of determination of final tariff for the following year as directed by the Commission.

71.9 **Filing for Mid-year performance review, True-up and determination of tariff for ensuing year**

The generating company and the licensees shall file their application for mid-year performance review of the current year, true-up of the previous year and tariff for the ensuing year along with requisite fee by 30th November of each year of the control period as per the details mentioned in the Regulation 11 & 13 for the Commission's review, true-up of uncontrollable / controllable items in accordance with Regulation 8.3 and approval of tariff for the ensuing year.

72. TARIFF ORDER

72.1 The Commission shall, within one hundred and twenty (120) days from the receipt of a complete application and after considering all suggestions and objections received from the public/other stakeholders:

(i) Issue a tariff order accepting the application with such modifications or such conditions as may be contained in such order; or

(ii) Reject the application for reasons to be recorded in writing if such application is not in accordance with the provisions of the Act and the rules and Regulations made thereunder or the provisions of any other law for the time being in force and direct the licensee to resubmit the application after such modifications/amendments as may be directed by the Commission.

Provided that the applicant shall be given a reasonable opportunity of being heard before rejecting the application.

72.2 The tariff so determined by the Commission shall be in force from the date specified in the said order and shall, unless amended or revoked, continue to be in force for such period as may be stipulated therein.

73. PUBLICATION OF APPROVED TARIFF

The generating company and the licensees, as the case may be, shall publish the tariff approved by the Commission in Hindi and English in daily newspapers having wide circulation in the area of distribution licensees and shall put up the complete tariff petition, including annexure, and approved tariff / tariff schedule on its website and make available for sale, a booklet containing such tariff or tariffs, as the case may be, to any person upon payment of reasonable reproduction charges.

74. PERIODIC REVIEWS

74.1 To ensure smooth implementation of the Multi Year Tariff (MYT) framework, the Commission may undertake periodic reviews of performance during the control period, to address any practical issues, concerns or unexpected outcomes that may arise.

74.2 The generating company and the licensee shall submit information as part of annual review on actual performance to assess the performance vis-à-vis the targets approved by the Commission at the beginning of the control period. This shall include annual statements of its performance and accounts including latest available audited / actual accounts and the tariff worked out in accordance with these Regulations.

74.3 The Commission may approve any modifications to the forecast of the generating company or the licensee for the remainder of the control period, with detailed reasons for the same.

75. SUMMARY OF TIMELINES

Generating company and the licensee shall adhere to the following schedule for various activities for the first control period:

Time Schedule for various activities for the 2nd Control Period

S. No	Description	Filing of the Document	Obtaining additional information and acceptance by the Commission	Approval of the Document by the Commission
1	Capital Investment Plan (to be filed only at the beginning of Control Period)	By 1st June by distribution licensee and by 1st August by the generation company/transmission licensee of the year preceding the first year of the control period	Within 30 days of filing of document	Within 45 days of acceptance of the filing
2	Business Plan	By 1st June by distribution licensee	Within 30 days of filing of document	Within 45 days of acceptance of the filing

S. No	Description	Filing of the Document	Obtaining additional information and acceptance by the Commission	Approval of the Document by the Commission
		and by 1st August by the generation company/transmission licensee of the year preceding the first year of the control period		or from the date of receipt of additional information whichever is later
3	Filing of MYT Petition (ARR and Tariff Proposal for the control period)	By 30th November of the year preceding the first year of the control period	Within 30 days of filing of document	Within 120 days of acceptance of the filing but by 1st of April of the 1st year of the control period in any case
4	Mid -year Performance Review/True -up	By 30th November of each year of the control period	Within 30 days of filing of document	Within 120 days of acceptance of the filing

PART IX - MISCELLANEOUS

76. HEARING

76.1 The Commission may hold hearing(s) on the ARR/tariff filing and hear such persons as the Commission may consider appropriate to decide on such ARR/tariff filing.

76.2 The procedure of hearing on the ARR/Tariff filing shall be as per the provisions of the HERC (Conduct of Business) Regulations, 2004 as amended from time to time or in the manner as the Commission may decide from time to time.

76.3 Where the Commission is satisfied that the appointment of a consultancy company is essential in order to arrive at a just and fair conclusion in any matter before it and so appoints some consultancy company, it may require the generating company and the licensee to pay for the costs of such consultancy, which shall be allowed as a pass through in the ARR.

77. ISSUE OF ORDERS AND DIRECTIONS

Subject to the provision of the Act and these Regulations, the Commission may, from time to time, issue orders and directions in regard to the implementation of these Regulations and procedure to be followed on various matters.

78. POWERS TO REMOVE DIFFICULTIES.

If any difficulty arises in giving effect to any of the provisions of these Regulations, the Commission may, by a general or special order, not being inconsistent with the provisions of these Regulations or the Act, do or undertake to do things or direct the generating company or the licensee to do or undertake such things which appear to be necessary or expedient for the purpose of removing the difficulties.

79. POWER TO RELAX

The Commission may in public interest and for reasons to be recorded in writing, relax any of the provision of these Regulations.

80. INTERPRETATION

If a question arises relating to the interpretation of any provision of these Regulations, the decision of the Commission shall be final.

81. SAVING OF INHERENT POWERS OF THE COMMISSION

81.1 Nothing in these Regulations shall be deemed to limit or otherwise affect the inherent power of the Commission to make such orders as may be necessary for ends of justice or to protect consumers' interest or to prevent the abuse of the process of the Commission.

81.2 Nothing contained in these Regulations shall limit or otherwise affect the inherent powers of the Commission from adopting a procedure, which is at variance with any of the provisions of these Regulations, if the Commission, in view of the special circumstances of the matter or class of matters and for reasons to be recorded in writing, deems it necessary or expedient to depart from the procedure specified in these Regulations.

81.3 Nothing in these Regulations shall, expressly or by implication, bar the Commission to deal with any matter or exercise any power under the Act for which no Regulations have been framed, and the Commission may deal with such matters, powers and functions in a manner it thinks fit.

82. ENQUIRY AND INVESTIGATION

All enquiries, investigations and adjudications under these Regulations shall be done by the Commission through the proceedings in accordance with the provisions of the Conduct of Business Regulations, 2004 as amended from time to time.

83. POWER TO AMEND

The Commission, for reasons to be recorded in writing, may at any time vary, alter or modify any of the provision of these Regulations after following the due process.

84. REPEAL

The Haryana Electricity Regulatory Commission (Terms and Conditions for Determination of Tariff for Generation, Transmission, Wheeling and Distribution & Retail Supply under Multi Year Tariff Framework) Regulations, 2012 including its subsequent amendments shall stand repealed.

Appendix I

Procedure for Calculation of Transmission System Availability Factor

It will be governed as per CERC regulations, issued from time to time.

Appendix II

Depreciation Schedule

S. No	Asset Particulars	Useful life (Years)	Depreciation Rate for first 12 years of the useful life w.e.f COD (Salvage Value = 10%)
A	**Land under full ownership**	Infinite	0
B	**Land under lease**		
(a)	for investment in the land	The period of lease or the period remaining unexpired on the Assignment of the lease	0
(b)	for cost of clearing the site	The period of lease remaining unexpired at the date of clearing the date	0
C	**Assets purchased new**		
(a)	Plant and Machinery in generating plants		
(i)	Hydro electric	35	5.28%
(ii)	Coal based and WHRB based thermal plants	25	5.28%
(iii)	Diesel electric and gas plant	15	5.28%
(b)	Cooling towers & Circulating Water Systems	25	5.28%
(c)	Hydraulic works forming part of the Hydro-electric project		
(i)	Dams, Spillways, Weirs, Canals, Reinforced	50	5.28%

S. No	Asset Particulars	Useful life (Years)	Depreciation Rate for first 12 years of the useful life w.e.f COD (Salvage Value = 10%)
	concrete flumes and siphons		
(ii)	Reinforced concrete pipelines and surge tanks, steel pipelines, sluice gates, steel surge tanks, hydraulic control valves and hydraulic works	35	5.28%
D	**Building & Civil Engineering works of a permanent character, not mentioned above**		
(i)	Offices and showrooms	50	3.34%
(ii)	Containing thermo-electric generating plant	25	3.34%
(iii)	Containing hydro-electric generating plant	35	3.34%
(iv)	Temporary erections such as wooden structures	-	100%
(v)	Roads other than Kutcha roads	50	3.34%
(vi)	Others	50	3.34%
E	**Transformers, Transformer Kiosk, Sub-Station equipment & other fixed apparatus (including plant foundations)**		
(i)	Transformers including foundations having rating of 100 KVA and over	25	5.28%
(ii)	Others	25	5.28%
F	**Switchgear including cable connections**	25	5.28%
G	**Lightning arrestors:**		
(i)	Station type	25	5.28%
(ii)	Pole type	15	6.33%
(iii)	Synchronous condenser	35	5.28%
H	**Batteries**	5	5.28%

S. No	Asset Particulars	Useful life (Years)	Depreciation Rate for first 12 years of the useful life w.e.f COD (Salvage Value = 10%)
I	**Underground cable including joint boxes and disconnected boxes**	35	5.28%
J	**Cable duct system**	50	5.28%
K	**Overhead lines including supports**		
(i)	Lines on fabricated steel towers operating at nominal voltages higher than 66 KV	35	5.28%
(ii)	Lines on steel supports operating at nominal voltages higher than 13.2 KV but not exceeding 66 KV	25	5.28%
(iii)	Lines on steel or reinforced concrete supports	25	5.28%
(iv)	Lines on treated wood supports	25	5.28%
L	**Meters**	15	5.28%
M	**Self-propelled vehicles**	5	9.50%
N	**Air Conditioning Plants**		
(i)	Static	15	5.28%
(ii)	Portable	5	9.50%
O	**Office equipments**		
(i)	Office furniture and furnishing	15	6.33%
(ii)	Office equipment	15	6.33%
(iii)	Internal wiring including fittings and apparatus	15	6.33%
(iv)	Street Light fittings	15	5.28%
P	**Apparatus let on hire**		
(i)	Other than motors	5	9.50%
(ii)	Motors	15	6.33%
Q	**Communication equipment**		
(i)	Radio and high frequency carrier system	15	6.33%
(ii)	Telephone lines and telephones	15	6.33%

S. No	Asset Particulars	Useful life (Years)	Depreciation Rate for first 12 years of the useful life w.e.f COD (Salvage Value = 10%)
R	**IT equipments**	6	15.00%
S	**Fibre optic**	15	6.33%
T	**Any other assets not covered above**	15	5.28%

By Order of the Commission

Director / Tariff
HERC