TARIFF DETERMINATION METHODOLOGY FOR THERMAL POWER PLANT

1. Background

The Electricity Act 2003 has empowered the Central Electricity Regulatory Commission (CERC) to specify the terms and conditions for the determination of tariff in respect of the generating companies that are either owned by the Central Government or supply power to more than one State. The CERC is also empowered to determine the tariff that can be levied by transmission licensees for inter-State transmission of electricity.

Section 61 of the Act empowers the Commission to specify, by regulations, the terms and conditions for the determination of tariff in accordance with the provisions of the said section and the National Electricity Policy and Tariff Policy.

After the enactment of the Electricity Act 2003, the CERC had come out with tariff regulations for the period FY 2004-09 in March 2004. Post the expiry of earlier Regulations on March 31, 2009, the CERC had notified new tariff regulations on January 19, 2009 for the next regulatory period FY 2009-14. The new regulations apply to all generating stations (excluding stations based on non-conventional energy sources) and transmission licensees, provided that the tariffs for these entities have not been determined through bidding process in accordance with the guidelines issued by the Central Government.

The Tariff regulations notified by the CERC are also important for the various State Electricity Regulatory Commissions (SERCs) as they are guided by these regulations while framing their own tariff principles for the State sector utilities concerned.

2. Regulatory Norms for Computation of Tariff

This section discusses the regulatory norms for the computation of tariff for thermal power station.

For thermal power generating stations (coal, lignite and gas based), the CERC has been adopting a two-part tariff:

1) Capacity Charges (for recovery of Annual Fixed Costs)

2) Energy Charges (for recovery of Primary Fuel Costs)

3. Components of Capacity Charges/Annual Fixed Charge (AFC)

Component of AFC		FY 2009-14
a	Return on Equity	15.50%
b	Interest on Loan Capital	As per actual
c	Depreciation	5.28%
d	Interest on Working Capital	Based on Normative Parameters
e	Operation & Maintenance Costs	Based on Normative Parameters
f	Cost of Secondary Oil	Based on Normative Parameters
g	Special allowance in lieu of R&M	Based on Plant life

(a) Return on Equity

CERC has specified a Pre-Tax RoE of 15.5% for the tariff period FY 2009-14. Further, it has allowed an additional RoE of 0.5% for projects commissioned after April 2009 within specific timelines. The additional RoE allowed by CERC is acting as an incentive for a project developer to achieve time-bound milestones. On the other hand, the Tariff Regulations does not allow utilities to recover tax on income such as unscheduled interchange (UI) and incentive income from beneficiaries.

(b) Interest on Loan Capital

The CERC has specified a debt-equity ratio of 70:30 as the funding mix for the capital cost of a project. The interest rate as per actuals on these loan funds is recoverable as part of the tariff. The Tariff Regulations allows retention of 1/3rd of the benefits, if any, arising out of re-financing of loans; earlier such benefits were required to be passed on entirely to the beneficiaries.

(c) Depreciation

In the Regulations for the earlier tariff periods, the CERC followed the concept of Advance against depreciation (AAD) in case where the normal depreciation rates (notified by the regulator) were not sufficient to meet the debt repayment obligation of the utility.

In the Tariff regulations for the period FY 2009-14 the CERC has removed the concept of AAD, it has at the same time increased the depreciation rates applicable for projects. As against the earlier deprecation rate of 3.6% for thermal power projects (based on a 25-year project life and 90% of the capital cost), the CERC has increased the depreciation rate to 5.28% for most components of the project.

(d) Interest on Working Capital

The working capital for a thermal power station has following components:

Components		FY 2009-14
1	Coal Stock	1½ Months for Pit Head 2 Months for Non-Pit Head
2	Secondary Fuel Oil Stock	2 Months
3	Maintenance Spares	20% of O&M Costs – Coal Based 30% of O&M Costs – Gas Based
4	Sales Receivables	2 Months
5	O&M expenses	1 Month

(e) Operations & Maintenance Costs

The CERC has specified O&M Costs for thermal power stations on the normative parameters (Rs. lakh/MW), depending on the class of the machine installed by the power station. The normative O&M expenses allowed are:

Rs Lakh/MW	200/210/250 MW	300/330/350 MW	500 MW	600 MW and Above
2009-10	18.20	16.00	13.00	11.70
2010-11	19.24	16.92	13.75	12.37
2011-12	20.34	17.88	14.53	13.08
2012-13	21.51	18.91	15.36	13.82
2013-14	22.74	19.99	16.24	14.62

For thermal power stations with multiple units of the above sizes, the CERC has introduced the concept of reduction factor, which will apply to units commissioned after April 2009. The normative O&M expenses for the new units are determined by multiplying these factors with the normative O&M expenses detailed above.

Unit specification		Reduction Factor		Reduction Factor
200/210/250 MW	Additional 5th & 6th Unit	0.9	Additional 7th & more Unit	0.85
300/330/350 MW	Additional 4th & 5th Unit	0.9	Additional 6th & more Unit	0.85
500 MW and Above	Additional 3rd & 4th Unit	0.9	Additional 5th & above Unit	0.85

(f) Cost of Secondary Fuel Oil & Limestone

As per Tariff regulations for the period FY 2009-14, the CERC has included the cost of SFO as part of AFC. Projects are able to recover the cost of SFO on the basis of normative consumption norms specified by the regulator and the Plant Availability Factor during the year.

(g) Special Allowance In Lieu of R&M

The CERC in its previous regulations followed the policy of additional capitalisation arising out of any major renovation and modernisation (R&M) expenditure, whereby such capital expenditure was added to the previously approved gross block of the plant to determine the future tariffs. In its new regulations for the period 2009-14, the CERC has given an option to a coal based thermal power plants to avail of a special allowance as a part of AFC for meeting R&M expenses beyond the useful life of the power project. However in case the utility opts for this allowance as a part of AFC, there will be no increase in capital costs on account of capital expenditure incurred on R&M of power plant during the subsequent periods and no relaxed operational norms will be allowed for such projects. The allowance is available to the coal/lignite based thermal power project @ Rs 5 lakh/MW/Year from 2009-10 and is escalated @ 5.72% p.a.

4. <u>Energy Charges (for recovery of Primary fuel costs)</u>

Energy charges for thermal power stations are linked to the normative operational parameters as specified by the regulator. The normative parameters include the following:

Normative Operational Parameters for Coal based Thermal Power Projects

Norms for Operations		FY 2009-14
a	Plant Availability Factor	85%
b	Gross Station Heat Rate	
	For existing Stations	
	200/210/250 MW Sets	2500
	500 MW and above	2425
c	Secondary Fuel Oil Consumption	
	Coal Based	1.0 ml/Kwh
d	Auxillary Energy Consumption	
	200 MW Series	9.0%/8.5%
	500 MW Series (Steam driven BFP)	6.5%/6.0%
	500 MW Series (Power driven BFP)	9.0%/8.5%

5. Incentives linked to Plant Availability rather than Plant Load Factor

CERC in its Tariff Regulation for FY 2009-14, has linked incentives for Generating Station to the Plant Availability Factor (PAF) as opposed to Plant Load Factor (PLF) in its earlier Regulations for the period FY 2004-09.

The incentives will be recoverable as a part of the AFC and will be computed on monthly basis. The AFC inclusive of the incentive payable will be calculated as follows:

AFC (including incentive) = AFC x (Actual Plant Availability Factor/Normative Plant Availability Factor)

6. Other key highlights

(a) Billing and Payment

CERC has allowed the rebate of 2% for timely payment and billings supported by letter of credit (LC) and 1% for payment within one month. Late payment surcharge for payment beyond 60 days has also been retained at 1.25%.

(b) Sharing of CDM Benefits

The regulator has clarified the mechanism for sharing of benefits arising of the adoption of Clean Development Mechanism (CDM). The CDM benefits for the first year after Commercial

Operation can be retained by the project developer. During the second year, the developer would have to share 10% of the CDM benefits with the beneficiaries; the figure will progressively increase by 10% every year till it reaches 50%.

(c) Recovery of Hedging Costs and Foreign Exchange Rate Variation

The CERC has retained the policy of recovery of hedging cost and foreign exchange rate variation from the beneficiaries.

7. <u>General Concepts & Definitions in reference to Tariff determination</u>

(a) Auxiliary energy consumption

The quantum of energy consumed by auxiliary equipment of the generating station, and transformer losses within the generating station, expressed as a percentage of the sum of gross energy generated at the generator terminals of all the units of the generating station.

(b) Date of Commercial Operation' or 'COD'

The date declared by the generating company after demonstrating the maximum continuous rating (MCR) or the installed capacity (IC) through a successful trial run after notice to the beneficiaries, from 0000 hour of which scheduling process as per the Indian Electricity Grid Code (IEGC) is fully implemented, and in relation to the generating station as a whole, the date of commercial operation of the last unit or block of the generating station.

(c) Declared capacity

The capability to deliver ex-bus electricity in MW declared by such generating station in relation to any time-block of the day or whole of the day, duly taking into account the availability of fuel or water, and subject to further qualification in the relevant regulation.

(d) Gross calorific value

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.

(e) Gross station heat rate

The heat energy input in kCal required to generate one kWh of electrical energy at generator terminals of a thermal generating station.

(f) Infirm power

Electricity injected into the grid prior to the commercial operation of a unit or block of the generating station.

(g) Installed capacity

The summation of the name plate capacities of all the units of the generating station or the capacity of the generating station (reckoned at the generator terminals), approved by the Commission from time to time.

(h) Operation and maintenance expenses

The expenditure incurred on operation and maintenance of the project, or part thereof, and includes the expenditure on manpower, repairs, spares, consumables, insurance and overheads.

(i) Plant availability factor (PAF)

The average of the daily declared capacities (DCs) for all the days during that period expressed as a percentage of the installed capacity in MW reduced by the normative auxiliary energy consumption.

(j) Conversion of MW into Million Units (MUs)

$$1\text{ MW} = \frac{1\text{MW x 365days x 24hours x PLF x Availability Factor x 1000}}{1,0,00,000}$$

(k) Tariffs

- Nominal tariff
- Discount Tariff
- Levelized Tariff

Nominal Tariff:

The tariff calculated at for each year (fixed cost + variable cost)

Discount Tariff:

The tariff calculated at present value of the future tariffs. This is done by discounting future tariffs by discount rate (given by CERC)

Discount tariff= Nominal tariff x Discount factor

Levelized tariff:

The tariff calculated for all years. This is a simple tariff representing the tariffs throughout the plant life.

In concept, this is "Weighted Mean" of all tariffs with weights as discounting factors.

$$\text{Levelized Tariff} = \frac{\Sigma \text{ Nominal Tariff}_i \times \text{Discount Rate}_i}{\Sigma \text{ Discount Rate}_i}$$

where *i* varies from 1 to n.

n is the life of plant

Note:

1. The nominal tariff for the next year may be calculated by individually calculating for each year taking into consideration of future value of oil, coal etc.

2. Otherwise, we can escalate the nominal tariff for 1^{st} year taking appropriate escalation factors.

Tariff determination exercise for a 500 MW Thermal Power Plant

Given Data:

S No	Particulars	Normative Parameters
1	Capacity of Plant	500 MW
2	Capital Cost	4 Cr/MW
3	Debt Equity Ratio	70:30*
4	Return on Equity	15.5%*
5	Interest on Loan	10%
6	Working Capital (10% of Total Capital)	200 Cr
7	Interest on working Capital	10%
8	Depreciation Rate	5.28%*
9	Operation and Maintenance cost	13 Lakh/MW*
10	Plant Load Factor (PLF)	80%*
11	Plant Availability Factor	85%*
12	Specific Oil Consumption	10 ml/MW*
13	Price of Oil	Rs. 10,000/Kl
14	Gross Calorific value of Oil	10,000 Kcal/Lit
15	Station Heat Rate	2,425 Kcal/Lit*
16	Cost of Coal	Rs. 1000 / Tonnes
17	Auxiliary Power Consumption	6.50%*
18	Plant Life (For thermal plant based on Coal)	25 Years
19	Gross Calorific value of coal	4000 Kcal/Kg.

** Data as per CERC Tariff Regulations for FY 2009-14*

Calculations:

Fixed Cost Component calculations

(1) Return on equity

Capital cost/MW= Rs. 4 Cr

Capital cost for 500 MW = 500 x 4= Rs. 2,000 Cr.

Normative Debt/Equity Ratio= 70:30

Equity = 30/100 X 2000 = Rs. 600 Cr.

Debt =70/100 X 2000 = Rs. 1, 400 Cr.

RoE = 15.5% of Equity

15.5/100 x 600 = Rs. 93 Cr.

(2) Interest on Loan

10% of Debt=10 /100 x 1400 =Rs. 140 Cr.

(3) Interest on Working capital

10% of Working capital (Rs. 200 Cr.)

10/100 x 200 = Rs. 20 Cr.

(4) Depreciation

5.28% of Capital cost= 5.28/100 x 2000= Rs. 105.6 Cr.

(5) O & M Cost

Normative O&M Cost: Rs. 13 Lakhs/MW

For 500MW = 0.13 x 500= Rs. 65 Cr.

Hence, Total fixed cost = (1)+(2)+(3)+(4)+(5)

Rs. (93 + 140 + 20 + 105.6 + 65) = Rs. 423.6 Cr. = Rs. 423.6×10^7

$$500\text{ MW} = \frac{500 \times 365 \times 24 \times 80 \times 85 \times 1000}{10^6}$$

= 2978.4 Million Units (MUs)

$= 2978.4 \times 10^6$

Therefore, Fixed cost per unit

$=423.6 \times 10^7 / 2978.4 \times 10^6$

=Rs. 1.42 / kWh

Variable Cost Component calculations

Calculation of variable cost per unit:-

(1) Specific Oil consumption = 1 ml/kWh=1×10^{-3} l/kWh

(2) Cost of Specific Oil consumption = Specific Oil consumption x Cost of Oil/litre

$$= \text{Rs}\ \frac{1 \times 10^{-3} \text{ x lit x } 10000}{\text{kWh x lit}} = \text{Rs. } 0.01 \text{ / kWh}$$

(3) Heat contribution of oil:

= Gross calorific value of Oil x Specific Oil consumption

= 10,000 x KCal/litre x 1×10^{-3} litre/kWh = 10 Kcal/kWh

(4) Station Heat Rate

= Heat contribution of Oil + Heat contribution of Coal

Therefore, Heat contribution of Coal = Station Heat Rate – Heat contribution of Oil

= 2425-10 = 2415 Kcal/kWh

(5) Specific Coal consumption

$$= \frac{\text{Heat contribution of coal}}{\text{Gross calorific value of coal}}$$

= 2415/4000 = 0.60 Kg/KWh

(6) Cost of Specific Coal consumption

Specification Coal consumption x Cost of Coal

$$= \frac{0.60 \text{ Kg. x } 1000 \text{ Rs.}}{\text{kWh x Tonnes}}$$

$$\frac{0.60 \text{ Kg. x } 1000 \text{ Rs.}}{\text{kWh x } 1000 \text{ Kg.}} = 0.60 \text{ Rs/KWh}$$

Hence, Total Variable Cost per Unit:

= Cost of Specific Oil consumption + Cost of Specific Coal consumption

= Rs. (0.01 + 0.60) / kWh = Rs. 0.61 /kWh

Notes:

a) The variable cost calculated above is the variable cost of generation.

b) 6.5% of the Power generated is consumed in Auxiliary. So, in calculating Power available Ex-bus we have to subtract 6.5% of Available Power.

c) Variable cost per unit at bus bar $= \dfrac{\text{Variable cost per unit}}{1 - \text{\% Auxilliary consumption}}$

$$= \frac{0.61}{1 - 0.065} = \text{Rs } 0.65/\text{kWh}$$

Nominal Tariff calculation:

Nominal Tariff = (Total Fixed Cost / Unit) + (Total variable cost (Ex-bus)/Unit)

= Rs (1.42 + 0.65)/Unit = Rs. 2.07/Unit