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MINISTRY OF POWER

New Delhi, the , 1999

NOTIFICATION

S.O.------------------- In exercise of the powers conferred by sub-section (2) of section 43A of the Electricity (Supply) Act, 1948 (54 of 1948), herinafter referred to as the said Act, the Central Government hereby makes the following further amendments to the notification number S. O. 251(E),dated the 30th March, 1992 of the Government of India, the then Ministry of power and Non-Conventional Energy Sources laying down the factors in accordance with which the tariff for sale of electricity by the Generating Company to the Board and other persons shall be determined, namely:-

In the said notification:

The clause 1 shall be replaced by the following:-

1. **THERMAL POWER GENERATING STATIONS**

The two-part tariff for sale of electricity from Thermal Power Generating Stations shall comprise (a) the recovery of annual fixed charges consisting of interest on loan capital, depreciation, operation and maintenance expenses (excluding fuel), taxes on income reckoned as expenses, return on equity and interest on working capital at a normative level of generation, and (b) energy (variable) charges primarily covering the fuel cost recoverable for each unit (kiloWatt hour) of energy supplied and shall be based on the following norms :

1.1 **OPERATION NORMS**

The norms of Operation and Plant Load Factor as have been laid down by the Authority, for the time being, subject to modifications thereof, if any under sub-section (2) of section 43A of the said Act are as follows:

Notes (1) For abbreviations and definitions of various operating parameters refer Annexure A & B respectively.

(2) For Table of Contents refer to Annexure 'D'.

(3) The norms laid down by the Authority are the ceiling norms only and this shall not preclude the Boards and Generating Companies from agreeing to accept improved norms.

(4) Operation Norms have been laid down for Steam Power Stations (with and without Flue Gas Desulphurisation, Circulating Fluidized Bed Boilers), Combined Cycle Combustion Turbine (CCCT) Generating Stations and Diesel Generating Stations.

(5) These specified norms shall apply for new and unused Steam Power Stations, CCCT Generating stations and Diesel Engine Generating Stations for the entire plant life.

(6) The norms for CCCT are based on the assumption that all blocks consisting of heavy duty industrial type (other than aero-derivative type) combustion turbines, Generator(s), associated Waste Heat Recovery Boiler(s) and associated Steam Turbine - Generator and Auxiliaries, are identical.

(7) The norms do not take into account special requirements such as de-salination plant, sewage water treatment system and Selective Catalytic Reactor (SCR), which are site specifics. Further the norms for CCCT do not take into account inlet air cooling/heating system, the duct fring or steam injection for augmented power generation & LNG re-gassification Plant. The norms for D.G. sets do not take into account the flue gas de-sulphurisation (FGD) system.

(8) Operation norms specified hereunder for CCCT generating station are primarily for combined cycle operation. Combustion turbine simple cycle operation is not envisaged except for the period between COD of the first combustion turbine and synchronisation of steam turbine generator of the Block ; and also on specific requirement of the Regional Electricity Board under grid emergency conditions.

1.1.1 INSTALLED CAPCITY

1.1.1.1 Steam Power Station

The Installed Capacity of a Generating Station shall be the Rated Capacity or the sum of Demonstrated Capacity of Units in a generating station whichever is less and shall be maintained throughout the plant Life, provided that (a) the sum of Demonstrated Capacity of Units shall not fall short by more than 10.0 percent of the Rated Capacity, and (b) where the sum of the Demonstrated Capacity of Units falls short by less than or equal to 10.0 percent of the Rated Capacity, each of the debt and equity components of the capital cost of the project shall be reduced pro-rata. In case the shortfall in the capacity exceeds 10 percent of the Rated Capacity, the project shall stand rejected. In case the sum of the Demonstrated Capacity of Units is more than the Rated capacity, the Rated capacity shall be taken as the Installed Capacity.

1.1.1.2 Combined Cycle Combustion Turbine (CCCT) Generating Station

The Installed Capacity of a CCCT Generating Station for the first year of plant operation shall be the Rated Capacity or the sum of the Demonstrated Capacities of the Blocks, whichever is less. For subsequent years of plant operation, the Installed Capacity shall be determined by multiplying the first year Installed Capacity by Capacity Degradation Factor for the corresponding year as given hereunder.

YEAR OF OPERATION	CAPACITY DEGRADATION FACTOR	
	Natural Gas/ Liquefied Natural Gas (LNG)	Naphtha Natural Gas Liquid (NGL)
1.	1.0000	1.000
2.	0.9925	0.990
3.	0.9850	0.980
4.	0.9775	0.970
5.	0.9700	0.960
6.	0.9950	0.995
7.	0.9875	0.985
8.	0.9800	0.975
9.	0.9725	0.965
10.	0.9650	0.955
11.	0.9950	0.995
12.	0.9875	0.985
13.	0.9800	0.975
14.	0.9725	0.965
15.	0.9650	0.955

Explanation:

1. In case of dual fuel operation, the Installed Capacity shall be determined in proportion to heat input of the fuels used.

2. In case of dual fuel operation, the Capacity Degradation Factor in any year shall be determined based on the weighted average of the Capacity Degradation Factors for the corresponding year in proportion of the cumulative generation in the preceding years with respective fuels.

3. The sum of the Demonstrated Capacities of the Blocks shall not fall short by more than ten (10) percent of the Rated Capacity and where the sum of the

Demonstrated Capacities of the Blocks falls short by less than or equal to ten (10) percent of the Rated Capacity, each of the debt and equity components of the capital cost of the project shall be reduced pro-rata. In case the shortfall in the capacity exceeds ten (10) percent of the Rated Capacity, the project shall stand rejected. In case the sum of the Demonstrated Capacities of the Blocks is more than the Rated Capacity, the Rated Capacity shall be taken as the Installed Capacity for the first year of the plant operation.

1.1.1.3 Diesel Engine Generating Station

The Installed Capacity of the D.G. Generating Station shall be maintained at the level same throughout the plant life.

The sum of the Demonstrated capacities of the Units shall not fall short by more than 10 percent of the Rated Capacity and where the sum of the Demonstrated Capacities of the units falls short by less than or equal to 10 percent of the Rated Capacity, each of the debt and equity components of the capital cost of the project shall be reduced pro-rata of shortfall in capacity. In case the shortfall in the capacity exceeds 10 percent of the Rated Capacity, the project shall stand rejected. In case the sum of the Demonstrated Capacities is more than the Rated Capacity, the Rated Capacity shall be taken as the Installed Capacity.

1.1.2 PLANT LOAD FACTOR

1.1.2.1 Steam Power Station

1.1.2.1.1 Daily Plant Load Factor (DPLF)

The Daily Plant Load Factor (DPLF) shall not be less than 50 percent for the purpose of economic despatch of a Generating Station.

Note: (1) When any Unit is not available for the whole day, the daily PLF shall be calculated based on the number of Units in operation during the relevant day.

Note: (2) The DPLF shall be taken as the loading of the Generating Station for the purpose of determining the Daily Net Heat Rate or Daily Gross Heat Rate and Auxiliary Energy Consumption during the relevant day.

1.1.2.1.2 Annual Plant Load Factor (APLF)

The Annual Plant Load Factor shall not be less than 75.0 percent. In case of backing down, as ordered by the Regional Electricity Board, the Available

Capacity shall be reckoned as power generated and the Deemed Annual Plant Load Factor shall be the criterion for the purpose of determination of incentive, provided that the Available Capacity shall not exceed the Rated Capacity.

1.1.2.1.3 Deemed Annual Plant Load Factor (DAPLF)

The Deemed Annual Plant Load Factor shall be calculated as per the following formula :

$$\text{Deemed Annual plant Load Factor} = \frac{\text{Sum of Deemed Daily Plant Load Factors}}{365}$$

where the Deemed Daily Plant Load Factor (DDPLF) shall be determined by the following formula :

$$\text{DDPLF} = \frac{\text{Sum of Available Capacity for each Settlement Period of a day}}{\text{Installed Capacity x No. of Settlement Periods in the relevant day}}$$

1.1.2.2 Plant Load Factor for CCCT Generating Station

1.1.2.2.1 Settlement Period Plant Load Factor (SPLF)

The Settlement Period Plant Load Factor (SPLF) for CCCT Generating Station shall not be less than fifty (50) percent for the purpose of economic despatch.

Notes :

1. When any Block is not available for the whole settlement period, the SPLF shall be calculated based on the number of Blocks in operation during the relevant Settlement Period. When any Unit in a Block is not available for the whole Settlement Period, the SPLF shall be calculated after taking into account corresponding reduction in output of the Block.

2. When any Unit(s) operate(s) in simple cycle mode, the associated Block shall not be considered for determining SPLF of the Generating Station and the operational norms corresponding to simple cycle operation shall apply to such unit(s).
3. The SPLF shall be taken as the loading of the Generating Station for the purpose of determining the Net Heat Rate or Gross Heat Rate for the relevant Settlement period.

1.1.2.2.2 Annual Plant Load Factor (APLF)

The Annual Plant Load Factor shall not be less than seventy five (75) percent.

1.1.2.2.3 Deemed Annual Plant Load Factor (DAPLF)

For CCCT Generating Stations, the extent of backing down, as ordered by Regional Electricity Board shall be reckoned as power generated and the Deemed Annual Plant Load Factor (DAPLF) shall be calculated as per the following formula :

$$\text{DAPLF} = \frac{\text{Sum of Deemed Settlement Period Plant Load Factors}}{\text{Number of Settlement Periods in a year}}$$

Where, Deemed Settlement Period Plant Load Factor (DSPLF) shall be determined by the following formula :

$$\text{DSPLF} = \frac{\text{Available Capacity for a Settlement Period}}{\text{Installed Capacity}}$$

Note : For determination of DSPLF in case of dual fuel operation, the Available Capacity and Installed Capacity shall be the weighted average corresponding to the fuel mix for the Settlement Period.

1.1.2.3 Plant Load Factor for Diesel Engine Generating Station

1.1.2.3.1 Annual Plant Load Factor (APLF)

The Annual Plant Load Factor shall not be less than 75.0%.

1.1.2.3.2 Deemed Annual Plant Load Factor (DAPLF)

Deemed Annual Plant Load Factor shall be calculated as per the following formula :

$$\text{Deemed Annual Plant Load Factor} = \frac{\text{Sum of Deemed Daily Plant Load Factors}}{365}$$

where the Deemed Daily Plant Load Factor (DDPLF) shall be determined by the following formula :

Sum of Available Capacity for each settlement period of the day

DDPLF = ---
Installed Capacity x No. of settlement periods in a day

1.1.3 NET HEAT RATE OF A GENERATING STATION

The Net Heat Rate shall be determined as per formula given at Annexure 'B'under the following clauses:

(a) B- 1.12 for Steam Power Station
(b) B- 2.5.2 for CCCT Station
(c) B- 3.6.2 for Diesal Generating Station

1.1.4 GROSS HEAT RATE OF A GENERATING STATION

1.1.4.1 Steam Turbine Generator Cycle

The Gross Heat Rate of the Steam Turbine-Generator cycle shall be the relevant value as per following table.

Table : Gross Heat Rate for different loadings of Generating Station

	Steam Turbine Nominal Steam Parameter	Gross Heat Rate in kCal/kWh at loading of			
		100%	80%	60%	50%
i.	170 Kg / cm^2 (abs)/535°C/535°C	2000	2040	2100	2135
ii.	150 kg/cm^2 (abs)/535 °C/535°C	2040	2080	2140	2175
iii.	130 kg/cm^2(abs)/535 °C/535°C	2080	2120	2180	2215

Note : (a) The above specified Gross Heat Rate figures are for Turbine-Generator cycle with electric motor driven boiler feed pumps, and where steam turbine driven boiler feed pumps are used, the Gross Heat Rate shall be increased by 40kCal/kWh.

(b) The daily PLF shall be taken as the loading of the steam Turbine-Generator for the purpose of determination of Gross Heat Rate, for the relevant day.

(c) The Gross Heat Rate for any loading between any two above specified adjacent loadings shall be interpolated on pro-rata basis.

1.1.4.1.1 **Steam Generator Efficiency**

The Steam Generator Efficiency with coal or lignite or petroleum coke or vacuum residue fuels shall be determined by the following formula :

$$\text{Steam Generator Efficiency} = 92.5 - \frac{[\,50\,A + 630\,(M + 9\,H)]}{GCV}$$

Where, the Steam Generator Efficiency is based on GCV in percent.

'A' is the percentage ash content in the fuel,
'M' is the percentage moisture in the fuel and
'H' is the percentage hydrogen in the fuel.

Notes : (i) The values of "GCV', 'A', 'M', and 'H' correspond to as fired basis.

(ii) The 'GCV' value 'as received' basis shall be reduced by 100kCal/kg and the value of 'M' increased by one percent to take into account heat lost between coal ‘as received’ and ‘as fired’ basis.

(iii) The values of 'GCV', 'A', 'M', and 'H' are the weighted average of all the consignments received during the month.

(iv) The Steam Generator Efficiency based on GCV with 'Corex' gas from steel industry shall not be less than 87.5 percent.

(v) Where a combination of fuels is used, the Steam Generator Efficiency shall be the weighted average figures based on the percentage of the fuels used.

1.1.4.2 Gross Heat Rate for a CCCT Generating Station

1.1.4.2.1 Combined Cycle Opertion

The Gross Heat Rate of the CCCT Block or Generating Station using Natural Gas/ Liquefied Natural Gas (LNG) as fuel at standard reference conditions as per the latest versions of ISO - 2314 and ISO 3977 shall be the relevant value as per the following table :

Table : Gross Heat Rate for different loadings of CCCT Generating Station

Categorisation based on ISO base rating of a Combustion Turbine (in simple cycle mode with Natural Gas/LNG as fuel) in the CCCT Block	Gross Heat Rate of CCCT Generating Station in kCal/kWh at loading of			
	100%	80%	60%	50%
i. 50 MW and less	1800	1850	1980	2080
ii. More than 50 MW and less than 200 MW	1680	1730	1850	1950
iii. 200 MW and above	1580	1630	1740	1840

Notes:

1. In case of CCCT Generating Stations using Naphtha/ Natural Gas Liquid (NGL) as fuel, the above specified Gross Heat Rate figures shall be multiplied by a factor of 1.02.

2. In case of CCCT Generating Stations using conventional combustor (other than dry low NOx) and steam / water injection for NOx control, Gross Heat Rate shall be increased as under :

Fuel	Natural Gas/LNG	Naphtha /NGL
NOx Emission Level	50 ppm	100 ppm
Max. heat rate Degradation, In kCal/kWh, with		
i) Water injection	100	50
ii) Steam injection	75	35

In case NOx emission levels stipulated in Environmental Clearance are different from the above values, the heat rate degradation applicable shall be determined in proportion of the ratio of above stated NOx levels to the NOx levels stipulated in Environmental Clearance.

If dry low NOx combustors are used in conjunction with water/steam injection, corresponding adjustment in heat rate shall be based on manufacturer's guarantees.

3) For the purpose of determination of Gross Heat Rate for the relevant Settlement Period, the SPLF shall be taken as the loading of the CCCT Generating Station.

4) Gross Heat Rate for any loading between any two above specified adjacent loadings shall be interpolated on pro-rata basis.

1.1.4.2.2 Simple Cycle Operation

The Gross Heat Rate of the Unit(s) in simple cycle mode of operation using Natural Gas/LNG as fuel at standard reference conditions as per the latest version of ISO-2314 shall be the relevant value as per following table:

Table : Gross Heat Rate for different loading of Unit(s)

	Categorisation based on ISO based rating of Combustion Turbine (in Simple cycle mode with Natural Gas/LNG as fuel)	Gross Heat Rate in kCal/kWh at loading of		
		100%	80%	60%
1.	50 MW and less	2800	2950	3175
2.	More than 50 MW and less than 200 MW	2600	2750	2975
3.	200 MW and above	2400	2550	2775

Notes :

1. In case of Unit(s) using Naphtha/NGL as fuel, the above specified Gross Heat Rate figures shall be multiplied by a factor of 1.01.

2. In case of Unit(s) using conventional combustor (other than dry low NOx) and water injection for NOx control, Gross Heat Rate shall be increased as under :

Fuel **NOx Emission Level**	**Natural Gas/LNG** **50 ppm**	**Naphtha /NGL** **100 ppm**
Max. heat rate degradation, In kCal/kWh, with Water injection	70	50

In case NOx emission levels stipulated in Environmental Clearance are different from the above values, the heat rate degradation applicable shall be changed in proportion of the ratio of above stated NOx levels to the NOx levels stipulated in Environmental Clearance.

If dry low NOx combustors are used in conjunction with water injection, corresponding adjustment in heat rate shall be mutually agreed based on manufacturer's guarantees.

3) For the purpose of determination of Gross Heat Rate for the Settlement Period, average loading of the Unit during the Settlement Period shall be taken as the loading of the Unit.

4) Gross Heat Rate for any loading between any two above specified adjacent loadings shall be interpolated on pro-rata basis.

1.1.4.3 Diesel Generating Station

The Gross Heat Rate of the Diesel Generating Unit at standard reference conditions as per the latest version of ISO - 3046 shall be (a) the following values or (b) guaranteed heat rate corresponding to MCR, whichever is less :

Type of D.G. Engine	Gross Heat Rate in kCal/kWh
i. Medium speed 4 - stroke	2000
ii. Low speed 2 - stroke	1900

Note : The Gross heat rate indicated above shall remain applicable for various loading conditions of the station. Generally, the heat rate of DG unit does not vary significantly between 70% and 100%. In case, station load comes down to 70% or less, some D.G. unit(s) can be shut down maintaining higher loading of the working DG sets.

1.1.5 AUXILIARY ENERGY CONSUMPTION

1.1.5.1 Steam Power Station

The Auxiliary Energy Consumption of the Generating Stations at the Rated Capacity with electric motor driven Boiler Feed Pumps (BFPs) shall not exceed the following values :

Type of Steam Generator/Fuel		Auxiliary Energy consumption in percentage	
		with once-through water cooling	with closed cycle cooling using wet cooling tower
Conventional Steam Generator			
(i)	Domestic run of mine coal/ Lignite	8.5	9.0
(ii)	Domestic beneficiated coal	8.0	8.5
(iii)	Imported beneficiated coal/ Petroleum coke/Vacuum residue	7.5	8.0
(iv)	Corex gas	6.5	7.0

Note : The Auxiliary Energy Consumption of Generating Stations with Steam Turbine driven boiler feed pumps shall be reduced by 1.5 percent.

1.1.5.1.1 Post Combustion Desulphurisation System

The following values shall be added to auxiliary power consumption as specified at para 1.1.5.1 for Conventional Steam Generator with flue Gas Desulphurisation System :

Process	Maximum Additional Auxiliary Energy Consumption (%)
Wet Limestone Process	1.5
Spray Dryer Process	1.0

1.1.5.1.2 In- Combustion Desulphurisation System :

The Auxiliary Energy Consumption of the Generating Station with Circulating Fluidised Bed Combustion Steam Generators at the Rated Capacity with electric motor driven Bioler Feed Pumps (BFPs) shall not exceed the following values.

	with once through water	with closed cycle cooling using wet cooling tower

		cooling	
a)	High Sulphur coals (Sulphur content greater than 1%)	10.5%	11.0%
b)	Domestic coal washery rejects	10.5%	11.0%
c)	Imported beneficiated coal/ Petroleum coke/Vacuum residue	9.5%	10.0%

1.1.5.1.3 Part Load Operation

The Auxiliary Energy Consumption at part load operation of the Generating Station shall be calculated by multiplying the above specified figures by the following multiplying factors :

DPLF	Multiplying Factor
100%	1.00
80%	1.08
60%	1.20
50%	1.30

Note : For sample calculation of coal and secondary oil consumption refer Annexure C.

1.1.5.2 CCCT Generating Station

1.1.5.2.1 Combined Cycle Operation

The Auxiliary Energy Consumption (in percentage) of CCCT Generating Station shall not exceed the following values :

	Fuel	Auxiliary Energy Consumption (%)	
		With once-through water cooling system	Using wet cooling tower system
i.	Natural Gas/LNG		
a.	Without water/steam injection	2.50	2.75
b.	with water/steam injection	2.60	2.85
ii.	Naphtha/NGL (with water/ steam injection)	2.75	3.00

1.1.5.2.2 **Simple Cycle Operation**

The Auxiliary Energy Consumption (in percentage) of Unit(s) operating in simple cycle mode shall not exceed the following values :

	Fuel	Auxiliary Energy Consumption (%)
ii.	Natural Gas/LNG :	
a)	without water injection	1.25
b)	with water injection	1.35
ii.	Naphtha/NGL (with water injection)	1.50

Note 1 In case of dual fuel operation, the AEC shall be determined in proportion to the heat input of the fuels used

Note 2 For sample calculation of Fuel consumption for CCCT plant refer Annexure C

1.1.5.3 Diesel Generating Station

The Auxiliary Energy Consumption of Generating Stations shall not exceed the following values:

Type of D.G. Engine		Auxiliary Energy consumption in percentage	
		with radiator cooling	using wet cooling tower
a)	Medium speed 4-stroke	4.5	4.0
b)	Low speed 2- stroke	3.5	3.0

1.1.6 SPECIFIC SECONDARY FUEL OIL CONSUMPTION

1.1.6.1 Steam Power Station

The Specific Secondary Fuel Oil Consumption for the purpose of start up-shut down and flame stabilisation shall not exceed the following values:

Type of Fuel		Specific Secondary Fuel Oil Consumption in ml/gross kWh
a)	All type of coals, Petroleum coke and Vacuum residue	1.0
b)	Lignite	3.0

Note : While calculating the consumption of primary fuel, the heat credit for the secondary fuel consumption at the above specified rate shall be given.

1.1.7 SPECIFIC REAGENT CONSUMPTION

1.1.7.1 In-combustion Desulphurisation System

Specific Reagent Consumption, for Steam Generator Turbine Generating station with Circulating Fluidised Bed Combustion (CFBC) type Steam-Generator shall be a) guaranteed Specific Reagent Consumption or b) the value determined by the following formula, whichever is less :

Fuel	Reagent	Specific Reagent Consumption kg/kg of fuel consumption
High Sulphur Coal/Lignite	Limestone	$\frac{6.25}{P} \times S$
Petcoke/ Vacuum Residue	Limestone	$\frac{7.8}{P} \times S$

Where, S is percentage sulphur content in primary fuel
P is percentage purity of reagent

1.1.7.2 Post-combustion Desulphurisation System

Specific Reagent Consumption for Steam Power Stations with Flue Gas Desulphurization Sytem shall be a) guaranteed Specific Reagent Consumption or b) the value determined by the following formula, whichever is less:

Process	Reagent	Sulphur Dioxide Removal Efficiency	Specific Reagent Consumption kg/kg of fuel consumption
Wet Limestone Process	Limestone	90% and more	$\frac{3.28}{P} \times S$
Spray Dryer Absorber Process	Lime	70% & more but less than 80%	$\frac{2.19}{P} \times S$
		80% & more but less than 90%	$\frac{2.45}{P} \times S$
		90% and more	$\frac{2.8}{} \times S$

P

Where, S is percentage sulphur content in the fuel.

P is percentage purity of reagent.

1.1.8 LUBRICATING OIL CONSUMPTION

1.1.8.1 Diesel Generating Station

Lubricating Oil Consumption shall not exceed the following values :

Type of D.G. Engine		Lubricating Oil (incl. cylinder oil) Consumption in g/kWh (gross)
a)	Medium speed 4-stroke	1.0
b)	Low speed 2-stroke	1.2

1.1.9 'COMMERCIAL OPERATION DATE' OR 'COD'

1.1.9.1 Seam Power Station

Commercial Operation Date' or 'COD' - In relation to a Unit, date by which the Maximum Continuos Rating (MCR) or acceptable Installed Capacity is demonstrated by a Performance Acceptance Test as per international codes, after successful trial operation including stabilisation. The COD of the Generating Station shall be reckoned from the COD of the last unit.

Explanation:

For energy generated upto COD of the Unit, fuel charges shall be payable to the Generating Companies as per actuals.

1.1.9.2 Combined Cycle Combustion Turbine (CCCT) Generating Station

‘Commercial Operation Date' or 'COD' - In relation to a Unit or Block, date on which Maximum Continuos Rating (MCR) or acceptable Installed Capacity is demonstrated by Performance Acceptance Test as per latest versions of ISO -2314/ASME PTC-22 for Combustion Turbine and ASME PTC-6 for Steam Turbine after successful trial operation including stabilisation. The COD of the Generating Station shall be reckoned from the COD of the last Block.

Explanation:

1. Till COD of a Unit, fuel charges shall be payable to Generating company as per actuals. On declaration of COD of the Unit, fuel charges shall be determined as per operation norms for simple cycle operation.

2. As and when the steam turbine generator is synchronised with the grid, the fuel charges for the Block shall be payable to the Generating company as per actuals till COD of the Block. After COD of the Block, the fuel charges shall be determined as per operation norms for combined cycle operation.

3. Till COD of the Generating Station, the fixed charges shall be payable corresponding to the capital cost of unit(s)/ Block(s) in Commercial Operation.

1.1.9.3 Diesel Engine Generating Station

‘Commercial Operation Date' or 'COD' - In relation to a Unit, date on which the Maximum Continuous Rating (MCR) or acceptable Installed Capacity is demonstrated by a Performance Acceptance Test as per latest versions of ISO - 3046 for Diesel Engine and IS : 4722, IS : 5422 & IS : 7132 and IEC-34 for Generator after successful trial operation including stablisation. The COD of the Generating Station shall be reckoned from the COD of the last Unit.

Explanation: For energy generated upto COD of the Unit, fuel charges shall be payable to the Generating Company as per actuals.

1.2 FINANCIAL PARAMETERS

1.2.1 Capital Expenditure

The capital expenditure of the project shall be financed as per the approved financial package set out in the techno-economic clearance of the Authority. The project cost shall include capitalised initial spares. The approved project cost shall be the cost which has been specified in the techno-economic clearance of the Authority.

The actual capital expenditure incurred on completion of the project shall be the criterion for the fixation of tariff. Where the actual expenditure exceeds the approved project cost the excesses as approved by the Authority shall be deemed to be included in the approved project cost for the purpose of determining the tariff:

Provided that such excess expenditure is not attributable to the Generating Company or its suppliers or contractors.

Provided further that where a Power Purchase Agreement entered between the Generating Company and the Board provides ceiling on capital expenditure, the capital expenditure shall not exceed such ceiling.

Provided also that in case of multi-unit project, the percentage of capital cost as specified by the Authority in its techno-economic clearance shall be considered for fixation of tariff, on commercial operation of the progressive units but in case of delay in commissioning of the second or subsequent units from the scheduled date, the project cost, for the period of delay, shall be retrospectively considered for the tariff purpose in the ratio of proportionate allocation of units.

Provided further that if the capital cost of the project increases, in comparison to the cost approved in the techno-economic clearance, on account of foreign exchange variation or change of law or any other reason not attributable to the Generating Company or its suppliers or contractors and approved by the Competent Government, the project developer may approach the Authority with the recommendation of the Competent Government, not more than once in a financial year, for the mid-term review of the Capital Cost.

Provided further that the Authority may, for special reasons to be specified by the project developer, allow the mid term review of Capital Cost more than once in a financial year.

1.2.2 Fixed Charges

The annual fixed charges shall be computed on the following basis:

1.2.2.1 Interest on loan capital shall be computed on the outstanding loans, including the schedule of repayment, as per the financial package approved by the Authority.

Note: (1) In case a generating company takes land on lease, the leasing charges as determined by the Central Government or the State Government or any statutory body, as the case may be considered as a pass through item in the tariff in lieu of interest liability of the notional cost of the land.

(2) Extra rupee liability towards interest payment and loan repayment actually incurred, in the relevant year shall be admissible, provided it directly arises out of foreign exchange rate variation and is not attributable to Generating Company or its suppliers or contractors.

1.2.2.2 The rates of depreciation shall be applicable as notified by Central government, from time to time.

1.2.2.3 Operation and Maintenance (O&M) Expenses :

1.2.2.3.1 Steam Power Stations

The annual Operation and Maintenance (O&M) expenses after the commercial Operation Date of the last Unit shall be determined as per the following formula :

$C\ (O\&M)_n = 0.025 \times CC\ (0.7\ WP_n/WP_1 + 0.3\ CP_n/CP_1)$

Where,

$C\ (O\&M)_n$ is the annual Operation & Maintenance expenses in crores of Rupees for the nth year of operation

CC is the actual capital expenditure in crores of Rupees as provided in clause 1.2.1

WP_n is the wholesale price index during the nth year, and

CP_n is the consumer price index during the nth year.

Note (1) Upto the Commercial Operation Date of the last Unit, the O&M Expenses for Units(s) in commercial operation shall be allowed in proportion to the allocation of the capital cost to the respective Unit as set out in the techno-economic clearance of the CEA or clearance of the competent authority approved by the State Government or the Power Purchase Agreement, as the case may be.

(2) No escalation in O&M Expenses shall be allowed upto one year from the COD of the last Unit of the Generating Station.

1.2.2.3.2 Combined Cycle Combustion Turbine (CCCT) Station

The annual Operation and Maintenance (O&M) expenses after the Commercial Operation Date (COD) of the last Block shall be determined as per the following formula:

$C\ (O\&M)_n = 0.025*CC*\ (0.7\ WP_n/WP_1 + 0.3\ CPn/CP_1)$

Where, $C(O\&M)_n$ is the annual Operation & Maintenance expenses in crores of Rupees for the nth year,

CC is the actual capital expenditure crores of Rupees as provided in Clause 1.2.1

WP_n is the wholesale price index during the nth year, and

CP_n is the consumer price index during the nth year.

Note : (1) Upto the Commercial Operation Date of the last Block, the O&M Expenses for Units/Blocks in commercial operation shall be allowed in proportion to the allocation of the capital cost to the respective Units/Blocks as set out in the techno-economic clearance of the CEA or clearance of the competent authority approved by the State Government.

(2) No escalation in O&M Expenses shall be allowed upto one year form the COD of the Generating Station.

1.2.2.3.3 Diesel Engine Generating Station

The annual Operation & Maintenance (O&M) expenses after the Commercial Operation Date of the last Unit shall be determined as per the following formula :

$$C(O\&M)_n = OMP*CC\ (0.7\ WP_n/WP_1 + 0.3\ CP_n/CP_1)$$

Where, $C(O\&M)_n$ is the annual Operation & Maintenance expenses in cores of Rupees for the nth year,

OMP is O&M percentage factor being 0.04 for plant based on medium speed 4-stroke D.G. engines and 0.025 for plant based on low speed 2 stroke D.G. engines.

CC is the the actual capital expenditure crores of Rupees as provided in clause 1.2..1

WP_n is the wholesale price index during the nth year, and

CP_n is the consumer price index during the nth year.

Note : (1) Upto the Commercial Operation Date of the last Unit, the O&M Expenses for Units in commercial operation shall be allowed in proportion to the allocation of the capital cost to the respective Unit as set out in the techno-economic clearance of the CEA or clearance of the competent authority approved by the State Government.

(2) No escalation in O&M Expenses shall be allowed upto one year from the COD of the Generating Station.

1.2.2.4 Tax On Income

Tax on the following income streams, if any, of the Generating Company to be computed as an expense at actuals:-

i) Sixteen per cent return on equity;

ii) The extra rupee liability on account of foreign exchange rate variation in computing the return on equity not exceeding 16 per cent in the currency of the subscribed capital;

iii) The amount of grossed up tax that is payable and actually paid by the generating company under income streams mentioned at items (i) and (ii);

Any under or over recoveries of tax shall be adjusted every year on the basis of a certificate of statutory auditors.

Note: Tax on other income streams, if any, accruing to the Generating Company shall not constitute a pass through component in the tariff. Tax on such other incomes shall be payable by the Generating Company.

1.2.2.5 Return On Equity

Return on equity shall be computed on the paid up and subscribed capital relatable to the generating unit, and shall be 16 per cent of such capital.

Explanation - I : For the purpose of this paragraph, the Generating Company shall, in regard to subscribed equity brought in foreign exchange, have the option to compute the return on equity not exceeding 16 per cent in the currency of the subscribed capital.

Explanation - II : Premium raised by the Generating Company while issuing share capital and investment or internal resources created out of free reserve of existing company, if any, for the funding of the project, shall also be reckoned as paid up capital for the purpose of computing the return on equity, provided such premium amount and internal resources are actually utilised for meeting the capital expenditure of the power generation project and forms part of the approved financial package as set out in the techno-economic clearance accorded by the Authority.

1.2.2.6 Interest on working capital

1.2.2.6.1 Steam Power Station

For the purpose of calculations of interest on working capital, the working capital shall not exceed the following :

(a) One and half months' expenses of the following items :

i. Primary fuel consumption - coal, lignite or petroleum coke or vacuum residue at 75% PLF.

ii. Secondary fuel oil consumption at 75% PLF.

iii. Annual O&M Expenses.

(b) Expenses of the following items of stock :

i. half a month's consumption of primary fuel in case the source of fuel is within 100 km from the Generating Station or one month's consumption of primary fuel for other Stations at Rated Capacity.

ii. half a month’s consumption of secondary fuel oil at Rated Capacity.

iii. One year maintenance spares at 40 percent of annual O&M Expenses.

Note (i) Consumption of fuels shall be calculated as per relevant operation norms.

(ii) In case the source of primary fuel-coal or lignite linked mine or oil refinery in case of petroleum coke or vaccum residue is located within 100 km from the Generating Station, it shall be treated as pit-head station.

(iii) In respect of one year maintenance spares, for each of the first 3 years of operation of the station, one third of capitalised spares cost shall be deducted form the cost of one year maintenance spares.

(iv) In case the due date of payment of monthly bill is less than 15 days as per Power Purchase Agreement, the one and a half month’s expenses specified at item (a) above shall be limited to (30+n) days, where n is the number of days for due payment of monthly bill.

1.2.2.6.2 Combined Cycle Combustion Turbine (CCCT) Station

For the purpose of calculation of interest on Working Capital, the Working Capital in respect of operational parameters shall not exceed the following :

(a) One and half months' expenses of the following items :

(i) Fuel consumption at 75% PLF.

(ii) Annual O&M Expenses.

(b) Expenses of the following items of stock :

(i) half a month's consumption of fuel at 75% of Installed Capacity in case of CCCT generating station using Naphtha /NGL.

(ii) One year maintenance spares at 40% of annual O&M

Note: (1) Consumption of fuel shall be calculated as per relevant operation norms.

(2) In respect of one year maintenance spares, for each of the first 3 years of operation of the station, one third of capitalised spares cost shall be deducted from the cost of one year maintenance spares.

(3) In case the due date of payment of monthly bill is less than 15 days as per Power Purchase Agreement, the one and half months expenses specified at item (a) above shall be limited to (30 +n) days expenses where 'n' is the number of days for due payment of monthly bills.

1.2.2.6.3 Diesel Engine Generating Station

For the purpose of calculation of interest on working capital, the working capital in respect of operational parameters shall not exceed the following :

a) One and half months' expenses of the following items :

(i) Fuel consumption at 75.0% PLF.

(ii) Lubricating oil including cylinder oil consumption at 75.0% PLF.

(iii) Annual O&M Expenses.

b) Expenses of the following items of stock :

i) half a month's consumption of fuel at 75.0% of installed capacity.

ii) Half a month consumption of lubricating oil including cylinder oil at 75.0% of Installed capacity.

iii) One year maintenance spares at 40 percent of annual O&M Expenses.

Note : (i) Consumption of fuel and lubricating oil including cylinder oil shall be calculated as per relevant operation norms.

(ii) In respect of one year maintenance spares, for each of the first 3 years of operation of the station, one third of capitalised spares cost shall be deducted from the cost of one year maintenance spares.

(iii) In case the due date of payment of monthly bill is less than 15 days as per Power Purchase Agreement, the one and a half months expenses specified at item (a) above shall be limited to (30+n) days expenses where 'n' is the number of days for due payment of monthly bills.

1.2.3 Incentive

Full fixed charges shall be recoverable at generation level of 75% Annual P.L.F. Payment of fixed charges below the level of 75% Annual P.L.F. shall be on prorata basis. There shall not be any payment for fixed charges for generation level above 75 % Annual P.L.F. For generation of above 75% Annual P.L.F., the additional incentive payable shall not exceed 0.7 percent of paid up and subscribed capital, for each percentage point increase of Plant Load Factor above the normative level of 75% PLF. While computing level of generation, the extent of backing down, as ordered by the Regional Electricity Boards or State Load Despatch Center, as the case may be shall be reckoned as generation achieved. The payment of fixed charges shall be on monthly basis, proportionate to the electricity drawn by the respective Boards and other persons. Necessary adjustment based on actual shall be made at the end of each year.

Note: 1. The additional incentive of return on equity of 0.7 percent for each percentage increase above the normative level of 75% Annual PLF mentioned above shall be the maximum ceiling. It shall be open to the Generating Companies and Boards or other Power Purchasers to negotiate and fix a suitable lower additional incentive, within the above ceiling.

Note: 2 For Naphtha/NGL based CCCT plants and Diesel Engine Genrating Units the extent of backing down, as ordered by Regional Electricity Boards or the State Load Despatch Center, as the case may be, beyond Plant Load Factor of 75% Annual P.L.F. shall not be reckoned as generation achieved for purposes of incentive.

1.2.4 Energy (Variable) Charges

1.2.4.1 Energy (variable) charges shall cover generally fuel costs and its charges per kWh of energy supplies shall be computed based on landed cost of fuel, its calorific value and the following parameters subject to the stipulation of note (3) under Clause 1.1 :

(a) **Primary Fuel** : Specific fuel comsumption based on the net heat rate formulae at as per clause 1.1.3 and calorific value of fuel.

(b) **Secondary Fuel Oil** : (for steam power stations only) Specific secondlary oil consumption as per clause 1.1.6 and Auxiliary Energy Consumption at cluase 1.1.5.

In addition, the energy charges shall take into account following additional component where applicable.

(a) **Lubricating Oil:** Specific lubricating oil consumption as per clause

	(for Diesel Geneating Station only)	1.1.8 and Auxiliary Energy Consumption as per clause 1.1.5.3
(b)	**For Desulphurisation** : **system** if installed and operated.	Specific reagent consumption as per cluase 1.1.7 and Auxiliary Energy Consumption as per clause 1.1.5.

1.2.4.2 Adjustment on account of variation in price or quality

Initially the relevant Calorific Value of the fuel shall be taken as per actuals in the preceding three months. Any variation shall be adjusted on a month to month basis on the basis of the relevant Calorific Value of the fuel actually received and burnt and actual landed cost incurred by the Generating Company for procurement of the fuel. This method shall be adopted for the determination of the additional charges for the reagents for Desulfurisation and for the lubricating oil for diesel generating stations.

ANNEXURE - A

ABBREVIATIONS

A-1. Units :

(a)	°C	-	degree Celsius
(b)	Hz	-	Hertz or cycles per second
(c)	kCal	-	kilo- Calorie
(d)	g	-	gram
(e)	kg	-	kilogram
(f)	kg/cm^2 (abs)	-	kilogram per square centimeter (absolute)
(g)	kW	-	kilo Watt
(h)	kWh	-	kilo Watt hour
(i)	l	-	litre
(j)	ml	-	milli litre
(k)	Sm^3	-	cubic metre of gas at Standard temperature and pressure, namely 15 °C and 1.03 kg/cm^2 (absolute)

A-2 Defined /Derived

AEC	-	Auxiliary Energy Consumption
APLF	-	Annual Plant Load Factor
ASME	-	American Society of Mech. Engineers
CEA/Authority	-	Central Electricity Authority
COD	-	Commercial Operation Date
CCCT	-	Combined Cycle Combustion Turbine
CFBC	-	Circulating Fluidized Bed Combustion
DG	-	Diesel Generator / Generating
DPLF	-	Daily Plant Load Factor
DAPLF	-	Deemed Annual Plant Load Factor
DNHR	-	Daily Average Net Heat Rate
DSPLF	-	Deemed Settlement Period Plant Load Factor
GCV	-	Gross Calorific Value
GHR	-	Gross Heat Rate
IEC	-	International Electro-Technical Commission
ISO	-	International Standards Organisation
LNG	-	Liquefied Natural Gas
MCR	-	Maximum Continuous Rating
MNHR	-	Monthly Average Net Heat Rate
NCV	-	Net Calorific Value
NGL	-	Natural Gas liquid
NHR	-	Net Heat Rate
SPLF	-	Settlement Period Plant Load Factor
SGE	-	Steam Generator Efficiency
SNHR	-	Settlement Period Net Heat Rate

ANNEXURE-B

DEFINITIONS

B-1 Steam Power Station

B-1.1 ‘**Auxiliary Energy Consumption’** - In relation to any period, the ratio, expressed as a percentage, of

(a) gross energy in kwh generated at Generator terminals minus net energy in kwh delivered at the Generating Station Switchyard

to

(b) gross energy in kwh generated at the Generator terminals.

B-1.2 ‘**Available Capacity**’ - In relation to Settlement Period, the sum of

(a) Power delivered or deemed to be delivered (in case of backing down) at the switchyard

and

(b) Auxiliary power consumption,

Explanation (1) : Auxiliary power consumption shall be the average value based on Auxiliary Energy Consumption at the PLF or deemed PLF during the Settlement period.

Explanation (2) : The available capacity shall not exceed the Installed Capacity

B-1.3 ‘**Commercial Operation Date’ or ‘COD**’ - In relation to a Unit, date by which the Maximum Continuos Rating (MCR) or acceptable installed capacity is demonstrated by a Performance Acceptance Test as per international codes, after successful trial operation including stabilisation. The COD of the Generating Station shall be reckoned from the COD of the last Unit.

B-1.4 ‘**Deemed Plant Load Factor**’ – In relation to any period of operation of the Generating Station, the ratio, expressed as a percentage, of

a) The sum of Available Capacity for each Settlement Period

to

b) Installed Capacity multiplied by the number of Settlement Periods

B-1.5 ‘ **Demonstrated Capacity’ –** In relation to a Unit, the electric output at Generator terminals demonstrated at rated parameters during Performance

Acceptance Test as per international codes such as ASME PCT 6, after successful trial operation including stabilisation.

Explanation: The Demonstrated Capacity shall be corrected for 47.5 Hz grid frequency and worst circulating water inlet temperature for the purpose of arriving at the Installed Capacity.

B-1.6 ' **Generating Station**' - Unit and balance of plant

B-1.7 ' **Gross calorific Value**' or **'GCV' -** The heat produced in kCal by complete combustion of one kg. of solid fuel or liquid fuel or one standard cubic metre (Sm^3) of gaseous fuel, as per IS: 1350 (Part-II) or IS:1448 (P : 6) as the case may be.

Explanation : In case of coal or lignite fuel, the GCV of the fuel as received shall be reduced by 100 kCal/kg to arrive at the GCV of the fuel as fired for the purpose of determination of the fuel consumption

B-1.8 ' **Gross Heat Rate' or 'GHR'** - The heat energy in kCal input to Turbine **–** Generator cycle to generate one kwh of electric energy at Generator terminals.

B-1.9 ' **Installed Capacity**' - In relation to a Generating Station, Rated Capacity or sum of the Demonstrated Capacity of the Units in the Generating Station, whichever is less.

Explanation : Installed Capacity shall be maintained down to 47.5 Hertz (Hz) grid frequency, with worst circulating water inlet temperature and with worst fuel.

B-1.10 '**Maximum Continuous Rating' or 'MCR'**- In relation to a Unit, the maximum Continuous output at the Generator terminals, guaranteed by the manufacturers at rated parameters as per IEC-45

Explanation : MCR shall be maintained down to 47.5 Hertz (Hz) grid frequency, with worst circulating water inlet temperature and with worst fuel.

B-1.11 '**Net calorific Value' or NCV –** Gross Calorific Value minus the heat loss due to total moisture in complete combustion of one kilogram of solid fuel or liquid fuel or one standard cubic metre of gaseous fuel, expressed in kCal/kg or Sm^3

B-1.12 ' **Net Heat Rate' or 'NHR' –** The heat energy in kCal, input to a Generating Station to deliver one Kwh at the switchyard .

B-1.12.1 ' **Net Heat Rate Formulations'**

The daily Net Heat Rate at any loading of the Generating Station shall be (a) guaranteed Net Heat Rate corresponding to the loading of the Generating Station multiplied by 1.05 or (b) the value determined by the following formulae, whichever is less

$$DNHR = \frac{GHR \times 100}{100\text{-}AEC} \times \frac{100}{SGE}$$

Where, DNHR is the Net Heat Rate of the Generating Station during a day in Kcal/Kwh,

GHR is the Gross Heat Rate of the Turbine Generator Cycle in kCal/kWh corresponding to the loading of the Turbine-Generator during the relevant day, as per para 1.1.4.1 of Operation Norms

SGE is the Steam Generator Efficiency expressed in percentage , as per para 1.1.4.1.1 of Operation Norms.

AEC is the Auxiliary Energy Consumption, corresponding to the loading of the Turbine Generator during the relevant day, expressed in percentage, as per para 1.1.4.1 of Operation Norms.

The monthly average Net Heat Rate shall be calculated by weighted average as per the following formula :

$$MNHR = \frac{\text{Sum of (DNHR x NkWh) during the month}}{\text{Sum of NkWh during the month}}$$

Where, MNHR is the monthly average Net Heat Rate in kCal/kWh,
DNHR is the Net Heat Rate for a day in kCal/kWh
NkWh is the net kWh delivered at the switchyard during the relevant day

Note (1) : The guaranteed Net Heat Rate shall be at design cooling water inlet temperature corresponding to 90% duration and adjustment for ash, moisture and hydrogen content of primary fuel, except for Corex gas.

Note (2) : In case the guaranteed Net Heat Rate is not available , the Net heat Rate shall be determined based on guaranteed Gross Heat Rate of Steam Turbine - Generator Cycle at design cooling water inlet temperature corresponding to 90% duration, guaranteed Steam Generator Efficiency with adjustment for ash, moisture and hydrogen content except for Corex gas and Auxiliary Energy consumption and degradation multiplying factor of 1.05.

B-1.13 **'Operation and Maintenance Expenses' or 'O&M Expenses**' - In relation to a period, the expenditure incurred in operation and maintenance of the generating station including manpower, spares, consumables (including water), insurance and overheads.

B-1.14 **'Plant Life'** - As per Government of India Gazette Notification No. 265 (E) dated 29th March, 1994, as amended from time to time.

B-1.15 **'Plant Load Factor' or 'PLF'** - In relation to any period, the ratio, expressed as a percentage, of

a) total kWh generated at Generator terminals

to

b) Installed Capacity, expressed in kilowatts (kW) multiplied by number of hours in the relevant period,

B-1.16 **'Rated Capacity'** - In relation to the Generating Station, the Maximum Continuous Rating (MCR) of a Unit multiplied by number of Units in the Generating Station.

B-1.17 **'Settlement Period'** - An hour or any other agreed period during which the Available Capacity shall be taken as constant and equal to the average capacity during the period.

B-1.18 **'Steam Generator Efficiency'** - The ratio, expressed as a percentage, of

a) Gross Calorific Value (GCV) of the fuel fired minus the heat losses in the Steam Generator per unit quantity of fuel, as per international codes, but without heat credit.

to

b) Gross Calorific Value of the fuel fired.

B-1.19 '**Unit'** - Steam Generator - Turbine - Generator and their auxiliaries.

B-2 **Combined Cycle Combustion Turbine (CCCT) Generating Station**

B-2.1 '**Auxiliary Energy Consumption'** – In relation to any period, the ratio, expressed as a percentage, of

(a) gross energy in kWh generated at Generator(s) terminals minus net energy in kWh delivered at the switchyard

to

(b) gross energy in kWh generated at the Generator(s) terminals,

B-2.2 **Calorific Value**:

B-2.2.1 '**Gross Calorific Value' or 'GCV'** – the heat produced in kCal by complete combustion of one kilogram (Kg) of liquid fuel expressed in 'kCal/kg' as per latest version of IS: 1448 (P: 6) or one standard cubic metre of gaseous fuel expressed in 'kCal/Sm^3' as per latest version of ASTM D 3588.

B-2.2.2 '**Net Calorific Value' or 'NCV**' **–** Gross Calorific value minus the heat losses due to moisture in complete combustion of one kilogram of liquid fuel, expressed in 'kCal/kg', as per latest version of IS: 1448 (P : 6) or one standard cubic metre of gaseous fuel expressed in 'kCal/Sm^3' as per latest version of ASTM D 3588.

B-2.3 **Capacity:**

B-2.3.1 '**Maximum Continuous Rating' or 'MCR**' **–** In relation to a Unit or Block, the maximum continuous output at the Generator(s) terminals, guaranteed by the manufacturer with Water/steam injection (if applicable) at ISO-2314 and ISO 3977 reference conditions and corrected to 50 Hz grid frequency and site conditions.

Explanation : Site conditions refer to annual mean dry bulb temperature, annual mean relative humidity, site atmospheric pressure and worst circulating water inlet temperature.

B-2.3.2 '**Rated Capacity' –** In relation to the Generating Station, the Maximum Continuous Rating (MCR) of Block multiplied by the number of Blocks in the Generating Station.

B-2.3.3 '**Demonstrated Capacity' –** In relation to a Unit or Block, the electric output at Generator(s) terminals demonstrated during Performance Acceptance Test as per latest versions of ISO-2314/ASME PTC- 22 for Combustion Turbine and ASME PTC 6 for Steam Turbine after successful trail operation and corrected to 50 Hz grid
frequency and site conditions as at B-2.3.1 above.

B-2.3.4 '**Installed Capacity' –** In relation to the Generating station,

For the first year of plant operation reckoned from COD of the Generating Station :	Rated capacity or sum of the Demonstrated capacities of the Blocks in the Generating Station whichever is less.
For subsequent years of plant operation :	Installed Capacity of Generating station in any year is to be determined by multiplying the first year Installed Capacity by Capacity Degradation Factor for the corresponding year as given in Operation Norms

B-2.3.5 '**Available capacity'** – In relation to any settlement period, the sum of

a) Power delivered or deemed to have been delivered (in case of backing down) at switchyard

and

b) Auxiliary Power Consumption and corrected to average dry bulb temperature of the Settlement Period.

Explanation:

1. Auxiliary Energy Consumption as per operation norms shall be taken as Auxiliary Power Consumption for this purpose.
2. Available capacity, when corrected to site conditions as at B-2.3.1 above, shall not exceed the Installed Capacity.

B-2.4 '**Commercial Operation Date' or 'COD**' – In relation to a Unit or Block, date by which the Maximum Continuous Rating (MCR) or acceptable installed capacity is demonstrated by Performance Acceptance Test as per latest versions of ISO-2314/ASME PTC-22 for Combustion Turbine and ASME PTC-6 for Steam Turbine after successful trial operation including stabilisation. The COD of the Generating Station shall be reckoned from the COD of the last Block.

B-2.5 **Heat Rate**:

B-2.5.1 '**Gross Heat Rate' or 'GHR**' – The heat energy in kCal input to the Unit or Block or Generating station to generate one kWh of electric energy from the Unit or Block or Generating station at Generator's terminals.

B-2.5.2 '**Net Heat Rate' or 'NHR**' - The heat energy in kCal. input to the Unit or Block Generating Station to deliver one kWh of electric energy at the switchyard.

Explanation: The gross Heat Rate and a Net Heat Rate shall be based on NCV of fuel.

B-2.5.2.1 **Net Heat Rate Formulations**

A) The Net Heat Rate for a Settlement Period at any loading of the CCCT Generating Station shall be a) guaranteed Net Heat Rate at site ambient conditions corresponding to loading of the Generating Station multiplied by 1.035 or b) the value determined by the following formula, whichever is less:

$$SNHR = GHR \times \frac{100}{100-AEC}$$

Where, SNHR is the Net Heat Rate of the Generating Station, in kCal/Kwh, during a Settlement Period in combined cycle mode.

GHR is the Gross Heat Rate of the CCCT Generating Station in kCal/kWh corresponding to the loading of the Generating Station during the relevant Settlement Period as per para 1.1.4.2.1 of Operating Norms and corrected to site ambient conditions as per manufacturer's correction factors to take into account the deviations from standard reference conditions of ISO-2314 and ISO-3977.

AEC is the Auxiliary Energy Consumption of the Generating station in combined cycle mode expressed in percentage.

The monthly average Net Heat Rate shall be calculated by weighted average as per the following formula:

$$MNHR = \frac{\text{Sum of (SNHR x NkWh) during the month}}{\text{Sum of NkWh during the month}}$$

Where, MNHR is the monthly average Net Heat Rate in kCal/kWh,
SNHR is the Net Heat Rate for a Settlement Period in kCal/kWh.
NkWh is the net electric energy in kWh delivered at the switchyard during the relevant Settlement Period.

B) For Unit(s) operating in simple cycle mode, the Net Heat Rate for a Settlement Period at any loading shall be a) guaranteed Net Heat Rate at site ambient conditions corresponding to loading of the Unit multiplied by 1.0325 or b) the value determined by the following formula, whichever is less:

$$SNHR\ (SC) = GHR\ (SC) \times \frac{}{100 - AEC\ (SC)}$$

Where, SNHR (SC) is the Net Heat Rate of the Unit in kCal/kWh during a Settlement Period in simple cycle mode.

GHR (SC) is the Gross Heat Rate of the Unit in kCal/kWh corresponding to its average loading during the relevant Settlement Period as per para 1.1.4.2.2 of Operating Norms for simple cycle mode of operation and corrected to site ambient conditions as per manufacturer's correction factors to take into account the deviations from standard reference conditions of ISO-2314.

AEC (SC) is the Auxiliary Energy Consumption of the Unit in simple cycle mode expressed in percentage

Note: 1. Site ambient conditions, for the purpose of determining Gross Heat Rate to account for deviations from ISO conditions, refer to annual mean dry bulb temperature, annual mean relative humidity, site atmospheric pressure and condenser vacuum based on cooling water inlet temperature corresponding to 90% duration.

2. Where a combination of fuels (e.g. Natural Gas and Naphtha) is used, the respective net heat rate for a Settlement Period shall be calculated separately for each fuel.

B-2.6 '**Operation and Maintenance Expenses' or 'O&M Expenses**'
In relation to a period, the expenditure incurred in operation and maintenance of the Generating Station including expenses towards manpower, spares, consumables (including water), insurance and overheads.

B-2.7 '**Plant Life**' **–** As per Govt. of India Gazette Notification No.265 (E) dated 29th March 1994, as amended from time to time.

B-2.8 **Plant Load Factor**:

B-2.8.1 '**Plant Load Factor**' or '**PLF**' **–** In relation to any period, the ratio expressed as a
percentage of

(a) The sum of total kWh delivered at the switchyard and Auxiliary Energy consumption as per operation norms
to
(b) Installed Capacity, expressed in KiloWatts (kW) multiplied by the number of hours in the relevant period.

B-2.8.2 ‘**Deemed Plant Load Factor**’ **–** In relation to any period of operation of the Generating Station, the ratio expressed as percentage of

a) The sum of Available Capacities for each Settlement Period to

b) Installed Capacity multiplied by the number of Settlement Periods

B-2.9 **Plant Configuration**:

B-2.9.1 ‘**Unit**’ **–** In relation to CCCT Generating Station: Combustion Turbine-Generator and auxiliaries.

B-2.9.2 ‘**Block**’ **–** In relation to CCCT Generating Station:

Combustion turbine – Generator(s), associated Waste Heat Recovery boiler(s), connected Steam Turbine – Generator and auxiliaries.

B-2.9.3 ‘**Generating Station**’ **–** In relation to CCCT Generating Station: CCCT Block(s) and balance of plant.

B-2.10 **'Settlement Period**' - An hour or any other mutually agreed period during which the available capacity shall be taken as constant and equal to average capacity during the period.

B-3 **Diesel Generating Station**

B-3.1 **'Auxiliary Energy Consumption**' - In relation to any period, the ratio, expressed as a percentage, of

(a) gross energy in kWh generated at Generator(s) terminals minus net energy in kWh delivered at the switchyard.
to
(b) gross energy in kWh generated at the Generator(s) terminals,

B-3.2 **Calorific Value**:

B-3.2.1 **'Gross Calorific Value**' or '**GCV**' - The heat produced in KCal by complete combustion of one kilogram (Kg) of liquid fuel expressed in 'KCal/Kg' as per latest version of IS: 1448 (P:6).

B-3.2.2 **'Net Calorific Value' or 'NCV'** - Gross Calorific value minus the heat losses due to moisture in complete combustion of one kilogram of liquid fuel, expressed in 'Kcal /kg', as per latest version of IS:1448 (P:6).

B-3.3 **Capacity**:

B-3.3.1 **' Maximum Continuous Rating' or MCR'** - In relation to a Unit the maximum continuous output at the Generator terminals, guaranteed by the manufacturer at ISO-3046 reference conditions and corrected to 50 Hz grid frequency and site conditions.

Explanation : Site conditions refer to annual mean dry bulb temperature, annual mean relative humidity and maximum charge air coolant temperature.

B-3.3.2 **'Rated Capacity'** - In relation to the Generating Station, the Maximum Continuous Rating (MCR) of unit multiplied by the number of units in the Generating Station.

B-3.3.3 **'Demonstrated Capacity**' - In relation to a Unit, the electric output at Generator terminals demonstrated during Performance Acceptance Test as per latest versions of ISO-3046 for Diesel Engine and IS:4722, IS:5422, IS:7132 and IEC-34 for Generator after successful trial operation and corrected to 50 Hz grid frequency and site conditions as at B-3.3.1 above.

B-3.3.4**'Installed Capacity**' - In relation to the Generating station, Rated capacity or sum of the Demonstrated capacities of the units in the generating station whichever is less.

B-3.3.5 **'Available capacity**' - In relation to any settlement period, the sum of

a) power delivered or deemed to have been delivered (in case of backing down) at switchyard
and

b) Auxiliary power consumption

and corrected to annual mean dry bulb temperature at site and 50 Hz grid frequency.

Explanation:

1. Auxiliary Energy consumption shall be taken as Auxiliary Power consumption for this purpose.
2. Available capacity shall not exceed the Installed Capacity.

B-3.4 **'Commercial Operation Date'** or '**COD**' - In relation to a Unit, date by which the Maximum Continuous Rating (MCR) or acceptable installed capacity is demonstrated by a Performance Acceptance Test as per latest versions of ISO-3046 for Diesel Engine and IS:4722, IS : 5422, IS:7132 and IEC-34 for Generator after successful trial operation including stabilisation. The COD of the Generating Station shall be reckoned from the COD of the last Unit.

B-3.5 **'Generating Station**' - In relation to Diesel Engine Generating Station : DG units and balance of plant

B-3.6 **Heat Rate**:

B-3.6.1 **'Gross Heat Rate'** or **GHR**' - The heat energy in kCal input to the Unit to generate one kWh of electric energy at Generator terminals.

B-3.6.2 **'Net Heat Rate' or 'NHR**' - The heat energy in kCal, input to the Generating Station to deliver one kWh at the switchyard.

Explanation: In relation to, Diesel Engine - Generator (DG) Unit, the Gross Heat Rate and the Net Heat Rate shall be based on NCV of fuel.

B-3.6.2.1**Net Heat Rate Formulations**

The daily Net Heat Rate of the Generating Station shall be determined by the following formula:

$$DNHR = GHR \times \frac{100}{100 - AEC}$$

Where, DNHR is the Net Heat Rate of the Generating Station during a day

GHR is the Gross Heat Rate of the Diesel Generating Unit in kCal /kWh corrected to site ambient conditions to take into account the deviations from standard reference conditions of ISO-3046.

AEC is the Auxiliary Energy Consumption, expressed in percentage,

The monthly average Net Heat Rate shall be calculated by weighted average as per the following formula.

$$MNHR = \frac{\text{Sum of (DNHR X NkWh) during the month}}{\text{Sum of NkWh during the month}}$$

Where MNHR is the monthly average Net Heat Rate in kCal/kWh,
DNHR is the Net Heat Rate for a day in kCal/kWh
NkWh is the net kWh delivered at the switchyard during the relevant day

B-3.7 **'Operation and Maintenance Expenses**' or **'O&M Expenses**' -

In relation to a period, the expenditure incurred in operation and maintenance of the generating station including manpower, spares, consumables (including water), insurance and overheads.

B-3.8 **'Plant Life'** - As per Govt. of India Gazette Notification No. 265 (E) dated 29th March, 1994, as amended from time to time.

B-3.9 **Plant Load Factor**:

B-3.9.1 **'Plant Load Factor' or 'PLF'** - In relation to any period, the ratio, expressed as a percentage of

(a) The sum of total kWh delivered at the switchyard and Auxiliary Energy Consumption as per operation norms

to

(b) Installed Capacity, expressed in kilo Watts (kW) multiplied by the number of hours in the relevant period,

B-3.9.2 **'Deemed Plant Load Factor'** - In relation to any period of operation of the Generating Station, the ratio expressed as percentage, of

(a) The sum of available capacities for each Settlement Period
to
(b) Installed capacity multiplied by the number of Settlement Periods

B-3.10 **'Settlement Period'** - An hour or any other mutually agreed period during which the available capacity shall be taken as constant and equal to average capacity during the period.

B-3.11 '**Unit**' - in relation to :

Diesel Engine Generating Station : Diesel Engine Generator and auxiliaries

B-4 **In combustion and Post Combustion Flue Gas Desulphurisation System**

B-4.1 **Specific Reagent Consumption**

Weight of reagent required in Kg per Kg of primary fuel fired in the steam generator.

B-4.2 **Sulphur Dioxide Removal Efficiency**
Ratio of number of moles of SO_2 removed in the desulphurisation system to the number of moles of SO_2 produced in the combustion process, expressed as percentage.

ANNEXURE-C

C-1 SAMPLE CALCULATION FOR DETERMINATION OF FUEL CONSUMPTION FOR A TYPICAL DAY FOR STEAM GENERATOR - TURBINE GENERATING STATION.

(A) DATA

1.	Installed Capacity	2 x 130 MW
2.	Main Steam Parameters	130 kg/cm² (abs), 535°C/535°C
3.	Type of cooling	Closed Cycle with cooling tower
4.	Primary fuel	Domestic coal (run off mine)
(a)	Monthly weighted average Characteristics of coal as Received basis	
(i)	Moisture content	10%
(ii)	Ash Content	35%
(iii)	Hydrogen content	2.86%
(iv)	GCV	4200 kCal/kg
5. (a)	GCV of secondary fuel oil	10,000 kCal/kg
(b)	Density of Secondary fuel oil	0.9 kg/l
6.	Net Generation/day	5 million kWh
	Guaranteed Net Heat Rate of Steam Turbine -Generator	

7(a)	Loading (%)	100	80	60	50
7(b)	Guaranteed Net Heat Rate (kCal/kWh) (as per EPC contract) as per para B-1.12.1 for ash, moisture and hydrogen content of primary fuel	2525	2565	2680	2760

(B) CALCULATIONS

1. Installed capacity : 2 x 130 MW = 260 MW

2. Normative Aux. Energy Consumption at 100% Installed Capacity : 9%

3. Net Installed Capacity : 2x130 ($\underline{100-9}$) = 236.6 MW

4. PLF based on net generation : $\dfrac{5 \times \dfrac{10^6}{100} \times 100}{236.6 \times 10^3 \times 24} = 88.05\%$

5. PLF based on gross generation and auxiliary Energy consumption is to be calculated by iteration upto 3 :

Iteration	0	1	2
PLF	88.05	88.47	88.46
AEC multiplying factor (from table at para 1.1.5.1.3	$1.0+\dfrac{0.08(100-88.05)}{20} = 1.0478$	$1.0+\dfrac{0.08(100-88.47)}{20} = 1.0461$	$1.0+\dfrac{0.08(100-88.46)}{20} = 1.04616$
AEC(%) (from table at para 1.1.5.1	9x1.0478=9.4302	9x1.0461=9.4149	9x1.04616=9.4154
Gross Generation (kWh)	$\dfrac{5\times10^6}{\frac{100-9.4302}{100}} = 5.52\times10^6$	$\dfrac{5\times10^6}{\frac{100-9.4149}{100}} = 5.5197\times10^6$	$\dfrac{5\times10^6}{\frac{100-9.4154}{100}} = 5.5197\times10^6$
Revised PLF (%)	$\dfrac{5.52\times10^6}{260\times24} = 88.47$	$\dfrac{5.5197\times10^6}{260\times24} = 88.46$	$\dfrac{5.5197\times10^6}{260\times24} = 88.46$

6. Gross Heat Rate of Steam Turbine Generator :
   Normative Gross Heat Rate
   from table at Para 1.1.4.1 : $2080+ (2120 - 2080) \times \dfrac{100-88.46}{20}$
   : 2103.08 kCal/kWh

7. GCV as 'fired' basis :
   GCV as 'received' basis : 4200 kCal/kg
   GCV on as fired basis : 4200-100 = 4100 kCal/kg
   (as per para -1.1.4.1.1)
   Moisture content on as received basis : 10%
   Moisture content on as fired basis : 10 + 1 = 11%
   (as per para -1.1.4.1.1)

8. Steam Generator Efficiency :
   Steam Generator Efficiency
   as per formula at para 1.1.4.1.1 : $92.5-\dfrac{(50\times35+630(11+9\times2.86)}{4100}$

   $= 92.5-6.07 = 86.43\%$

9. Net Heat Rate

Normative Gross Heat Rate	:	2103.08 kCal/kWh
Normative Aux. Energy Consumption	:	9.415%
Normative Steam Generator Efficiency	:	86.43%
Normative Daily Net Heat Rate (from formula at Para B- 1.12.1)	:	$\dfrac{2103.08 \times 100}{100 - 9.415} \times \dfrac{100}{86.43} = 2686$ kCal/kWh
Daily Net Heat Rate based on guaranteed value (from item 7 of Data)	:	$2525 + (2565-2525)\dfrac{(100-88.46)}{20}$ = 2548 kCal/kWh
Daily Net Heat Rate based on guaranteed value with degradation factor of 1.05	:	2548 x 1.05 = 2675 kCal/kWh
Applicable Daily Net Heat Rate	:	2675 kCal/kWh

10. Heat Credit of Secondary Fuel Oil :

Fuel Consumption Specific secondary fuel oil consumption (as per para 1.1.6)	:	1.0 ml/gross kWh $\dfrac{1.0}{100-9.415}$ =1.104 ml/net kWh
Allowable fuel oil consumption	:	$\dfrac{5 \times 10^6 \times 1.104}{10^6}$ =5.52 kl/day

GCV of fuel oil = 10,000 kCal/kg

Heat contribution of secondary fuel oil	:	$5.52 \times 10^3 \times 0.9 \times 10{,}000$ kCal/day
	=	49.71×10^6 kCal/day or 0.0497×10^9 kCal/day

11.	Heat input to generating station	:	$5 \times 10^6 \times 2675$ kCal/day
		=	13.375×10^9 kCal/day
12.	Heat input by coal	:	$(13.375 - 0.0497) \times 10^9$ kCal/day
		=	13.3253×10^9 kCal/day

13. Coal consumption

GCV of coal on as fired basis	:	4100 kCal/kg

	Coal Consumption	:	$\dfrac{13.3253 \times 10^9}{4100}$ kg/day
		=	3.250×10^6 kg/day
		=	3250.0 tonnes/day
14.	Total fuel consumption	:	3250.0 t/day of coal + 5.52 kl/day of Secondary Fuel Oil

ANNEXURE - C
(Continued)

C-2 SAMPLE CALCULATIONS FOR DETERMINATION OF FUEL CONSUMPTION FOR A SETTLEMENT PERIOD FOR COMBINED CYCLE COMBUSTION TURBINE (CCCT) GENERATING STATIONS

CASE I : NATURAL GAS AS FUEL (FIRST YEAR OF OPERATION)

A) DATA

1.	First year Installed Capacity	350 MW (2 x 115 MW CT +1 x 120 MW ST)
2.	Combustion Turbine rating at ISO with Natural gas	123 MW
3.	Type of cooling	Closed Cycle with cooling Tower
4.	a) Fuel b) NCV of fuel	Natural Gas 8500 kCal/SM³
5.	NOx control measure	Water injection (NOx emission level 50 ppm)
6.	Settlement Period	1 Hour
7.	Net generation during the Settlement Period	270830 kWh

8.	a) Loading	100%	80%	60%	50%
	b) Guaranteed Net Heat Rate (kCal/kWh) as per EPC contract for Natural Gas with water injection under site ambient conditions	1800	1860	1990	2100

B CALCULATIONS

1.	Installed capacity	350 MW
2.	Normative auxiliary Energy consumption	2.85%

3. Gross Generation during the Settlement Period $= \dfrac{270830}{\dfrac{(100-2.85)}{100}} = \dfrac{27830}{97.15} \times 100 = 278775$ kWh

4. SPLF $\dfrac{278775}{350 \times 10^3} \times 100 = 79.65\%$

5. Net Heat Rate for the Settlement Period (SNHR) :

5.1 Normative Net Heat Rate for the Settlement period

(a) Normative Gross Heat Rate (GHR) under ISO conditions as per para 1.1.3.2.1 corresponding to SPLF of 79.65% with Natural Gas as fuel.

$1730 + \dfrac{(1850 - 1730)}{20} \times (80-79.65)$

= 1732.10 kCal/kWh

b) Adjustment for water injection as per Note 2 under 1.1.3.2.1 = 100 kCal/kWh

c) Normative GHR under site ambient conditions (Refer B-2.5.2.1) (Assuming 1.025 as a factor based on manufacturer's curves for deviations of site ambient conditions (temperature, relative humidity, atmospheric pressure, condenser vacuum) from ISO conditions

= (1732.10 + 100 x 1.025)

= 1877.90 kCal/kWh

d) Normative Net heat rate for the Settlement Period = $1877.90 \dfrac{\times 100}{100-2.85}$

= 1932.99 kCal/kWh

5.2 Net Heat rate for the Settlement Period based on guaranteed value (Item 8 of data)

$=\left\{1860 + \dfrac{(1990 - 1860)}{20} \times (80-79.65)\right\} 1.035$

= 1927.45 kCal/kWh

5.3 Applicable Net heat rate (SNHR) for the settlement period = 1927.45 kCal/kWh

6. Fuel consumption during the Settlement Period :

6.1	Heat input	$= 270830 \times 1927.45$ kCal $= 522.011 \times 10^6$ kCal
6.2	NCV of Natural Gas item 4 (b) of data	= 8500 kCal /Sm^3
6.3	Gas consumption during the Settlement Period	$= \dfrac{522.011 \times 10^6}{8500}$ $= 0.061413 \times 10^6$ Sm^3

CASE II : NATURAL GAS AS FUEL (FOURTH YEAR OF OPERATION)

A) DATA

1.	First year Installed Capacity	= 350MW(2x115MWCT+1x120 MW ST)
2.	Combustion Turbine rating at ISO with Natural Gas	= 123 MW
3.	Type of Cooling	= Closed Cycle with cooling Tower
4.	a) Fuel b) NCV of fuel	= Natural Gas = 8500 kCal/SM³
5.	NOx control measure	= Water injection (Nox emission level 50 ppm)
6.	Settlement Period	= 1 hour
8.	Net generation during the settlement period	= 264570 kWh

8.	a) Loading	100%	80%	60%	50%
	b) Guaranteed Net Heat rate (kCal/kWh) as per EPC contract for Natural Gas with water injection under site ambient conditions	1800	1860	1990	2100

B CALCULATIONS

1.	a)Installed capacity	350 MW
	b) Capacity degradation factor for 4th year	0.9775
	c) 4th year Installed Capacity	350 x 0.9775 = 342.125 MW
2.	Normative auxiliary energy consumption	2.85%

3. Gross Generation during the Settlement Period

$$\frac{264570}{\frac{(100-2.85)}{100}} = \frac{264570}{97.5} \times 100 = 272331 \text{ kWh}$$

4. SPLF = $\frac{272331}{342.125\text{X}10^3}$ X 100 = 79.60%

5. Net Heat Rate for the Settlement Period (SNHR)

5.1 Normative Net Heat Rate for the Settlement period

(a) Normative Gross Heat Rate (GHR) under ISO conditions as per para 1.1.4.2.1 corresponding to SPLF of 79.60% with Natural Gas as fuel

$= 1730 + \frac{(1850 - 1730)}{20} \times (80\text{-}79.6)$

= 1732.40 kCal./kWh

b) Adjustment for water injection as per Note 2 under 1.1.4.2.1 = 100 kCal/kWh

c) Normative GHR under site ambient conditions (Refer B-2.5.2.1) (assuming 1.025 as a factor based on manufacturer's curves for deviations of site ambient conditions (temperature, relative humidity, atmospheric pressure, condenser vacuum) from ISO conditions

= (1732.40+100)x1.025

= 1878.21 kCal/kWh

c) Normative Net heat rate for the Settlement Period = $1878.21 \; \frac{\text{x} \; 100}{100-2.85}$

= 1933.31 kCal/kWh

5.2 Net Heat rate for the Settlement Period based on guaranteed value (Item 8 of data)

$= \{1860 + \frac{1990 - 1860}{20} \text{ x } (80\text{-}79.60)\}1.035$

= 1927.79 kCal/kWh

5.3 Applicable Net Heat Rate (SNHR) for the settlement period = 1927.79 kCal/kWh

6. Fuel consumption during the Settlement Period :

6.1	Heat input	$= 264570 \times 1927.79$ kCal
		$= 510.035 \times 10^6$ kCal
6.2	NCV of Natural Gas item 4 (b) of data =	8500 kCal /Sm^3
6.3	Gas consumption during the Settlement Period =	$\dfrac{510.035 \times 10^6}{8500}$
		$= 0.060004 \times 10^6$ Sm^3

CASE III : NAPHTA AS FUEL (FIRST YEAR OF OPERATION)

A) DATA

1. First year Installed Capacity = 680MW(2x225MW CT+1x230 ST)

2. Combustion Turbine rating at ISO with Natural Gas = 240 MW

3. Type of Cooling = Once through system

4. a) Fuel = Naphtha
   b) NCV of fuel = 10500 kCal/kg

5. NOx control measure = Water injection (NOx emission level 75 ppm)

6. Settlement Period = 1 hour

7. Net generation during the Settlement Period = 562370 kWh

8.

		100%	80%	60%	50%
a)	Loading	100%	80%	60%	50%
b)	Guaranteed Net Heat rate (kCal/kWh) as per EPC contract for Naphtha with water injection under site ambient conditions	1700	1750	1850	1950

B CALCULATIONS

1. a)Installed capacity = 680 MW

2. Normative auxiliary energy Consumption = 2.75%

3. Gross Generation during the Settlement Period =578272 kWh

$$= \frac{562370}{\frac{(100-2.75)}{100}} = \frac{(562370)}{97.25} \times 100$$

4. SPLF

$$= \frac{578272}{680X10^3} X\ 100 = 85.04\%$$

5. Net Heat Rate for the Settlement Period (SNHR)

5.1 Normative Net Heat Rate for the Settlement Period

(a) Normative Gross Heat Rate (GHR) under ISO conditions as per para 1.1.4.2.1 corresponding to SPLF of 85.04% with Natural Gas as fuel.

$$= 1580 + \frac{(16300 - 1580)}{20} \text{ X } 100\text{-}85.04$$

= 1617.40 kCal/kWh

(b) Normative Gross Heat Rate (GHR) under ISO conditions with Naphtha as fuel

= 1617.40 x 1.02

= 1649.75 kCal/kWh

(c) Adjustment for water injection as per Note 2 under para 1.1.4.2.1

= 50 kCal/kWh for emission level 100 ppm

$$= \frac{50\text{x}100}{75} \text{ kCal/kWh for emission level of of 75 ppm}$$

= 66.67 kCal/KWh

d) Normative GHR under site ambient Conditions (Refer 1.1.4.2.1) (Assuming 1.025 as a factor based on manufacturer's curves for deviations of site ambient conditions (temperature relative humidity, atmospheric pressure, condenser vaccum) from ISO conditions

= (1649.75 + 66.67) x 1.025

= 1759.33 kCal/kWh

e) Normative Net Heat Rate for the Settlement Period

$$= \frac{1759.33\text{x}100}{100\text{-}2.75}$$

= 1809.08 kCal/kWh

5.2 Net Heat Rate for the Settlement Period based on guaranteed value (Item 8 of data)

$$=\{1700 + \frac{(1750\text{-}1700)}{20} \text{ x } (100\text{-} 85.04)\}1.035$$

= 1798.21kCal/kWh

5.3 Applicable Net Heat Rate (SNHR) for the Settlement Period = 1798.21 kCal/kWh

6. Fuel Consumption during the Settlement Period :

6.1	Heat input	=	562370x1798.21 kCal
		=	1011.259×10^{6} kCal
6.2	NCV of Naphtha (Item 4(b) of data)	=	10500 kCal/Sm^3
6.3	Naphtha consumption during the settlement period	=	$\frac{1011.259 \times 10^{6}}{10500}$
		=	0.096310×10^{6} Kg
		=	96.310 tonnes

CASE IV: DUAL FUEL (NATURAL GAS AND NAPHTHA) - 1ST YEAR OF OPERATION

A) DATA

1.a)	First Year Installed Capacity on Natural Gas	=	105 MW (2x35 MW CT + 1x35 MW ST)
b)	First Year Installed capacity on Naphtha	=	102 MW
2	Combustion Turbine rating At ISO with Natural Gas	=	39 MW
3.	Type of cooling	=	Closed Cycle with cooling Tower
4.	a) Fuel	=	Natural Gas + Naphtha
	b) NCV of fuel	=	8500 kCal/Sm^3 for Natural Gas and 10,500 Kcal/kg for Naphtha
5.	a) Natural Gas consumption as measured during the settlement period	=	12000 Sm^3
	b) Naphtha consumption as measured during the settlement period	=	6.48 tonnes
	c) Ratio of Heat input with Natural Gas & Naphtha during the settlement period	=	(12000x8500) : (6.48x10^{3}x10500)
		=	60:40
6.	NOx control measure	=	Water injection (NOx emission level 50 ppm with Natural Gas & 75 ppm with Naphtha)
7.	Settlement Period	=	1 hour
8	Net generation during the Settlement Period	=	83330 kWh

9.	a)	Loading	100%	80%	60%	50%
	b)	Guaranteed Net Heat Rate (kCal/kWh) as per EPC contract for Natural Gas with water injection under site ambient conditions	1940	2000	2120	2230
	c)	- do – for Naphtha	1960	2020	2140	2250

B) CALCULATIONS

1.(a) First Year Installed capacity on Natural Gas = 105 MW

(b) First Year Installed capacity on Naphtha = 102 MW

(c) Installed Capacity with dual fuel operation for the Settlement Period = 105 x 0.6 + 102 x 0.4 = 103.8 MW

2. Normative Auxiliary Energy Consumption (AEC)

a) Natural Gas = 2.85%

b) Naphtha = 3.00%

c) Duel Fuel Operation = 2.85 x 0.6 + 3.00 x 0.4 = 2.91%

3. Settlement Period Plant Load Factor (SPLF)

Gross Generation during the settlement period $= \dfrac{83330 \text{ kWh}}{\left(\dfrac{100-2.91}{100}\right)}$ = 85828 kWh

$$\text{SPLF} = \frac{85828}{103.8 \times 10^3} \times 100$$

= 82.69%

4. Net Heat Rate for the settlement period with Natural gas:

4.1 Normative Net Heat Rate for the settlement period

a) Normative Gross Heat Rate (GHR) under ISO conditions as per para 1.1.4.2.1 corresponding to SPLF $= 1800 + \dfrac{(1850 - 1800)}{20} \times (100-82.69)$

82.69% with Natural Gas a fuel = 1843.28 kCal/kWh

b) Adjustment in Gross Heat Rate for water injection for NOx control as per Note 2 under para 1.1.4.2.1 = 100 kCal/kWh

c) Normative GHR under site ambient conditions (Refer B-2.5.2.1) (Assuming 1.025 as a factor based on manufacturer's curves for deviations of site ambient conditions (temperature, relative humidity, atmospheric pressure, condenser vacuum) from ISO conditions)

= (1843.28 + 100) x 1.025

= 1991.86 kCal/kWh

d) Normative Net heat rate for the settlement period = $\frac{1991.86 \times 100}{(100-2.85)}$

= 2050.29 kCal/kWh

4.2 Net Heat Rate for the Settlement Period based on guaranteed value (item 9 of data) $\{1940 + \frac{(2000 - 1940)}{20} \times (100-81.69)\} 1.035$

= 2061.65 kCal/kWh

4.3 Applicable Net heat rate (SNHR) for the settlement period = 2050.29 kCal/kWh

5. Net Heat Rate for the Settlement Period with Naphtha

5.1 Normative Net Heat Rate for the Settlement Period

a) Normative Gross Heat Rate (GHR) under ISO conditions as per para 1.1.4.2.1 corresponding to SPLF 82.69% with Natural Gas

= $1800 + \frac{(1850-1800)}{20} \times (100-82.69)$

= 1843.28 kCal/kWh

b) Normative GHR under ISO conditions with Naphtha as fuel (as per para 1.1.4.2.1 Note 1) = 1843.28 x 1.02

= 1880.15 kCal/kWh

c) Adjustment in Gross Heat Rate for water injection for NOx control as per Note 2 under para 1.1.4.2.1) = 50 kCal/kWh for NOx emission of 100 ppm

		=	$\frac{50 \times 100}{75}$ k Cal /kWh for NOx emission of 75 ppm
		=	66.67 kCal/kWh
d)	Normative GHR under site ambient conditions (Refer B -2.5.2.1) (Assuming 1.025 as a factor based on manufacturer's curves for deviations of site ambient conditions (temperature, relative humidity, atmospheric pressure, condenser vacuum) from ISO conditions)	=	(1880.15 + 66.67) x 1.025 1995.49 kCal/kWh
e)	Normative Net Heat Rate for the Settlement Period	=	$1995.49 \times \frac{100}{100 - 3.00}$
		=	2057.21 kCal/kWh
5.2	Net Heat Rate for the Settlement Period based on guaranteed value (Item 9 of data)	=	$[1960 + \frac{(2020-1960)}{20} \times (100-82.69)]1.035$
		=	2082.35 kCal/kWh
5.3	Applicable Net Heat Rate (SNHR) for the settlement period	=	2057.21 kCal/kWh

6. Fuel Consumption during the Settlement period :

6.1	a)	Total Net Generation	=	83330 kWh
	b)	Net Generation with Natural Gas	=	83330x 0.6
			=	49998 kWh
	c)	Net Generation with Naphtha	=	83330x0.4
			=	33332 kWh
6.2	a)	Heat input through Natural Gas	=	49998x2050.29 kCal
			=	102.510×10^6 kCal
	b)	NCV of Natural Gas (item 4 (b) of data)	=	8500 kCal/Sm^3
	c)	Gas consumption during the settlement period	=	$\frac{102.510 \times 10^6}{8500}$
			=	0.012060×10^6 Sm^3
6.3	a)	Heat input through Naphtha	=	33332x2057.21 kCal

			=	68.571×10^{6} kCal
	b)	NCV of Naphtha (Item 4(b) of data)	=	10500 kCal/kg
	c)	Naphtha consumption during the Settlement Period	=	$\frac{68.571 \times 10^{6}}{10500}$
			=	0.006531×10^{6} Kg
			=	6.531 Tonnes
6.4	Total Fuel Consumption during the Settlement Period		=	0.012060×10^{6} Sm^{3} of Natural Gas + 6.531 Tonnes of Naphtha

CASE V: DUAL FUEL (NATURAL GAS AND NAPHTHA)- 4TH YEAR OF OPERATION)

A) DATA

1.a)	First Year Installed Capacity ST)	=	105 MW (2 x 35 MW CT +1x35 MW
b)	First Year Installed Capacity on Naphtha	=	102 MW
2.	Combustion Turbine rating at ISO with Natural Gas	=	39 MW
3.	Type of Cooling	=	Closed Cycle with cooling Tower
4. a)	Fuel	=	Natural Gas + Naphtha
b)	NCV of fuel	=	8500 kCal/Sm^3 for Natural Gas and 10,500 Kcal/Kg for Naphtha
5. a)	Natural Gas consumption as measured during the settlement period	=	12000 Sm^3
b)	Naphtha consumption as measured during the settlement period	=	6.48 tonnes
c)	Ratio of Heat input with Natural Gas & Naphtha during the settlement period	= =	(12000x8500) : (6.48x10^{3}x10500) 60:40
6.	Ratio of Cummulative generation in the preceding 3 years with Natural Gas and Naphtha	=	55 : 45
7.	Settlement Period	=	1 hour

8.	NOx control measure	=	Water injection (NOx emission level 50 ppm with Natural Gas & 75 ppm with Naphtha)		
9.	Net generation during the settlement period	=	83330 kWh		
10. a)	Loading	100%	80%	60%	50%
b)	Guaranteed Net Heat Rate (kCal/kWh) as per EPC contract for Natural Gas with water injection under site ambient conditions	1940	2000	2120	2230
c)	- do - for Naphtha	1960	2020	2140	2250

B) CALCULATIONS

1.(a) First Year Installed capacity = 105 MW

(b) Capacity degradation factor for 4^{th} year of operation = 0.9775 x 0.55 + 0.970 x 0.45
(Weighted average of degradation factors with Naphtha & Gas) = 0.9741

(c) 4^{th} year Installed Capacity on Natural Gas = 105 x 0.9741 = 102.2805 MW

(d) -----on---- Naphtha = 102 x 0.9741
= 99.3582 MW

(e) 4^{th} Year Installed Capacity with dual operation for the Settlement Period = 102.2805 x 0.6 + 99.3582 x 0.4
= 101.11158 MW

2.0 Normative Auxiliary Energy Consumption (AEC)

a) Natural Gas = 2.85 %
b) Naphtha = 3.00 %

c) Dual Fuel Operation = 2.85 x 0.6 + 3.00 x 0.4
= 2.91 %

3.0 Settlement Period Plant Load Factor (SPLF)

Gross Generation during the Settlement Period =

$$\frac{83330}{\left(\frac{100-2.91}{100}\right)} \text{ kWh}$$

= 85828 kWh

$$\text{SPLF} = \frac{85828}{101.11158 \times 10^3} \times 100$$

= 84.88 %

4.0 Net Heat Rate for the Settlement Period with Natural Gas :

4.1. Normative Net Heat Rate for the Settlement Period

a) Normative Gross Heat Rate (GHR) under ISO conditions as per para 1.1.4.2.1) corresponding to daily plf of 84.88% with Natural Gas as fuel

$$= 1800 + \frac{(1850-1800)}{20} \times (100-84.88)$$

= 1837.80 kCal/kWh

b) Adjustment in Gross Heat Rate for water injection for NOx control as per Note 2 under para 1.1.4.2.1 = 100 kCal/kWh

c) Normative GHR under site ambient Conditions (Refer B-2.5.2.1) (Assuming 1.025 as a factor based on manufacturer's curves for deviations of site ambient conditions (temperature, relative humidity, atmospheric pressure, condenser vacuum) from ISO conditions)

= (1837.80 + 100) x 1.025

= 1986.25 kCal/kWh

d) Normative Net heat rate = 1986.25 x 100 for the settlement period ------------ (100-2.85)

= 2044.52 kCal/kWh

4.2 Net Heat Rate for the Settlement Period based on guaranteed value (Item 10 of data) = $\{(1940 + \frac{(2000-1940)}{20} \times (100-84.88)\}\ 1.035$

= 2054.85 kCal/kWh

4.3 Applicable Net Heat Rate (SNHR) for the Settlement Period = 2044.52 kCal/kWh

5. Net Heat Rate for the Settlement Period with Naphtha :

5.1 Normative Daily Net Heat Rate

a) Normative Gross Heat Rate (GHR) under ISO conditions as per para 1.1.4.2.1) corresponding to SPLF of 84.88% with Natural Gas

= $1800 + \frac{(1850-1800)}{20} \times (100-84.88)$

= 1837.80 Kcal/kWh

b) Normative GHR under ISO conditions with Naphtha as fuel (as per para 1.1.4.2.1 Note 1)

= 1837.80 x 1.02

= 1874.56 kCal/kWh

c) Adjustment in Gross Heat Rate for water injection for NOx control as per Note 2 under para 1.1.4.2.1)

= 50 kCal/kWh for NOx emission of 100 ppm

= $\frac{50 \times 100}{75}$ kCal/kWh for NOx emission of 75 ppm

= 66.67 kCal/kWh

d) Normative GHR under site ambient conditions (Refer B-2.5.2.1) (Assuming 1.025 as a factor based on manufacturer's curves for deviations of site ambient conditions (temperature, relative humidity, atmospheric pressure, condenser vacuum) from ISO conditions)

= (1874.56 + 66.67)x1.025

= 1989.76 kCal/kWh

e)	Normative Net heat rate for the Settlement Period	=	$\frac{1989.76 \times 100}{(100 - 3.00)}$
		=	2051.30 kCal/kWh

5.2	Net Heat Rate for the Settlement Period based on guaranteed value (item 10 of data)	=	$[1960 + \frac{(2020-1960)}{20} \times (100-84.88)]\ 1.035$
		=	2075.55 kCal/kWh
5.3	Applicable Net Heat Rate (SNHR) for the Settlement Period	=	2051.30 kCal/kWh

6. Fuel Consumption during the Settlement Period :

6.1	a)	Total Net Generation	=	83330 kWh
	b)	Net Generation on Natural Gas	=	83330 x 0.6
			=	49998 kWh
	c)	Net Generation on Naphtha	=	83330 x 0.4
			=	33332 kWh
6.2	a)	Heat input though natural gas	=	49998 x 2044.52 kCal
			=	102.222×10^6 kCal
	b)	NCV of Natural Gas (Item 4(b) of data)	=	8500 kCal/Sm^3
	c)	Gas consumption during the settlement period	=	$\frac{102.222\text{x}10^6}{8500}$
			=	0.012026×10^6 Sm^3
6.3	a)	Heat input through Naptha	=	33332 x 2051.30 kCal
			=	68.374×10^6 kCal
	b)	NCV of Naphtha (Item 4(b) of data)	=	10500 kCal/kg
	c)	Naphtha consumption during the settlement period	=	$\frac{68.374\text{x}10^6}{10500}$

		=	0.006512×10^6 Kg
		=	6.512 tonnes
6.4	Total Fuel Consumption during the settlement period	=	0.012026×10^6 Sm^3 of Natural Gas + 6.512 tonnes of Naphtha

Annexure-D

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