**CENTRAL ELECTRICITY REGULATORY COMMISSION**
**NEW DELHI**

**Coram:**

1. **Shri Ashok Basu, Chairman**
2. **Shri K.N. Sinha, Member**

**Petition No.: 67/2003**

**(suo-motu)**

**In the matter of**

Determination of terms and conditions of tariff

**ORDER**
**(DATE OF HEARING : 10, 11 & 12.11.2003)**

**CHAPTER 1**

**Background**

1.1 Central Electricity Regulatory Commission (hereinafter referred to as "the Commission") was constituted in July 1998 under the Electricity Regulatory Commissions Act, 1998. With the omission of Section 43A(2) of the Electricity (Supply) Act, 1948, which enabled the Central Government to determine the terms and conditions of tariff, the jurisdiction to regulate tariff came to be vested in the Commission. Consequently, the Commission initiated steps to determine the terms and conditions of tariff. However, as an interim measure the Commission decided to continue with the terms and conditions laid down by the Central Government and the project–specific tariff notifications issued by that Government by virtue of powers under Section 43A(2) of the Electricity (Supply) Act, 1948, until the terms and conditions of tariff were notified by the Commission.

1.2 During 1999, the Commission circulated a staff consultative paper to highlight certain issues in bulk power tariff regulation, and certain other consultation papers, which were treated as suo motu petitions for determination of terms and conditions of tariff. Through an elaborate consultative process, the terms and conditions of tariff were notified by the Commission in March 2001, valid for a period of three years from 1.4.2001. The fresh terms and conditions of tariff, to be effective from 1.4.2004 are required to be notified by the Commission

1.3 Meanwhile, the Electricity Act, 2003, (hereinafter referred to as "the Act") came into effect. Under Section 61 of the Act the Commission is to specify the terms and conditions for the determination of tariff. Section 62 of the Act envisages that based on the terms and conditions specified by the Commission, the Commission shall determine the actual tariff. An important feature of Section 61 is that the State Electricity Regulatory Commissions are to be guided by the principles and methodologies specified by the Central Commission for determination of tariff applicable to the generating companies and transmission licensees. According to provisions of the Act, the Central Commission has jurisdiction to specify the terms and conditions for the determination of tariff (including the principles and methodologies) as well as determine the tariff, which, inter alia, extends to:

(a) Regulate the tariff of generating companies owned or controlled by the central Government;

(b) Regulate the tariff of generating companies other than those owned or controlled by the Central Government specified in Clause (a) above, if such generating companies enter into or otherwise have a composite scheme for generation and sale of electricity in more than one State;

(c) Regulate the inter-state transmission of electricity;

(d) Determine tariff for inter-state transmission of electricity;

1.4 Under section 178 (3) of the Act, the terms and conditions of tariff are to be specified by the Commission through the Regulations after previous publication. As a first step, the Commission, in January 2003, solicited comments on the terms and conditions of tariff regulations dated 26.03.2001 valid for the period 01.04.2001 - 31.03.2004. This was followed by a staff discussion paper (hereinafter referred to as the Discussion Paper), published in June 2003, on terms and conditions of tariff, to elicit views from the stakeholders and other persons interested in the subject matter as a part of the consultative process. The organisations and individuals listed in the schedule attached to this order responded to the issues. As a further step in the direction of the consultative process, the Commission held an open hearing from 10th to 12th November 2003, when the stakeholders and others concerned were given opportunity to make oral presentations. A further opportunity for filing their specific views on the thrust of the arguments made at the presentations during the open hearing was also given to the stakeholders. This opportunity was availed of by a large number of stakeholders.

1.5 The Commission, in the process of specifying the terms and conditions for determination of tariff, is to perform a delicate task of balancing the interests of all the stakeholders. In order to meet massive investment requirement and growth targets of electricity sector, the Commission has to facilitate fresh investments, both through the public sector as well as the private sector for growth of the electricity industry and bring about over all efficiency in the sector. At the same time it has to be ensured that the price of electricity, which is an essential commodity, is reasonable to the end consumers. While deciding on the terms and conditions of tariff, the Commission has been guided by this twin objective.

1.6 The Act lays the foundations for new unbundled power sector functioning in a competitive environment providing for new opportunities for investment in generation, transmission, distribution and trading as well as providing new choices to consumers. It is the responsibility of the Commission, the lead regulator in the electricity sector, to translate the objective of the Act into action to accomplish the intent and to create a new and vibrant electricity supply industry. In this direction, the Commission strongly feels the need for moving away from the prevailing cost-plus regime for the determination of tariff to a competitive market. The ideal way to achieve this objective would be to adopt the competitive bidding route for all new investment in generation, transmission and distribution. However, the leading role in this direction is to be performed by the Central Government by laying down the guidelines for competitive bidding as envisaged under Section 63 of the Act. The Commission, therefore, urges the Central Government to notify the guidelines for the purpose of adopting transparent bidding procedure for all future projects. A transparent competitive bidding process for projects provides an in-built incentive for maximizing efficiency at a competitive cost under perfect or near perfect market conditions. It should result in cheaper tariff. The Commission is of the considered opinion that the future investment even in the central power sector projects also needs to be through the competitive bidding process and the central power sector utilities should obtain projects through this route rather than developing projects on cost-plus basis.

1.7 Under the prevailing circumstances and in the absence of competitive bidding rules, which are to be notified by the Government, the Commission has no option but to perform the function of regulation of tariff in the cost-plus regime. Nevertheless, the Commission has decided to move away from intrusive regulation based on actual parameters to light handed regulation based on normative parameters as far as possible since the Commission firmly believes in minimum regulation. In line with this objective and within the constraints of regulating tariff in a cost-plus regime, the Commission intends to move towards laying down the normative parameters, as against actuals, for regulation and determination of tariff, since normative parameters would provide strong motivation for achieving efficiency and economy in the electricity sector. Accordingly, the Commission, by adopting this approach, has tended towards normative parameters practically in all aspects, except the capital cost of the project – a subject matter which has been discussed subsequently. However, for this purpose, a whole range of factors including financial, technical and site related issues have to be taken into account, which requires deeper study, analysis and close interaction with the stakeholders and investors. This is an involved and time consuming exercise. Though the Commission would have liked to specify even the project cost on a normative basis, it has deferred it in view of the limitation in time available for prescribing fresh terms & conditions to be effective from 1.4.2004. However , the Commission may, at a later stage, move in this direction.

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# CHAPTER 2

## Operational Norms

### THERMAL POWER GENERATING STATIONS

### Existing Provisions

2.1 The operational norms in respect of gross station heat rate, auxiliary energy consumption and specific fuel oil consumption of thermal power generating stations of the regulated central power generating companies namely NTPC, NLC and NEEPCO are governed, for the present, by the Commission's tariff notification dated 26.3.2001 applicable for the tariff period 1.4.2001 to 31.3.2004 in the following manner:

(a) Operational norms as per project-specific tariff notification issued by the Central Government in respect of the existing generating stations of NTPC, such as Singruali STPS, Ramagundam STPS, etc.

(b) Operational norms as per the Power Purchase Agreements (PPAs)/Bulk Power Supply Agreements (BPSAs) for the existing and new generating stations of NTPC and NLC for which no tariff notification had been issued by the Central Government, such as Kayamkulam GPS, FGUTPP Unchahar, Stage-II, Vindhyachal STPS Stage-II, NLC TPS-II (Stage-I & II), etc.

(c) Operational norms for small gas turbine power generating stations of 50 MW and below such as Assam GPS and Agartala GPS of NEEPCO, and

(d) Operational norms for other generating stations not covered under any of the above three categories.

2.2 The existing tariff notification dated 26.3.2001 of the Commission provides as follows in explanation to clause 2.4 and made applicable to the new generating stations of NTPC namely Faridabad, Vindhyachal, etc.:

*"For the purpose of calculating the tariff, the operating parameters, i.e. "Station Heat Rate", "Secondary Fuel Oil Consumption" and "Auxiliary Energy Consumption" shall be determined on the basis of actual or norms, whichever is lower"*

2.3 This particular provision was continued in order to maintain *status quo* on operational norms as per Ministry of Power notification dated 30th March 1992 for the new thermal power generating stations.

**Views of the Stakeholders**

2.4 As has been stated earlier, the Commission solicited comments first on the tariff notification dated 26.3.2001 and thereafter, on the Discussion Paper published in June,2003 followed by open hearing on 10-12 November, 2003. These revealed divergence of views amongst various stakeholders as has been discussed , briefly, in paras to follow:

(a) The State Electricity Boards and State Transmission Utilities have sought the operational norms based on actual performance of best operating generating stations and have sought trimming down of the operational norms for both, the existing as well as new generating stations. They have further sought adjustment based on actual parameters achieved or the norms, whichever is lower.

(b) On the other hand the central generating companies and state generating companies have sought continuation of the existing norms for the existing generating stations, without adjusting the tariff in relation to actual parameters achieved. According to them, actual has no relevance in the performance-based regulation, based on norms. IPPs have sought that norms negotiated in PPA should not be changed over the entire life of the generating station. CII has stated that the existing norms are already very stringent and should be continued.

**Actual operational parameters of thermal power generating stations**

2.5 The central power generating companies were directed to furnish quarterly operational data for their coal-based and natural gas/liquid fuel - based generating stations like generation at generator terminal and generation at bus-bars, average PLF, weighted average station heat rate, auxiliary energy consumption, consumption of coal/natural gas/liquid fuel, specific fuel oil consumption, secondary fuel oil consumption and corresponding weighted average GCV of each of the fuels. NTPC furnished the operational data for the period January 2001 to December 2002 and January 2003 to March 2003. NLC and NEEPCO also submitted their actual performance data for the period January 2001 to March 2003. The actual operational data of some of the good operating generating stations of the state utilities and IPPs have also been gathered from the published data, available on their web sites and from the submissions made before the Commission at the open hearing.

2.6 NTPC had not indicated any single number for the weighted average station heat rate in the quarterly operational data for the coal-based generating stations but had given a range. Further, the coal consumption was not furnished. Instead coal receipt for the quarter was furnished. Therefore, the gross station heat rate has been reworked at the Commission based on the coal receipt, secondary fuel oil consumption, weighted average GCV of coal and secondary fuel oil, and generation at the generator terminal as furnished by NTPC for the period April 2001 to March 2003. It is possible that there are differences between the average annual coal receipt and consumption, but the impact on annual average figure of station heat rate is considered to be negligible. These were presented to the stakeholders during the open hearing. Subsequent to hearings, NTPC has pointed out that the computed figures for some of the generating stations are at variance with their computations. The variation in figures was found to be on account of taking generation based on PLF. It appears from NTPC's letter dated 20.11.2003 that PLF figures were including some deemed generation whereas the generation given by them was not including any deemed generation. The variation in Kawas CCGT was on account of non-conversion of liquid fuel consumption in Kilolitres which was incidentally indicated by NTPC in kg. As such, the computations have been re-worked out based on actual generation figures but still there may be minor variations, probably on account of considering GCV of secondary fuel oil as 10,000 kcal/lit as the actual average GCV of oil was not indicated by NTPC. NTPC has now furnished the actual station heat rates of generating stations based on coal consumption also. However, the inference drawn by us still holds good and has been vindicated by NTPC's own computations.

2.7 The operational norms of station heat rate, auxiliary energy, and specific fuel oil consumption are discussed below in the light of actual operational performance of central power sector utilities and suggestions and comments of the stakeholders.

**Station Heat Rate**

**Existing Coal-based generating stations**

2.8 The normative heat rates and actual heat rates for NTPC, State Utilities and IPPs generating stations for the period April 2001 to March 2003 as per data received from them, are summarised below:

**Table-2.1**

| Name of Plant/ Capacity | PLF (%) | SHR Norm (In kCal/kWh) | Actual Average SHR (In kCal/kWh) |
|---|---|---|---|
| **200/210 MW set Stations** | | | |
| Dadri NCTPS/ 840 MW | 88 | 2500 | 2477 |
| Unchahar STPS/ 840 MW | 86 | 2500 | 2496 |
| Kahalgaon STPS/ 840 MW | 69 | 2550 | 2491 |
| Vijaywada TPS/ 1260 MW | 93 | 2500 | 2466 |
| Rayalseema TPS/420 MW | 94 | 2500 | 2336 |
| Dahanu TPS/ 500 MW | 97 | 2500 | 2255 |
| Gandhi Nagar / 1050 MW | 73 | 2500 | 2509 |
| Wanakbori TPS/ 1470 MW | 84 | 2500 | 2462 |
| **500 MW set Stations** | | | |
| Rihand STPS/ 1000 MW | 89 | 2460 | 2388 |
| Talcher STPS/ 1000 MW | 70 | 2500 | 2408 |
| Trombay TPS/ 1000 MW | 74 | 2500 | 2400 |
| Kothagudam TPS -V/ 500 MW | 91 | 2500 | 2311 |
| **Stations having combination of 200/210 MW and 500 MW set** | | | |
| Singrauli STPS/ 2000 MW | 91 | 2500 | 2413 |
| Korba STPS/ 2100 MW | 90 | 2500 | 2414 |
| Vindhyachal STPS/ 2260 MW | 83 | 2500 | 2458 |
| Ramagundam STPS/ 2100 MW | 90 | 2500 | 2457 |
| Farakka STPS/ 1600 MW | 63 | 2500 | 2476 |
| Anpara TPS/ 1630 MW | 83 | 2500 | 2413 |

2.9 It can be seen that the actual operation parameters of station heat rate based on coal consumption are lower than the respective station heat rate norms for NTPC generating stations but are comparable to the good operating stations of State utilities and IPPs in the respective categories.

2.10 The marginally high heat rate in case of eastern region generating stations of NTPC as compared to other regions could be attributed to low Plant Load Factor (PLF) due to lower dispatch in the eastern region. However, after ABT, bottled up power in the eastern region is being traded with other regions and the dispatches are expected to be more in future.

2.11 For coal-based Kahalgaon STPS, the heat rate norm of 2550 kCal/kWh was given by CEA vide letter No. MT/29/95-TTD/CEA/059 dated 29.12.1995, which formed the basis for energy charge in the project-specific tariff notification and was adopted by the Commission for the tariff period 2001-04. This was the relaxed norm as compared to the prevailing norms for other coal-based generating stations of NTPC and norms as per Central Government tariff notification dated 30.3.1992. It can be seen that average actual performance parameters for Kahalgaon STPS are comparable with other generating stations of NTPC and *prima facie* there is no case for continuation of the relaxed heat rate norms for Kahalgaon STPS. We have, therefore, come to the conclusion that there is no need for continuation of relaxed station heat rate norm for Kahalgaon STPS.

2.12 It can be seen that the station heat rate in different categories of coal-based generating stations are varying in the following ranges:

**Table-2.2**

| Particulars | 200 /210 MW/ 250 MW Series | 500 MW sets Series | Combination of 200/210/250MW & 500 MW Series |
|---|---|---|---|
| PLF | 69 – 97 | 70 - 91 | 83 - 91 |
| Station Heat Rate | 2255 –2509 | 2311 – 2428 | 2413 - 2476 |
| Average of NTPC generating stations | 2477.49 | 2431.56 | 2443.60 |

2.13 A point has been made by NTPC that under ABT regime, partial loading on account of lower scheduling has been observed in Dadri (Coal), Kahalgaon, Farrakka, Kawas, Anta, Auraiya & Dadri (Gas) and may get extended to other generating stations also. NTPC has further contended that the computed heat rate values have to be corrected for measurement error by 21 kCal/kWh as per IS 1350 para-II. However, in our opinion such an error of measurement gets neutralised as measurements are large in numbers.

2.14 We have carefully considered the issue of station heat rate norms and are of the view that there is scope for reducing norm without affecting operational flexibility in 500 MW sets series. We also feel that the station heat rate norms for 200/210/250 MW sets could be retained at the current level. Accordingly, the following station heat rate norms shall be adopted for the existing NTPC generating stations:

**Table-2.3**

| NTPC | 200 /210 MW/ 250 MW Series | 500 MW Series |
|---|---|---|
| SHR Norm (kCal/kWh) | 2500 | 2450 |

**Note:**

(i) The station heat rate norm for 500 MW series shall be reduced by 40 kCal/kWh for electric driven Boiler Feed Pump.

(ii) Generating stations having a combination of 200/210/250 MW series and for 500 MW series, the station heat rate norm shall be weighted average station heat rate of above two series.

**New Coal based Generating Stations**

2.15 APTRANSCO and APERC have stated in their submissions that the following station heat rate norms have been agreed to by the developers in the PPAs for new IPP projects in the State and approved by APERC, and the same are better than Central Government norms of 1992:

**Table-2.4**

| Name of Plants | Capacity | SHR (kCal/kWh) |
|---|---|---|
| Ramagundam STPS by BPL | 2 x 260 MW | 2400 |
| Rayalseema TPP – II by APGENCO | 2 x 210 MW | 2350 |

2.16 We are given to understand that these generating stations are being developed as base load generating stations with fairly high operating level. However, these generating stations are yet to be commissioned and their actual performance is not known. Such low station heat rate parameters have, however, been witnessed in Dahanu TPS and Vijayavada TPS with performance levels of 97% and 94% respectively. As against this, the average performance of NTPC stations in 200/210 MW series is below 90%. NTPC in its letter dated 20.11.2003 has informed that the following NTPC generating stations, aggregating to a total capacity of around 7210 MW, having 210 and 500 MW units, are under execution/advanced stages of award: Talcher-II (4x500MW), Rihand-II (2x500MW), Ramagundam-III (1x500MW), Kahalgaon –II (3x500MW), Vindhyachal –III (2x500MW), Sipat- II (2x500MW), Unchahar-III (1x210MW). For all these generating stations, BHEL make 200 MW and 500 MW equipments are being supplied without any technological improvements. Sipat-I and Barh generating stations of NTPC (660 MW units) will be having super critical technology. It is expected that these generating stations of NTPC will be able to come only by 2006-07.

2.17 On above considerations, we are of the view that the gross station heat rate norms for new coal-based generating stations should be same as that of the existing coal-based generating stations. Thus, the station heat rate for existing and new coal based generating stations shall be as under:

**Table-2.5**

| Station Heat Rate Norm (kCal/kWh) | 200 /210 MW/ 250 MW Series | 500 MW Series |
|---|---|---|
| For Existing Stations | 2500 | 2450 |
| For New Stations | 2500 | 2450 |

**Note:** The station heat rate norm for 500 MW series shall be reduced by 40 kCal/kWh for electric driven Boiler Feed Pump and for the generating stations having a combination of 200/210/250 MW series and for 500 MW series, the station heat rate norm shall be weighted average station heat rate of above two series.

2.18 We also direct NTPC that for the generating stations like Sipat-I and Barh, having 660 MW unit size, NTPC shall make a separate proposal along with technical details to enable the Commission for determination of operational norms.

**Existing and New Lignite-based generating stations**

2.19 The normative heat rates and actual heat rates for the existing NLC generating stations for the period April 2001 to March 2003 as per data received, are summarised below:

**Table-2.6**

| Neyveli Lignite Corporation (NLC) | PLF | Normative HR kCal/kWh | Actual HR kCal/kWh |
|---|---|---|---|
| TPS-II St-I/ 630 MW | 81 | 2750 | 2997 |
| TPS-II St-II/ 840 MW | 77 | 2750 | 2862 |

2.20 As may be seen, the actual station heat rate is higher than the norm of 2750 kCal/kWh corresponding to 50% moisture. The reasons for high station heat rate despite performance level of 77% and 81% has neither been explained by NLC despite the opportunity made available to them, nor has it prayed for revision of the norms. As such, we are not inclined to change the existing station heat rate norms for the lignite- based stations along with the correction factor for moisture content in lignite as given in the existing notification dated 26.3.2001.

2.21 Like coal-based thermal technology, we do not anticipate any change on technology of the plant and equipment using lignite for power generation in the next 4-5 years. We are, therefore, keeping the station heat rate norms for the new lignite-based stations also at the same level as that of the existing lignite stations.

2.22 Accordingly, Station heat rate norms applicable to the existing as well as new stations of NLC shall be arrived at using the following multiplying factors on the gross station heat rate norms for the coal-based thermal power generating stations:

(i) For lignite having 50% moisture: Multiplying factor of 1.10

(ii) For lignite having 40% moisture: Multiplying factor of 1.07

(iii) For lignite having 30% moisture: Multiplying factor of 1.04

**(iv)** For other values of moisture content, multiplying factor shall be pro-rated for moisture content between 30%-40% and 40%-50% depending upon the rated values of multiplying factor for the respective range given under Clauses (I) to (iii) above.

## Gas/Liquid Fuel-based CCGT generating stations (other than small gas turbine stations)

## Existing Gas/Liquid Fuel-based CCGT generating stations

2.23 The normative heat rates and actual heat rates for NTPC and NEEPCO generating stations for the period April 2001 to March 2003 are summarised below:

**Table-2.7**

(In kCal/kWh)

| Name of Plant/ Capacity | PLF (%) | SHR Norm (In kCal/kWh) CC/OC | Actual Average SHR (In kCal/kWh) |
|---|---|---|---|
| **1** | **2** | **3** | **4** |
| **NTPC** | | | |
| Anta GPS/ 419.30 MW | 77 | 2125/3190 | 1947 |
| Auraiya GPS/ 663.36 MW | 78 | 2125/3190 | 2053 |
| Dadri GPS/ 829.84 MW | 77 | 2125/3190 | 1965 |
| Kawas GPS/ 656.20 MW | 71 | 2125/3190 | 1959 |
| Gandhar GPS/ 657.39 MW | 61 | 2125/3190 | 1966 |
| Faridabad GPS/431.58 MW | 74 | 2000/2900 | 1916 |
| Kayamkulam GPS/ 359.58 MW | 56 | 2000/2900 | 1994 |
| **NEEPCO** | | | |
| Assam GPS/ 291 MW | 49 | 2250/3225 | 2802 |
| Agartala GPS/ 84 MW | 75 | 3580 | 3623 |

(CC – Combined Cycle, OC – Open Cycle)

2.24 The gross station heat rate norms of the five NTPC generating stations, namely Anta, Auraiya, Kawas, Gandhar and Dadri were recommended by CEA vide letter No.3/NTPC/NORM/14/95-TTD/CEA/52 dated 18.3.1996 on the request of NTPC based on design details and actual operating data furnished by NTPC. These were adopted by the Central Government in respective project-specific tariff notification. The same norms were adopted by the Commission for the tariff period 2001-04.

2.25 It is understood that these generating stations were conceived originally with a station heat rate norm of 2000 kCal/kWh for combined cycle operation and 2900 kCal/kWh for open cycle operation in line with Central Government tariff notification of 30.3.1992. However, due to shortage of gas along HBJ pipe line and from the Gandhar gas field, lack of dual fuel-firing facility and non-availability of alternate fuel, leading to low operational level of these generating stations, the norms were reviewed and relaxed norms(Column 3 of the Table 2.7, except Kayamkulam and Faridabad GPS) were given. As can be seen from Table 2.7, the performance levels of these generating stations have since improved because of improved availability of gas, firming up of alternate fuel arrangement and provision of dual fuel-firing facilities in these generating stations.

2.26 NTPC has, however, brought out the impact of low schedule after ABT implementation for its gas-based or liquid fuel-based CCGT generating stations namely Anta, Auraiya and Kawas on account of separate scheduling on gas and liquid fuel, resulting in low dispatches for its gas-based/liquid fuel-based generating stations of the order of about 12%. In case of Gandhar GPS, NTPC has stated that low heat rate is on account of not resorting to water injection. NTPC has, therefore, sought continuation of the relaxed norms for its existing gas-based generating stations namely Anta, Auraiya, Dadri, Kawas and Gandhar GPS. In case of Dadri GPS, NTPC has stated that from October 2003, it is being scheduled at about 70% only. However, it has been observed that station heat rate is less than 2075 kCal/kWh despite despatches to the extent of 40% to 60% in Anta GPS and Kawas GPS. In case of Auraiya GPS, it is slightly less than 2100 kCal/kWh.

2.27 Keeping the above in view, we are of the opinion that there is scope for reducing heat rate norms for these five stations. We, therefore, prescribe the following station heat rate norms:

**Table-2.8**

| Name of Station | Combined cycle (kCal/kWh) | Open cycle (kCal/kWh |
|---|---|---|
| Gandhar GPS | 2000 | 2900 |
| Kawas GPS | 2075 | 3010 |
| Anta | 2075 | 3010 |
| Dadri | 2075 | 3010 |
| Auraiya | 2100 | 3045 |

2.28 The above norms shall be reviewed after two years of their implementation, having regard to operational performance under ABT.

2.29 In case of gas –based Faridabad GPS and liquid fuel-based Kayamkulam GPS actual station heat rates are close to the station heat rate norms even at a low performance level of 74% and 56%, respectively. As such we are not inclined to make any change in the station heat rate norms for these two stations and, therefore, the following norms should continue: -

**Table-2.9**

| Combined cycle | Open cycle |
|---|---|
| 2000 kCal/kWh | 2900 kCal/kWh |

**New Gas/Liquid Fuel Based Generating Stations**

2.30 APTRANSCO and APERC have stated in their submissions that the following station heat rate norms have been agreed to by the developers in the PPAs for new IPP projects in the State and approved by APERC and the same are better than Central Government norms of 1992:

**Table-2.10**

| **Name of Plants** | Capacity | SHR (kCal/kWh) |
|---|---|---|
| BAPL (BSES) | 220 MW | 1900 |
| Kona Seema | 445 MW | 1850 |
| Vemagiri | 370 MW | 1850 |
| Gauthami | 464 MW | 1850 |
| GVK Extn. | 200 MW | 1850 |

2.31 We are given to understand that lower station heat rate for the CCGT generating stations is on account of installation of advanced class machines.

2.32 Based on the gas turbine make, details as per Gas Turbine World Hand Book 2003, margins worked out based on gross station heat rate norms of 1850 kCal/kWh and 1900 kCal/kWh for gas-based/liquid fuel-based CCGT generating stations having gas turbines above 50 MW are as follows:

**Table-2.11**

| **A. E CLASS TECHNOLOGY GAS TURBINE COMB. CYCLE PLANTS** | | | | | | |
|---|---|---|---|---|---|---|
| Manufacturer | Module Configuration | Efficiency | Net Heat rate at ISO ( kCal/kWh) | Aux. Energy Consumption (%) for Module only | Gross Heat rate at ISO ( kCal/kWh) | % margin from SHR of 1900 kCal/kWh at site ambient conditions |
| BHEL | CC 209E | 51.70 | 1663.44 | 1.50 | 1688.77 | 12.51 |
| | CC309E | 52.00 | 1653.85 | 1.50 | 1679.03 | 13.16 |
| | CC3. 942 | 51.70 | 1663.44 | 1.50 | 1688.77 | 12.51 |
| SIEMENS | 3.V94.2 | 52.20 | 1647.51 | 1.50 | 1672.60 | 13.60 |
| MHI | MPCP2(M701) | 51.60 | 1666.67 | 1.50 | 1692.05 | 12.29 |
| | MPCP3(M701) | 51.80 | 1660.23 | 1.50 | 1685.51 | 12.73 |
| **B. EA/EC/E2 TECHNOLOGY GTS CC PLANT** | | | | | | |
| SIEMENS | 2.V94.2 A | 54.40 | 1580.88 | 1.50 | 1604.96 | 18.38 |
| GE | S209 EA | 52.70 | 1631.88 | 1.50 | 1656.73 | 14.68 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | S209EC | 54.40 | 1580.88 | 1.50 | 1604.96 | 18.38 |
| ABB ALSTHOM | 2x13E2-2 | 52.90 | 1625.71 | 1.50 | 1650.47 | 15.12 |
| | 2x13E2-3 | 52.90 | 1625.71 | 1.50 | 1650.47 | 15.12 |
| | | | | | | |
| **C. F/FA/A CLASS TECHNOLOGY GT CC PLANTS** | | | | | | |
| | | | | | | |
| ABB ALSTOM | KA-26 | 56.30 | 1527.53 | 1.50 | 1550.79 | 22.52 |
| GE | S109 FA | 56.70 | 1516.75 | 1.50 | 1539.85 | 23.39 |
| | S209 FA | 57.10 | 1506.13 | 1.50 | 1529.07 | 24.26 |
| MHI | MPCP1 (M701F) | 57.00 | 1508.77 | 1.50 | 1531.75 | 24.04 |
| | MPCP2 (M701F) | 57.30 | 1500.87 | 1.50 | 1523.73 | 24.69 |
| SIEMENS | 1S.V94.3A | 57.40 | 1498.26 | 1.50 | 1521.07 | 24.91 |
| | 2.V94.3A | 57.30 | 1500.87 | 1.50 | 1523.73 | 24.69 |
| BHEL | CC209EA | 55.70 | 1543.99 | 1.50 | 1567.50 | 21.21 |
| * THE APC HAS BEEN TAKEN ONLY FOR GT/ST MANUFACTURER'S SUPPLIED AUX. | | | | | | |

2.33 In our view, even with a station heat rate norm of 1900 kCal/kWh, sufficient margin exists to take care of degradation in heat rate on account of site ambient conditions, manufacturers margin, loading of units, aging, compressor fouling, etc.

2.34 We consider that only efficient machines to be commissioned in future. Also, with station heat rate norm of 1900 kCal/kWh, generating companies will have wider choice to optimise the configuration of the generating stations. Therefore, in case of new gas-based/liquid fuel-based generating stations, (except the small gas turbine generating stations having gas turbine of capacity of 50 MW and below) we approve the station heat rate norms to be adopted as follows:

| | |
|---|---|
| Open Cycle | 2755 kCal/kWh |
| Combined Cycle | 1900 kCal/kWh |

**Small Gas Turbine Power Generating Stations**

2.35 The normative heat rates and actual heat rates for NEEPCO generating stations for the period April 2001 to March 2003 are summarised below:

**Table-2.12**

(In kCal/kWh)

| **Name of Plant/ Capacity** | **PLF (%)** | **SHR Norm (In kCal/kWh) CC/OC** | **Actual Average SHR (In kCal/kWh)** |
|---|---|---|---|
| **1** | **2** | **3** | **4** |
| Assam GPS/ 291 MW | 49 | 2250/3225 | 2802 |
| Agartala GPS/ 84 MW | 75 | 3580 | 3623 |

(CC – Combined Cycle, OC – Open Cycle)

2.36 As can be seen from the Table-2.12 above, the station heat rate achieved by existing NEEPCO generating stations are higher than the norms. The existing norms for these generating stations are already relaxed norms as compared to the norms in this category. In case of small gas turbine generating stations having gas turbines of 50 MW and below, we are not making any change in the existing norms for small gas turbine stations prescribed under tariff notification dated 26.3.2001, as amended, as these norms were finalised recently and no change is contemplated in this short time. Accordingly, the following Station heat rate norms shall apply to existing as well as new small gas turbine generating stations:

(a) Assam Gas Based Power Station, Kathalguri

Open Cycle -- 3225 kCal/kWh
Combined Cycle -- 2250 kCal/kWh

(b) Agartala Gas Based Power Station, Ramachandranagar

Open Cycle -- 3580 kCal/kWh

(c) Other than (a) and (b) above

| | With Natural Gas | With Liquid Fuel |
|---|---|---|
| Open Cycle | 3125 kcal/kWh | 1.02 x 3125 kcal/kWh |
| Combined Cycle | 2030 kcal/kWh | 1.02 x 2030 kcal/kWh |

## Auxiliary Energy Consumption

**2.37** The auxiliary energy consumption norms vis-à-vis actual consumption for the coal-based generating stations of NTPC, lignite-based stations of NLC and gas-based/liquid fuel-based generating stations of NTPC and NEEPCO are as follows:

**Table-2.13**

| Type of Plant | Norm (%) | Actual (%) |
|---|---|---|
| **210 MW sets-Coal based** | | |
| Kahalgaon | 10.50 | 12.77 |
| Other NTPC generating stations in this series | 9.50 | 8.33 to 8.58 |
| **500 MW Sets-Coal based** | | |
| Rihand STPS | 9.00 | 8.02 |
| Talcher STPS | 8.00 | 7.82 |
| **Combination of 210 / 500 MW Sets-Coal based** | | |
| NTPC generating stations in this series | 8.25 | 5.7 – 6.8 |
| **210 MW – Lignite based** | | |
| TPS-II (St-I ) | 10.5 | 9.46 |
| TPS-II (St-II ) | 10.5 | 9.59 |
| **Gas/Liquid fuel based Station** | | |
| NTPC | | |
| Combined Cycle of NTPC | 3.00 | 1.70 to 2.70 |
| NEEPCO | | |
| Assam GPS (Combined Cycle) | 3.00 | 3.05 |
| Agaratal GPS (Open Cycle) | 1.00 | 1.53 |

2.38 It can be seen that almost in all cases, there is a margin of about 1% – 2% in coal-based generating stations of NTPC, except Kahalgaon STPS. In case of lignite- based TPS-II St-I & II of NLC , there is a margin of about 1%. In view of this, there is a scope for reduction in auxiliary power consumption by about 0.5% across the board for all the above existing coal-based/lignite-based generating stations, except Kahalgaon STPS. This will leave sufficient operational flexibility for the generator. High auxiliary energy consumption of 12.77% in Kahalgaon STPS is on account of abnormal auxiliary energy consumption in the quarter Jan 02 to Mar 02 of 35.43%. Ignoring this quarter, the auxiliary energy consumption for Kahalgaon STPS works out to 9.53%, against the existing relaxed norm of 10.50%. This is close to the existing normative auxiliary energy consumption of 9.5% for other stations, without cooling towers in this category despite low PLF of 69%. With the introduction of ABT in eastern region and open access and trading after the Electricity Act, 2003, it is expected that the dispatches from eastern region stations of NTPC would increase. We, therefore, feel that auxiliary energy consumption norm for Kahalgaon STPS should also be in line with other existing stations of NTPC in this series. Further, it has been stated by APERC and APTRANSCO that auxiliary energy consumption norms agreed with some of IPPs for the new coal-based and gas-based generating stations are about 0.5% less than the existing norms prescribed under the notification dated 26.3.2001. As such, for the new coal-based generating stations also, auxiliary energy consumption norm may be 0.5% less than the existing norms.

2.39 As regards new lignite-based generating stations, tariff petition of NLC for TPS-I (Expansion) is based on auxiliary energy consumption norm of 9.5%, which is comparable to the actual auxiliary energy consumption of TPS-II (Stage-I&II). As such, auxiliary energy consumption norms for the lignite-based generating stations may be higher by 0.5% of the auxiliary energy consumption norm of the coal-based generating stations.

2.40 In case of combined cycle generating stations of NTPC, there is a margin of about 0.3% – 1.2%. In case of NEEPCO stations, auxiliary energy consumption is more than the norms because of low dispatches of the generating stations due to low demand in the region. In order to give some operational flexibility to NTPC, especially having regard to low dispatches of liquid fuel-based generating stations of NTPC under ABT operation, we are not inclined to make any change in the auxiliary energy consumption norms of 3% for combined cycle operation and 1% for open cycle operation for NTPC generating stations. As regards NEEPCO stations in north-eastern region, we are expecting more dispatches with the introduction of ABT and open access and trading after the Electricity Act, 2003. As such, in their case also we are not inclined to make any change.

2.41 In view of paras 2.38, 2.39 and 2.40 above, the following auxiliary energy consumption norms shall apply :

(a) Existing & New Coal-based generating stations:

| | **With cooling tower** | **Without cooling tower** |
|---|---|---|
| 200 MW series | 9.0 per cent | 8.5 per cent |
| 500 MW series | | |
| Steam driven pumps | 7.5 per cent | 7.0 per cent |
| Electrically driven pumps | 9.0 per cent | 8.5 per cent |

(b) Existing & New Lignite based generating stations:

The auxiliary energy consumption norms for Lignite based Stations shall be 0.5% more than the above auxiliary energy consumption norms of coal based stations.

(c) Gas-based and Naphtha-based generating stations:

| | |
|---|---|
| Combined Cycle | 3.0 per cent |
| Open Cycle | 1.0 per cent |

**Specific Fuel Oil Consumption**

2.42 The actual specific fuel oil consumption for NTPC coal-based generating stations and NLC lignite-based generating stations is as follows:

**Table-2.14**

**(In ml/kWh)**

| Type of Plant | Norm | Actual |
|---|---|---|
| 210 MW / 500 MW (NTPC) | 3.5 | 0.21 – 0.62 |
| TPS-II (NLC) | 3.5 | 2.48 – 2.98 |

2.43 Specific fuel oil consumption for all NTPC generating stations is in the range of 0.21-0.62 ml/kWh, except Farakka where it is of the order of 1.62 ml/kwh because of low dispatches. The existing norm of specific oil consumption is 3.5 ml/ kWh. In case of NLC, the actual specific fuel oil consumption is between 2.48-2.98 ml/ kWh. In view of the above, there is a scope for downward revision of specific fuel oil consumption norms from 3.5 ml/ kWh to 2.0 ml/ kWh for all the existing as well as new coal-based generating stations of NTPC. For Kahalgaon STPS, there is no case for allowing higher specific fuel oil consumption norms of 7%. In case of NLC, specific fuel oil consumption norms may be reduced to 3.00 ml/kWh as agreed to by them at the open hearing. These norms shall be further reviewed after 2 years.

**Operational Norms for the Coal-based generating stations of 60MW/110 MW series**

2.44 There are two generating stations of NTPC, namely Tanda TPS and Talcher TPS which are having steam turbines of 60 MW and 110 MW. The Commission has finalised operational norms for these generating stations of NTPC recently while dealing with tariff petitions on case-to-case basis. Further, these generating stations are undergoing lot of R&M works and the Commission would not like to review the operational norms till the R&M works are completed. NTPC is directed to come before the Commission with a proposal on the revised operational norms after the completion of R&M works in these generating stations. As such, we hold that the operational norms of station heat rate, auxiliary energy consumption and specific fuel oil consumption prescribed by the Commission for the year 2003-04 in respect of above two generating stations of NTPC in the tariff orders for the previous tariff period up to 31.3.2004, shall continue to apply during the tariff period 2004-09 also, till R&M work in these stations is completed. These norms are:

**Table-2.15**

| Name of Station | Station Heat Rate Norm (kCal/kWh) | Aux. Energy Consumption Norm (%) | Specific Fuel Oil Consumption (ml/kWh) |
|---|---|---|---|
| Tanda TPS/ 440 MW | 3000 | 11 | 3.5 |
| Talcher TPS/ 460 MW | 3100 | 11 | 3.5 |

2.45 As regards new generating stations in the capacity range below 200 MW, we strongly feel that setting up of such generating stations needs to be discouraged due to high heat rate and as such, we are not specifying any norms for the low capacity generating stations,

**Adjustment as per actuals**

2.46 As discussed at para 2.2 above, the provision for actual or norms, whichever is lower, with respect to station heat rate, secondary fuel oil consumption and auxiliary energy consumption was retained in the tariff notification dated 26.3.2001 in order to maintain *status quo* at the relevant time. The beneficiaries have argued that there cannot be a profit element in the energy charges once the returns are assured to the generating company. The concern of the beneficiaries can be taken care of by reviewing the norms, from time to time, so that unduly high gains are not made by the generating companies by virtue of operational norms. In our opinion, in a performance-based system of regulation, adjustment based on actuals is not conducive to efficiency because there would be no incentive for generator to improve upon its efficiency of operation. As such the provision for adjustment of operating norms in relation to actuals shall be dispensed with.

**Stabilisation period and relaxed norms during stabilisation period:**

2.47 The Commission's tariff notification dated 26.3.2001 provides stabilization period commencing from the date of commercial operation to be reckoned as follows:

(a) Thermal (coal-based/lignite-based) generating stations - 180 days
(b) Open cycle gas-based and naphtha-based generating stations - 90 days
(c) Combined cycle gas-based and naphtha-based generating stations - 90 days

2.48 The notification provides for applicability of the relaxed norms of station heat rate, auxiliary energy consumption and specific fuel oil consumption during the stabilisation period in line with the provisions of Ministry of Power tariff notification dated 30.3.1992 and the tariff notification dated 26.3.2001. As we understand, stabilisation period was felt necessary because of lack of skilled manpower and lack of advanced training facilities and modern gadgets, requiring on-the-job training of operators to gain experience and skill in the efficient operation of units. Therefore, optimisation and tuning of various systems after the date of commercial operation used to take some time in the coal-fired units. With the addition of sufficient capacity and technological and Information Technology revolution, such on-the-job training is not necessary and optimisation and tuning of the systems should not take much time. Gas-based generating stations do not require elaborate process of optimisation and tuning at site. The Commission is, therefore, not in favour of providing any stabilisation period and applicability of the relaxed norms during stabilisation period. But the Commission does not want to take generators and developers by surprise without any notice to them. We are, therefore, allowing a period of two years from the date of implementation of revised tariff norms contained in this order beyond which the stabilisation period and the relaxed norms during stabilisation period would not be allowed. The relaxed operational norms allowed are:

(i) Station heat rate norm is relaxed by 100 kCal/kWh in case of coal-based/lignite-based generating stations. But there is no relaxation of station heat rate norm in case of gas-based/liquid fuel-based generating stations;

(ii) Auxiliary energy consumption norms are relaxed by 0.5% for coal-based/lignite-based generating stations as well as gas-based/liquid fuel-based generating stations; and

(iii) Specific fuel consumption norm of 5ml/kWh is applicable during stabilisation period as against 3.5 ml/kWh is subsequent to stabilisation period.

2.49 During the continuation of benefit of stabilisation period up to two years of implementation of revised tariff norms, the above dispensation of relaxed operational norms of station heat rate and auxiliary energy consumption shall continue but the specific fuel oil consumption norm of 4.5 ml/kWh shall be applicable instead of 5ml/kWh due to revision of specific fuel oil consumption norm subsequent to stabilisation period as 2 ml/kWh.

**Date of Commercial Operation**

2.50 The Commission's notification dated 26.3.2001 provides that the date of commercial operation of individual units shall be reckoned as follows: -

(a) Thermal (coal-based/lignite-based) generating stations: Not exceeding 180 days from the date of synchronization.

(b) Gas-based and naphtha-based generating stations: 90 days from the date of synchronization.

2.51 The above provision refers to date of synchronisation, which to our understanding has no relevance for tariff determination. For the purpose of tariff, the Commission is concerned with scheduled dates of commercial operation of respective units and the generating station and the actual dates of commercial operation of respective units and the generating station. In our opinion, the scheduled date of commercial operation in relation to a unit or the block or the generating station shall mean the date approved by the Board of Directors of the generating company or the Government (Ministry/Department/ Authority) or any other competent agency or the date arrived at by the Commission after taking into account the reasonable period in bringing the unit or the generating station into commercial operation from the date of placement of order for the main plant and equipment, having regard to the unit size, technology, etc.; and the actual date of commercial operation in relation to a unit shall mean date declared by the generator after demonstration of the Maximum Continuous Rating (MCR) or Installed Capacity (IC) through a successful trial run. The date of commercial operation of the generating station shall be reckoned from the date of commercial operation of the last unit of coal-based/lignite-based generating station or block of a combined cycle generating station. As such, the existing provision of the tariff notification dated 26.3.2001 shall be dispensed with and the following definitions of "Scheduled Commercial Operation Date" and "Actual Commercial Operation Date" shall be incorporated:

> **"Scheduled Commercial Operation Date"** in relation to a unit or the block or the generating station shall mean the date approved by the Board of Directors of the generating company or the Government (Ministry/Department/ Authority) or any other competent agency or the date arrived at by the Commission after taking into account the reasonable period in bringing the unit or the generating station into commercial operation from the date of placement of order for the main plant and equipment, having regard to the unit size, technology, etc.; and
>
> **"Actual Commercial Operation Date"** in relation to a unit shall mean date declared by the generator after demonstration of the Maximum Continuous Rating (MCR) or Installed Capacity (IC) through a successful trial run. The date of commercial operation of the generating station shall be reckoned from the date of commercial operation of the last unit of coal-based/lignite-based generating station or block of a combined cycle generating station.

**<u>HYDRO POWER GENERATING STATIONS</u>**

2.52 The operational norms of capacity index, auxiliary consumption, transformation losses and date of commercial operation of hydro power generating stations of the regulated central generating companies namely NHPC , NEEPCO, Satluj Jal Vidyut Nigam, Narmada Hydroelectric Development Corporation, etc. are governed, at present, by the Commission's tariff notification dated 26.3.2001, applicable for the tariff period 1.4.2001 to 31.3.2004, which are summarised below:

1. Normative Capacity Index: 85%
2. Auxiliary Energy Consumption

   (a) Surface hydro power generating stations with rotating exciters mounted on the generator shaft - 0.2% of energy generated

   (b) Surface hydro power generating stations with static excitation system - 0.5% of energy generated

   (c) Underground hydro power generating stations with rotating exciters mounted on the generator shaft - 0.4% of energy generated

   (d) Underground hydro power generating stations with static excitation system - 0.7% of energy generated.

3. Transformation losses

   From generation voltage to transmission voltage - 0.5 percent of energy generated.

4. Date of Commercial Operation

   Not exceeding 15 days from the date of synchronization.

**Operational norms for next tariff period**

**Capacity Index**

2.53 The concept of capacity index was introduced by the Commission for the first time for the current tariff period 1.4.2001 to 31.3.2004, in lieu of generating station availability. The capacity index is a measure of the generating station's availability with the availability of water for generation. The basis for introduction of the concept of capacity index was:

(a) Water spillage must be minimized, and

(b) As far as possible peaking capacity of each hydro power generating station should be available when it is most required by the system, that is, during the peak demand period.

The normative value of the capacity index during the current tariff had been fixed at 85% for all types of hydro power generating stations.

**Views of Stakeholders**:

2.54 Although the capacity index concept is only 2 ½ years old, most of the stakeholders have favoured its continuation during the next tariff period but have suggested raising the annual target of the capacity index, matching it with the actual performance achieved during the last 2-3 years. The views of various stakeholders on the Discussion Paper and also during the open hearing on terms and conditions of tariff for the next tariff period are summarized below:

(a) BBMB has stated that the normative capacity index for run-of-river generating stations should be higher than reservoir-based generating stations, because-

(i) For run-of-river generating stations inflows during the lean period are inadequate, can manage to take machines under scheduled maintenance without affecting the capacity index.

(ii) For storage-based generating stations all the machines are required to operate for three hours during the peak period. Machines taken under planned shut down during lean inflow period will result in reduction in the capacity index.

(b) PSEB has suggested revision of the normative capacity index to 90% based on actual performance of hydro power generating stations.

(c) RVPNL has suggested that normative capacity index should be raised to 90% for recovery of full capacity charges.

(d) Bharat Chambers of Commerce has suggested that the normative capacity index should not be below 90%.

(e) DVC, Assam State Electricity Board, Kerala Electricity Regulatory Commission and Bengal Chambers of Commerce have suggested that the normative value of the capacity index at 85% may be continued.

2.55 We have analyzed the performance of NHPC generating stations during the past 2½ years and have found that in case of purely run-of –river generating stations like Tanakpur and Uri, the value of the capacity index achieved is as high as 99% and for pondage and storage-based generating stations, like Chamera and Baira Siul, the average capacity index achieved has been of the order of 95%. The capacity index achieved at various generating stations of NHPC during 2001-02 to 2003-04 is summarised in the table given below:

**Table-2.16**

| HE Station | Installed Capacity (MW) | **Capacity Index (%)** | | |
|---|---|---|---|---|
| | | 2001-02 | 2002-03 | 2003-04* |
| Chamera(P) | 540 | 94.2 | 96.6 | 96.5 |
| Tanakpur(R) | 94.2 | 96.1 | 99.7 | 100 |
| Baira siul (P) | 198 | 96.3 | 96.3 | 99.3 |
| Uri (R) | 480 | 94.0 | 99.2 | 100 |
| Salal (R) | 690 | 97.0 | 95.2 | 99.8 |

R- Purely Run-of -River, P- ROR with pondage
(*) – Cumulative Capacity Index achieved up to September 2003.

2.56 We find merit in the suggestion of BBMB to have the lower target for pondage and storage type generating stations compared to purely run-of-river generating stations, so as to encourage construction of more generating stations of the former type in future to provide valuable peak power to the system. We also find merit in the suggestions made by the stakeholders to have future benchmarks commensurate with actual performance of the hydro power generating stations. Accordingly, we propose to increase the annual normative capacity index of purely run-of-river type hydro power generating stations from the present value of 85% to 90%. However, for storage and pondage type of the generating stations, the annual normative capacity index will remain at 85%. The normative benchmarks of capacity index proposed for the next tariff period are:

| | |
|---|---|
| For purely run-of-river type generating stations | = 90% |
| For pondage and storage type generating stations | = 85% |

Relaxation in the capacity index during first year of operation of newly-commissioned hydro power generating stations

2.57 It has been brought to our notice by NHPC that certain common teething problems have been encountered by them after commissioning of the generating stations, which include the problems faced in two of their newly commissioned hydro power generating stations viz. Rangit (3x20 MW) in Sikkim and Chamera Stage-II (3x100 MW) in Himachal Pradesh. These are summarised below :

(a) In hydroelectric projects after filling of reservoir, experience has shown that there are landslides during the period when the rock/catchments areas get settled. This is an inherent feature in the geology; especially in the northern part of India because of poor saturation of the adjoining land mass. These events occur within 10 – 12 months after the reservoir filling and during initial operation of the reservoir for generation and silt flushing. This results in forced outage of machines/closure of the generating stations and reduced output for rectification and strengthening works of structures, hill slopes, cavities, etc.

(b) During the first filling up of reservoir, the inflow of silt is usually much more than the anticipation and leads to numerous problems, like accumulation of silt in the reservoir, silt ejectors getting choked with abnormally high levels of silt due to choking of hoppers. Consequently, silt flushing or dredging requires shutdown of the power generating station. This unexpected quantity of silt chokes the coolers, damages sealing equipments also thereby causing forced outages of the machines till the design of the equipments is reviewed and additional arrangements are made to avoid passing of silt through the machines.

2.58 Keeping the above natural causes in view, which are beyond the control of hydro power plant operators, we propose to reduce the normative value of capacity index by 5% for all types of hydro power generating stations, only during the first year of operation. The period of one year is based on the consideration that it provides breathing time to make appropriate arrangements to overcome the problems of the kind noticed above.

2.59 The normative value of capacity index during the first year of operation shall accordingly be as follows:

Purely run-of-river type generating station - 85%
Storage and pondage type generating station - 80%

2.60 Although the normative capacity index has been fixed at 85% for purely run-of-river (ROR) and 80% for ROR with pondage or storage type of hydro power generating stations for recovery of full capacity charges for the first year of operation of a newly commissioned hydro power generating station, incentive shall be payable only above the normative capacity index of 90% for purely run-of-river (ROR) and 85% for ROR with pondage or storage type of hydro power generating stations.

In case the normative capacity index is not achieved during the year, recovery of capacity charges below the level of normative capacity index shall be on prorata basis.

**Auxiliary consumption and Transformation losses**

2.61 No evidence has been placed before the Commission to indicate that the existing norms for Auxiliary consumption and Transformation losses are unsatisfactory. As such, we do not propose any amendment in the norms for Auxiliary consumption and Transformation losses during the next tariff period. These would continue to be as under:

**Auxiliary Energy Consumption**

(a) Surface hydro power generating stations with rotating exciters mounted on the generator shaft - 0.2% of energy generated

(b) Surface hydro power generating stations with static excitation system - 0.5% of energy generated

(c) Underground hydro power generating stations with rotating exciters mounted on the generator shaft - 0.4% of energy generated

(d) Underground hydro power generating stations with static excitation system - 0.7% of energy generated.

**Transformation losses**

From generation voltage to transmission voltage - 0.5 percent of energy generated.

**Date of Commercial Operation**

2.62 The Commission's notification dated 26.3.2001 provides that the date of commercial operation of individual units shall not exceed 15 days from the date of synchronization. The above provision refers to date of synchronization, which to our understanding has no relevance to tariff determination. As discussed in para 2.59 above for thermal generating stations, the Commission is concerned with the scheduled dates of commercial operation of respective units and the generating station and also the actual dates of commercial operation of respective units and the generating station for the purpose of tariff. In our opinion, here also, the scheduled date of commercial operation in relation to a unit or the station shall mean the date approved by the Board of Directors of the generating company or the Government (Ministry/Department/ Authority) or any other competent agency or the date arrived at by the Commission taking into account the reasonable period in bringing the unit or the station into commercial operation from the date of placement of order for the main plant and equipment having regard to the unit size, technology, etc.; and the actual date of commercial operation in relation to a Unit shall mean date declared by the generator after demonstration of the Maximum Continuous Rating (MCR) or Installed Capacity (IC) through a successful trial run. The date of commercial operation of the generating station shall be reckoned from the date of commercial operation of the last unit of the generating station. As such, the existing provision of the tariff notification dated 26.3.2001 shall be dispensed with and the following definitions of “Scheduled Commercial Operation Date” and “Actual Commercial Operation Date” shall be incorporated:

> **“Scheduled Commercial Operation Date”** in relation to a unit or the station shall mean the date approved by the Board of Directors of the generating company or the Government (Ministry/Department/ Authority) or any other competent agency or the date arrived at by the Commission taking into account the reasonable period in bringing the unit or the station into commercial operation from the date of placement of order for the main plant and equipment, having regard to the unit size, technology, etc; and
>
> **“Actual Commercial Operation Date”** in relation to a Unit shall mean date declared by the generator after demonstration of the Maximum Continuous Rating (MCR) or Installed Capacity (IC) through a successful trial run. The date of commercial operation of the generating station shall be reckoned from the date of commercial operation of the last unit of power station.

## INTER-STATE TRANSMISSION

**Target Availability**

**Existing Provision**

2.63 The Commission vide its order dated 8th December, 2000 had enhanced normative availability for recovery of full transmission charges as well as payment of incentive from 95% specified by Ministry of Power to 98%. This increase was keeping in view recommendations of the Expert Committee constituted by the Central Government to make recommendations on the framework to facilitate private investment in the transmission sector as also recommendations of CEA based on the study carried out on historical data of some of the utilities, including POWERGRID.

**Views of stakeholders**

2.64 The views of the stakeholders, in respect of availability and incentive are summarised below:

(a) APERC has stated that target availability should be enhanced to 98.5% and the existing pattern of incentive should continue.

(b) According to GEB, availability of transmission system of the State Electricity Boards is of the order of 98%. In view of this, it has suggested that target availability of national utility should be close to 100% and no separate incentive is necessary. TNEB has contended that the transmission line being static equipment, availability above 99% is easily achievable.

(c) According to TNEB, cost of transmission system includes emergency restoration system, hotline tools and towers designed with higher factor of safety. Further, TNEB has opined that due to expansion of grid, alternate corridor for transfer of power are available in case of break down. In view of this, TNEB has suggested that recovery of full transmission charges should take place at 99%. In view of the frequent failures of converter transformers, TNEB has suggested target availability of 98% for HVDC stations. TNEB is of the opinion that no incentive should be paid for achieving availability above target availability. It has also stated that POWERGRID has achieved availability of more than 99.5% in all the regions for the past five years.

(d) TNERC has also suggested target availability of 99% for recovery of full transmission charges and no incentive should be payable beyond target availability.

(e) RVPNL and HPERC have also suggested target availability of 99% in view of the past performance. RVPNL has further observed that availability of important lines and sub-stations, such as Rihand-Dadri HVDC link should be given more weightage and availability of HVDC link should be ensured separately.

(f) MPSEB has also expressed similar views. It has further argued that there should not be any element of incentive as the operation of the transmission system is of fixed assets and the cost of assets is being met out from tariff.

(g) CSEB, GERC, GRIDCO, Bengal National Chamber of Commerce & Industry and WBSEB have suggested continuation of the existing norms for payment of incentive.

(h) GRIDCO has suggested additional norm for percentage transmission loss as fixed by State Electricity Regulatory Commissions for state transmission agencies.

(i) BSEB has suggested that no incentive should be payable above the target availability of 98%. It has further suggested charging of disincentive if transmission loss exceed reasonable limit of 2.5%.

(j) PSEB has argued against reduction in normative availability below 98%. It has accepted the present rate of incentive, but has felt need for reviewing methodology for calculating availability as according to PSEB lines whether at the tail end or connected to generating stations are given same weightage.

(k) RERC has supported continuation of incentive based on availability of transmission system as otherwise maintenance may get affected. It has further suggested linking of incentive/disincentive to achieving target of transmission loss.

(l) Bharat Chamber of Commerce has argued against providing incentive to transmission utilities beyond the target availability unless transmission companies share the financial loss of beneficiaries arising out of non-availability of transmission lines and other transmission constraints.

(m) Utkal Chamber of Commerce and Industry has also argued against incentive for transmission system because in its opinion there is no contribution of investor in increasing the availability.

(n) Shri R.K. Narayan has argued for availability of 97.5% so that the staff working in the transmission utilities may also get incentive comparable to their counterpart in the generating company.

(o) POWERGRID has refuted objections of some beneficiaries for payment of incentive. POWERGRID has stated that the Commission has decided in favour of need for incentive in transmission sector after discussing the issue threadbare during hearings. It has also quoted from the Commission's orders to support its claim for continuation of incentive. POWERGRID has suggested that target availability for recovery of full transmission charges should be 95% and incentive should be payable beyond this level. According to POWERGRID, level of 95% in Ministry of Power notification was fixed on the recommendation of CEA. POWERGRID has stated that it may not be possible to maintain availability above 98% due to aging of the transmission system, HVDC lines and poles whose availability is otherwise lower due to various factors. POWERGRID has suggested slab-based incentive @ 1% of equity for every 1% rise in availability above 95%. It has also suggested that the provision for payment of disincentive should be omitted or disincentive should be applied at the same rate as applicable for incentive. POWERGRID has urged that in case benchmark of 95% is not acceptable, incentive @ 1% of equity for every 0.5% rise in availability above 98% for lines other than HVDC and @ 1% of the equity for every 1% rise in availability above 95% for HVDC lines may be considered. It has, however, insisted that benchmark for disincentive should be kept at 95%.

**Analysis**

2.65 On the issue of fixation of target availability, we would like to base our findings on the actual availability achieved during the recent past. The table below shows, the actual availability of POWERGRID system for Northern, Western, Southern and Eastern Regions for the period 1997-98 to 2001-02:

**Table-2.17**

| REGION | YEAR | AVAILABILITY | AVERAGE |
|---|---|---|---|
| Eastern | 97-98 | 98.26 | |
| Region | 98-99 | 99.51 | |
| | 99-00 | 99.02 | |
| | 00-01 | 99.24 | |
| | 01-02 | 98.46 | 98.898 |
| Southern | 97-98 | 99.6 | |
| Region | 98-99 | 99.53 | |
| | 99-00 | 99.67 | |
| | 00-01 | 99.68 | |
| | 01-02 | 99.72 | 99.64 |
| Northern | 97-98 | 99.3 | |
| Region | 98-99 | 99.02 | |
| | 99-00 | 99.04 | |
| | 00-01 | 97.54 | |
| | 01-02 | 98.65 | 98.71 |
| Western | 97-98 | 99.36 | |
| Region | 98-99 | 99.45 | |
| | 99-00 | 99.63 | |
| | 00-01 | 98.63 | |
| | 01-02 | 98.52 | 99.12 |
| ALL INDIA | | | 99.09 |

2.66 It is seen from the above table that the average availability for all the regions is above 98% and average of all the four regions is about 99.1%. Of the 20 values, the lowest and the only value below 98% is for the Northern Region for the year 2000-01. Thus, in our opinion there is no ground for lowering the target availability below 98% as sought by POWERGRID. Similarly, any increase in the target availability as suggested by some of the stakeholders, will leave no room for operational flexibility, maintenance etc. We, therefore, direct for continuation of the target availability at the existing level of 98% for recovery of full transmission charges during the tariff period 2004-09 as well.

2.67 Some of the stakeholders, including POWERGRID have sought separate treatment for HVDC assets. We are not in favour of any such special treatment. HVDC assets are part of regional assets for which the information regarding actual availability is tabulated in Table - 2.17. Since we have fixed the target availability on consideration of the actual availability of the regional transmission system, it automatically takes care of HVDC as well as HVAC assets. If a separate lower target availability is to be specified for HVDC assets, the target availability for the HVAC assets will have to be enhanced based on the past performance. This will only make the procedure more cumbersome, without any corresponding benefit either to the beneficiaries or to the transmission service provider. Further, POWERGRID has not submitted any factual details to substantiate its claim for a separate lower availability for HVDC systems. In view of these factors, we direct that HVDC assets shall continue to be clubbed with HVAC assets for calculation of availability.

2.68 Some of the stakeholders have suggested weightage to lines according to their importance. We may point out that the procedure approved by the Commission vide order dated 26$^{th}$ September 2000 takes into account this aspect. It, *inter alia,* stipulates weightage equal to Surge Impedance Loading (rated MW capacity in case of HVDC line) multiplied by the ckt-Km for the lines and weightage equal to MVA capacity to ICT bank. The availability numbers given in Table - 2.17, have been calculated on the above principles and, therefore, the issues raised by the stakeholders have been taken care of. We, therefore, direct that the procedure as laid down under the Commission's order dated 26th September, 2000 shall be continued to be applied for calculation of availability during the next tariff period as well. (The detailed procedure in this regard is already enclosed as Appendix III to the Draft Regulation).

**Auxiliary Power Consumption in the Sub-station**

**Existing Provision**

2.69 As per notification dated 26th March, 2001, the norms for Auxiliary Power Consumption are as under:

(i) <u>Auxiliary Power Consumption in the Sub-Station:</u>

(a) AC System - NIL

Note: The auxiliary consumption in the AC sub-station for the purpose of air-conditioning, lighting, technical consumption, etc. shall be borne by the transmission utility as part of its operation & maintenance expenses.

(b) For HVDC Sub-station -

For Auxiliary power consumption in HVDC stations GoI shall allocate appropriate share from the ISGS / Central Power Stations in the region. Fixed charges for such power shall be borne by the beneficiaries of the region and ISGS shall bill the Transmission Utility only for the variable charges.

The stakeholders have not furnished any comments on this issue. In so far as AC system is concerned, the Commission is of the view that the present system is working satisfactorily and there is no need to introduce any change. The Commission, therefore, does not propose any amendment to norms for auxiliary consumption for AC system for the next tariff period i.e 2004-09. However, regarding sharing of the fixed charges for the power allocated by the Central Government for Auxiliary power consumption in HVDC stations, we may clarify that the fixed charges shall be borne by the beneficiaries of the region in case of intra-regional assets and by the beneficiaries of the connected regions in case of inter-regional assets in proportion to transmission charges.

**Transmission losses**

2.70 At present the Commission has not prescribed any norms for transmission losses. These are computed by the REB/RLDC and allocated to various beneficiaries. The arrangement is working satisfactorily and, therefore, the Commission does not propose to change the existing arrangement. It may, however, be mentioned that in so far as allocation of losses in the open access is concerned, the same is being covered in the regulations on Open Access, separately.

2.71 It may be pertinent to point out that the operational norms decided by us in this chapter are the ceiling norms and the State utilities can always negotiate better operational norms with the advent of new technology and efficiency improvement in the new designs.

# CHAPTER 3

## Operation & Maintenance Expenses

### THERMAL POWER GENERATING STATIONS

### Existing Provisions

3.1 In accordance with the terms and conditions of tariff presently in force, the operation and maintenance expenses of thermal power generating stations in operation for more than five years as on 1.4.2001 are regulated based on actual O&M expenses incurred for these generating stations for the years 1995-1996 to 1999-2000. The actual O&M expenses for these five years are normalized and the average expenses after normalization form the base O&M expenses for the year 1997-1998 which are further escalated at the rate of 10% per annum up to 1999-2000 and thereafter at the rate of 6% per annum to arrive at the normative O&M expenses for the respective year during the tariff period. For the generating stations in operation for less than five years on 1.4.2001, the base O&M charges are fixed at 2.5% of the capital cost in the first year of operation, with 10% annual escalation in subsequent years up to 1999-2000. The rate of escalation is taken as 6% to arrive at the base figure for 2000-01. During the tariff period, O&M expenses for respective year are computed by applying the escalation factor of 6% over O&M expenses for the previous year. A deviation of escalation factor computed for actual data that lies within 20% of the notified escalation factor (which works out to 1.2% on either side of 6%) is to be absorbed by the generating company. The deviations beyond this limit are to be adjusted on the basis of actual escalation factor for which the utility concerned is to approach the Commission separately.

**Actual Vs Normative O&M Expenses**

3.2 The Discussion Paper had debated whether it would be advisable to move away from "actual" to "normative" O&M expenses. The Discussion Paper flags two options for the normative O&M expenses:

(a) As a percentage of capital cost, and
(b) As a benchmark cost per MW.

**Views of Stakeholders**

3.3 A perusal of comments/suggestions received from the stakeholders, i.e. the regulated entities, state generating utilities, beneficiaries/state transmission utilities, financial institutions and IPPs, shows that most of them are in favour of adoption of normative O&M either as a percentage of project cost or in terms of Rs./MW. However, different entities have varied perception, as summarised below:

(a) WBSEB, APTRANSCO, MPERC, etc. have sought adoption of normative O&M and adjustment based on actuals if the actuals are the lower than the normative.

(b) The generating companies like NTPC and IPPs have sought separate norms for the coal-based generating stations and gas-based generating stations. According to them, the norm of 2.5% of the capital cost is not sufficient. Beneficiaries on the other hand, have sought O&M expenses at 2.5 per cent of project cost to be continued along with escalation rate in line with weighted price indices as per the Commission's present notification dated 26.3.2001.

(c) NTPC has sought 3.5% of the current capital cost for the coal-based generating stations and 5% of the current capital cost for the gas-based generating stations. Alternatively under the second option, NTPC has sought following O&M cost in Rs./MW:

| | | |
|---|---|---|
| 200 MW | - | Rs.15.4 lakh/MW/year |
| 500 MW | - | Rs.14.0 lakh/MW/year |
| Alternatively for all | | |
| 200 & 500 MW units | - | Rs.15.0 lakh/MW/year |
| Gas-based generating station | - | Rs.17.5 lakh/MW/year |

However, during open hearing NTPC suggested the following O&M cost norms as percentage of current capital cost :

**<u>Coal-based generating stations</u>**

2.5% for generating stations up to 10 years
3% for generating stations of 10 years to 20 years
3.5% for generating stations > 20 years.

**<u>Gas-based generating stations</u>**

3% for generating stations upto 5 years
4% for generating stations of 5 years to 10 years
5% for generating stations > 10 years

For liquid fuel-based generating stations, additional 0.5% over gas-based generating stations has been sought. Further, NTPC has demanded that O&M charges during the tariff period may be provided based on 10% escalation.

(d) BSES has stated that O&M cost should be on a normative basis as a given percentage of the normative project cost. Linking O&M expenses to the actual project cost leads to wide variation for similar type of projects. The actual O&M expenses (including Insurance) are found to be more than those allowed in the existing norms, particularly for gas-based generating stations. BSES has suggested O&M expenses (first year) allowed should be 4.25% for gas-based generating stations and 3% for coal–based generating stations of the normative project cost. As regards year-to-year escalation factor, according to BSES, a suitable weighted average of WPI and CPI may be used (say 60% WPI and 40% CPI).

(e) DVC and CESC have sought 3.5% of capital cost for the coal-based generating stations. GPEC has also sought 2.5% to 3% for the coal-based generating stations and 5% of the capital cost for the gas turbine power generating stations. CII has sought 4% of the capital cost for coal-based generating stations.

(f) UPPCL, APTRANSCO , Kerala SEB, KPTCL, HPERC, TNERC, KERC, PSEB are inclined towards adoption of normative O&M expenses by benchmarking of O&M expenses in terms of Cost/MW.

(g) Most of the beneficiaries have sought for reduction in annual escalation rate and have suggested that it should be based on weighted average of WPI and CPI for the respective year. UPPCL has also stated that the utility should be asked to provide for justification when the increase in O&M expenses for the previous year is more than weighted average of WPI and CPI for the respective year. The generating companies and IPPs on the other hand have sought an escalation rate of 10% or more to cover inflation as well as aging of the generating stations,

(h) The financial institutions are more concerned about the adequacy of O&M charges and have sought O&M expenses based on actuals. IDBI on the other hand has sought O&M cost based on norms or actual, whichever is lower.

**Choice of Methodology for O&M Expenses**

3.4 There is, thus, an overwhelming consensus in favour of moving away from actual to normative O&M expenses. The Commission is also of the view that there is no incentive for the generating company to optimise its operation if O&M expenses are based on actuals. In other words, it would lead to wastage of natural resources in the ultimate analysis. As against this, the normative O&M expenses offer an incentive to the generating companies to optimise operational efficiencies in order to maximise their earnings and savings.

3.5 Having settled the issues that adoption of normative O&M expenses is a better route, it leaves us to explore whether the norms should be as a percentage of capital cost or a benchmark cost per MW.

3.6 The option of linking normative O&M expenses to capital cost will require ascertaining the base capital cost. O&M charges would have to be revised based on additional capitalisation from time to time. O&M charges would become high in case the capital expenditure is more on account of time and cost over run. NTPC has suggested the linking of O&M expenses to current capital cost . The Commission had foreseen difficulty in linking the normative O&M expenses to the capital cost in its order dated 21 December, 2000 on tariff norms as follows:

*"4.3.6 The Commission is convinced that linking the base level O&M expenses to the capital cost is not appropriate as there are unresolved issues of measurement of the capital cost itself. Thus, the efficacy of the base on the basis of capital cost is questionable."*

*"4.4.5 The Commission recognizes the problems associated with the measurement of capital cost of old projects and the computation of base O&M expenses as a proportion of fixed cost. This issue was widely debated in the hearings. NHPC's attempt to prove that actual O&M expenses as a percentage of capital cost are insufficient is not very appropriate as the measurement of capital cost is faulty. They have inflated the original capital cost (the capital cost at the time of commissioning of the project) by 6.5 percent per annum to arrive at year-wise estimates of capital cost."*

3.7 In view of the complexities in the measurement of the capital cost, linking the base level O&M expenses to the capital cost may not be appropriate. In order to discourage over-capitalisation, O&M charges of the project may not be linked to the capital cost. In case of old power stations, it may be difficult to work out O&M charges on the basis of capital cost of the project. O&M charges based on capital cost could result in anomalies where there is wide variation in the project capital cost due to abnormal time and cost over run, etc. It is rational to assume that for a similar power station, O&M charges are of the same magnitude, irrespective of its exact capital cost. The normative O&M expenses in terms of Cost/MW could be conveniently followed by the states. We accordingly feel that it is desirable to apply O&M cost norms in terms of Rs. Lakh/ MW for the existing as well as the new thermal power generating stations.

**<u>Actual O&M Cost Data of Existing Generating Stations and bench marking of O&M cost norms in per MW term:</u>**

3.8 For the purpose of benchmarking O&M cost values under the second option, the Commission sought O&M data of some of the good operating generating stations, namely Trombay, Daharua, Vijayawada, Anpara, Bhatinda, Wanakbori and Chanderpur vide letter dated 17.7.2003. O&M cost data of NTPC generating stations and NEEPCO for the period up to 2000-01 has been taken from the information furnished by them to the Commission in various tariff petitions. O&M expenses have been considered in respect of the following components of the thermal power generating station:

(a) Repair & Maintenance,
(b) Stores Consumed,
(c) Employees cost,
(d) Power charges,
(e) Security expenses,
(f) Water charges,
(g) Professional expenses,
(h) Communication expenses,
(i) Travelling expenses,
(j) Insurance,
(k) Rent,

(l) Printing & Stationary,
(m) Other miscellaneous expenses, and
(n) Corporate office expenses allocated to the generating station.

O&M cost data for NLC had not been made available.

3.9 The actual O&M expenses of coal-based generating stations of NTPC and some of the comparable generating stations of SEBs/IPPs are as follows:-

**Table-3.1**

| Sl No. | Name of the station/ Configuration | 1995-96 | 1996-97 | 1997-98 | 1998-99 | 1999-00 | 2000-01 |
|---|---|---|---|---|---|---|---|
| **A** | **200 MW/210 MW/250 MW Series** | | | | | | |
| 1 | **Dadri Thermal (NCTPS)/ (4x210 MW- 840 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 4259 | 6076 | 6756 | 8224 | 9738 | 11459 |
| | O&M Expenses in Rs. Lakh/MW | 5.07 | 7.23 | 8.04 | 9.79 | 11.59 | 13.64 |
| 2 | **FGUTPS St- I/ (2 x 210 MW-420 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 3678 | 4728 | 4530 | 5737 | 7244 | 8910 |
| | O&M Expenses in Rs. Lakh/MW | 8.76 | 11.26 | 10.78 | 13.66 | 17.25 | 21.22 |
| 3 | **Vindhyachal STPS St-I/(6x210 MW- 1260 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 7442 | 7064 | 9821 | 11275 | 12087 | 21469 |
| | O&M Expenses in Rs. Lakh/MW | 5.91 | 5.61 | 7.79 | 8.95 | 9.59 | 17.04 |
| 4 | **Kahalgaon STPS/(4x210 MW- 840 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | | 5721 | 7096 | 7907 | 8096 | NA |
| | O&M Expenses in Rs. Lakh/MW | | 6.81 | 8.45 | 9.41 | 9.64 | NA |
| 5 | **Vijawawada TPS/ (6 X 210 MW- 1260 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 3813 | 4485 | 5182 | 6238 | 9679 | 8031 |
| | O&M Expenses in Rs. Lakh/MW | 3.03 | 3.56 | 4.11 | 4.95 | 7.68 | 6.37 |
| 6 | **Khaperkheda TPS/ (4x210 MW- 840 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 4202 | 4645 | 3640 | 4517 | 4647 | 13559 |
| | O&M Expenses in Rs. Lakh/MW | 10.01 | 11.06 | 8.67 | 10.75 | 11.06 | 16.14 |
| 7 | **Guru Gobind Singh Super Thermal Plant/ (6 x 210 MW-1260 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 4357 | 5650 | 6104 | 7956 | 8623 | 9277 |
| | O&M Expenses in Rs. Lakh/MW | 3.46 | 4.48 | 4.84 | 6.31 | 6.84 | 7.36 |
| 8 | **Wanakbori TPS/ (6 x 210 MW- 1260 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 3812 | 4383 | 5506 | 4174 | 5592 | 5651 |
| | O&M Expenses in Rs. Lakh/MW | 3.03 | 3.48 | 4.37 | 3.31 | 4.44 | 4.48 |
| | | | | | | | |
| **B** | **200 MW/210 MW/250 MW /500 MW Series** | | | | | | |
| 1 | **Singarauli STPS/(5 x 200 MW+ 2 x 500 MW-2000 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 10348 | 10769 | 16189 | 16151 | 21929 | 17097 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | O&M Expenses in Rs. Lakh/MW | 5.17 | 5.38 | 8.09 | 8.08 | 10.96 | 8.55 |
| 2 | **Korba STPS/(3x200 MW+3x500 MW- 2100 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 9936 | 10427 | 12299 | 13322 | 14644 | 15928 |
| | O&M Expenses in Rs. Lakh/MW | 4.73 | 4.97 | 5.86 | 6.34 | 6.97 | 7.58 |
| 3 | **Ramagundam STPS/ (3x200 MW+3x500 MW-2100 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 10214 | 10469 | 11894 | 13874 | 16055 | 18421 |
| | O&M Expenses in Rs. Lakh/MW | 4.86 | 4.99 | 5.66 | 6.61 | 7.65 | 8.77 |
| 4 | **Farakka STPS/ (3x200 MW+2x500 MW-1600)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 8090 | 10805 | 11704 | 13382 | 15428 | 18350 |
| | O&M Expenses in Rs. Lakh/MW | 5.06 | 6.75 | 7.32 | 8.36 | 9.64 | 11.47 |
| 5 | **Chandrapur TPS/ (4x210 MW + 3x500 MW-2340 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 11631 | 14916 | 14916 | 18989 | 18402 | 20443 |
| | O&M Expenses in Rs. Lakh/MW | 6.32 | 8.11 | 6.37 | 8.12 | 7.86 | 8.74 |
| **C** | **500 MW plants** | | | | | | |
| 1 | **Rihand STPS/ (2x500 MW- 1000)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 5658 | 7446 | 8716 | 9059 | 8899 | 10052 |
| | O&M Expenses in Rs. Lakh/MW | 5.66 | 7.45 | 8.72 | 9.06 | 8.90 | 10.05 |
| 2 | **Talcher STPS/ (2x500 MW- 1000 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | | | 4999 | 5990 | 6391 | NA |
| | O&M Expenses in Rs. Lakh/MW | | | 5.00 | 5.99 | 6.39 | NA |
| 3 | **Trombay Thermal Stations/ (2x500 MW + 150 MW CCGT-1350 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 11721 | 11086 | 13961 | 14111 | 14927 | 12941 |
| | O&M Expenses in Rs. Lakh/MW | 8.68 | 8.21 | 10.34 | 10.45 | 11.06 | 9.59 |

3.10 It can be seen that in the category of 200 MW/210 MW/250 MW series O&M expenses per MW of NTPC generating stations, in Rs. lakh/MW term are much higher than the state sector generating stations, namely Vijayawada TPS, Guru Gobind Singh TPS and Wanakbori TPS. During the open hearing, PSEB and GEB clarified that the data on O&M expenses furnished by them was only for generating stations and did not include headquarter expenses, like corporate expenses in case of NTPC generating stations, APGENCO has clarified during the open hearing that O&M expenses for Vijayawada TPS include headquarter expenses, but their staff expenses are under-stated in respect of pension. Further, water charges are very high in some of NTPC generating stations, like Vindhayachal STPS, Singrauli STPS, Rihand STPS and Ramagundam STPS, etc. In order to see the impact of corporate expenses and abnormal water charges, O&M expenses/MW have been worked out after excluding water charges and corporate expenses. O&M expenses/MW of NTPC generating stations are still high as compared to those for the state generating stations in this category.

3.11 O&M expenses per MW at the generating stations like Singrauli, Korba, Ramagundam and Farakka STPS of NTPC which have combination of 200 MW/210 MW and 500 MW sets are comparable to Chandrapur TPS of MSEB in Rs. lakh/MW terms in the same category. However, O&M expenses/MW in case of Farakka STPS as compared to Singrauli, Korba and Ramagundam STPS, which are old generating stations are clearly high. The lower operational level of Farakka STPS as compared to Singrauli, Ramandum and Korba STPS does not support higher O&M expenses of Farakka STPS. O&M expenses per MW in this category are much less than O&M expenses/MW in 200 MW/210 MW/250 MW series category of NTPC generating stations.

3.12 O&M expenses/MW of NTPC generating stations in 500 MW series category is less than O&M expenses in other two categories. These are also less than O&M expenses/MW of Trombay thermal power generating station having 2x500 MW sets. However, O&M expenses of Trombay generating station of Tata Power also includes O&M expenses of 350 MW combined cycle generating station and cannot be construed as representative number.

3.13 The performance of Vijayawada TPS of APGENCO and Wanakbori TPS of GEB is comparable to NTPC generating stations in 200 MW/210 MW/250 MW series category.

Considering this, O&M expenses of NTPC generating stations in this category appear to be high. On consideration of O&M expenses of 500 MW series like Rihand STPS and Talcher STPS and O&M expenses of Singrauli, Ramagundam, Korba and Farakka STPS also do not support O&M expenses of NTPC generating stations in this category.

3.14 It has been argued by some of the utilities that the vintage of the generating stations has an impact on O&M cost. The older the plant, higher would be O&M cost. However, the actual O&M data does not support that the older generating stations need more O&M as compared to new generating stations. The data is only suggestive of the fact that O&M expenses of 500 MW set generating stations are less than 210 set generating stations in per MW term. O&M cost data is also not suggestive of reduction in O&M expenses in per MW term with more number of units.

3.15 Based on the foregoing analysis, we are of the view that O&M expenses of the state generating stations can not be taken as representative numbers for the purpose of benchmarking. We, therefore, consider it appropriate to work out norm based on NTPC averages.

3.16 The Commission has passed tariff orders for tariff period 2001-04 in Singaruli, FGUTPP Stage-I, Vindhyachal STPS Stage-I, Korba STPS, Ramagundam STPS, Dadri GPS and has admitted normalised O&M expenses for 2000-01 based on average of actual O&M expenses for the period 1995-96 to 1999-2000 as per the current methodology. On the same lines, the normalised O&M expenses for 2000-01 have been worked out for remaining generating stations, namely Dadri (Thermal), Farakka STPS, Anta CCGT, Auraiya CCGT, Kawas and Gandhar GPS.

**Escalation in O&M expenses**

3.17 The existing escalation formula in the notification dated 26.03.2001 is as under:

The escalation of yearly expenses from the published data for the tariff period shall be computed as follows:

$0.4 \times INFL_{CPI} + 0.6 \times INFL_{WPIOM}$

where:

$INFL_{\mathbf{CPI}}$ **=** Annual Average Inflation in CPI_IW

$INFL_{\mathbf{WPIOM}}$ **=** Annual Average Inflation in WPIOM

Where as CPI_IW is directly published by the Government, WPIOM shall be computed from disaggregated data on wholesale prices published by Ministry of Industry.

**Note**

The special index of wholesale prices for power generating utilities (WPIOM) may be obtained as a weighted average of relevant components selected from disaggregated WPI series (1993-94=100) as given below:

| **COMMODITIES** | **WEIGHTS** |
|---|---|
| 1. Lubricants | 0.16367 |
| 2. Cotton Cloth | 0.90306 |
| 3. Jute, Hemp and Mesta Cloth | 0.37551 |
| 4. Paper & Paper Products | 2.04403 |
| 5. Rubber & Plastic Products | 2.38819 |
| 6. Basic Heavy Inorganic Chemical | 1.44608 |
| 7. Basic Heavy Organic Chemical | 0.45456 |
| 8. Paints Varnishes & Lacquers | 0.49576 |

| | |
|---|---|
| 9. Turpentine, Synthetic Resins, Plastic materials etc | 0.74628 |
| 10.Matches Explosives & Other Chemicals | 0.94010 |
| 11. Non-Metallic Mineral Products | 2.51591 |
| 12. Basic Metals Alloys & Metals Products | 8.34186 |
| 13. Machinery & Machine Tools | 8.36331 |
| 14. Transport Equipment & Parts | 4.29475 |
| **All the Above (WPIOM)** | **33.47307** |

$WPIOM = \frac{\sum_{i=1}^{14} wiWPIi}{\sum_{i=1}^{14} wi}$ where *WPIi* is the wholesale price index of the ith commodity and *wi* is the respective weight

3.18 We have not received any objective comments on the escalation formula. So we intend to continue its application. Based on the above escalation formula, the escalation for the past 5 years i..e. from 1998-99 to 2002-03 works out to 5.89%, 2.35%, 4.40%, 3.49% and 2.75% and the average escalation for the past 5 years works out to 3.78% (rounded off to 4%). Accordingly, we direct that an escalation rate of 4% shall be applied for working out O&M expenses for thermal power generating stations during the period 01.04.2001 to 31.03.2004 to arrive at normalised O&M expenses for the base year 2003-04 and to specify norms of O&M expenses for the tariff period 2004-2009.

3.19 Escalating base normalised O&M expenses for 2000-01 @ 4% average annual escalation rate, (Average escalation based on WPI & CPI indices for 1998-99 to 2002-03), the following O&M expenses have been worked out for 2001-02, 2002-03 and 2003-04, the actual O&M expenses for 2002-03 of NTPC generating stations are also given in the table below for comparison purposes:

## Table-3.2

| Sl No. | Name of the station/ Configuration | Year of Operation since COD of 1st Unit | Base O&M for 2000-01 | 2001-02 | 2002-03 | 2003-04 | Actual for 2002-03 |
|---|---|---|---|---|---|---|---|
| COAL BASED PLANTS | | | | | | | |
| 200 MW/210 MW/250 MW Series | | | | | | | |
| 1 | Dadri Thermal (NCTPS)/ (4x210 MW- 840 MW) | 9 | 9.81 | 10.20 | 10.61 | 11.03 | 13.26 |
| 2 | FGUTPS St- I/ (2 x 210 MW-420 MW) | 8 | 14.30 | 14.87 | 15.47 | 16.09 | 12.89 |
| 3 | Vindhyachal STPS St-I/(6x210 MW- 1260 MW) | 12.5 | 8.44 | 8.78 | 9.13 | 9.49 | 9.11 |
| 4 | Kahalgaon STPS/(4x210 MW- 840 MW) | 6 | 8.40 | 8.74 | 9.09 | 9.45 | 12.25 |
| 500 MW plants | | | | | | | |
| 1 | Rihand STPS/ (2x500 MW- 1000) | 11 | 9.29 | 9.66 | 10.05 | 10.45 | 10.43 |
| 2 | Talcher STPS/ (2x500 MW- 1000 MW) | 4 | 7.79 | 8.10 | 8.43 | 8.76 | 7.71 |
| Combination of 200 MW/210 MW/250 MW /500 MW Series | | | | | | | |
| 1 | Singrauli STPS/(5 x 200 MW+ 2 x 500 MW-2000 MW) | 19 | 7.87 | 8.19 | 8.51 | 8.85 | 8.24 |
| 2 | Korba STPS/(3x200 MW+3x500 MW- 2100 MW) | 18 | 7.11 | 7.39 | 7.69 | 7.99 | 8.27 |
| 3 | Ramagundam STPS/ (3x200 MW+3x500 MW-2100 MW) | 17 | 7.28 | 7.57 | 7.88 | 8.19 | 8.71 |
| 4 | Farakka STPS/ (3x200 MW+2x500 MW-1600) | 15 | 9.32 | 9.70 | 10.08 | 10.49 | 10.99 |
| | | | | | | | |
| | Weighted Average | 12 | 8.35 | 8.68 | 9.03 | 9.39 | 9.59 |

3.20 The Commission had considered base O&M expenses in 2000-01 after normalisation. This is after correcting the actual figures for abnormal increases on account of pay revision, arrears of pay, bulk purchase of material or expenditures not of recurring nature, break down maintenance cost not occurring in normal course, arrears of water charges, etc.

3.21 It is also seen that the normalised weighted average O&M expenses for 2003-04 at Rs.9.39 crore/MW rounded off to Rs. 9.50 Crore/MW works out about 2.75% of the cost of Rs.3457.32 Crore of Simadhari STPS (1000 MW) commissioned in January, 2003. This is quite reasonable on the consideration that average generating station life of 12 years of the existing generating stations. It is, therefore, desirable to consider normalised O&M expenses for prescribing O&M norm in Rs./MW term for all the existing as well new coal-based generating stations of NTPC. The weighted average O&M of Rs 9.50 Crore/MW is for generating stations having 200/210MW sets, 500 MW set generating stations and combination of 200/210MW sets and 500 MW set. Accordingly following base O&M norm shall be taken for 2003-04:

**Table- 3.3**

(Rs. Lakh/MW)

| 200/210/250 MW sets | 500 MW sets |
|---|---|
| **10.0** | **9.0** |

3.22 In case of the generating stations taken over by NTPC from the state utilities of 110 MW and below series, namely Tanda TPS (440 MW) and Talcher TPS (460 MW), the Commission has already allowed following O&M expenses for the base year 2000-01. It may be noted that the normalised O&M expenses in case of Tanda TPS are based on capital cost of Rs.607 Crs., whereas in the case of Talcher TPS, these are based on normalised actuals like other power stations.

**Table – 3.4**

| | | |
|---|---|---|
| Tanda TPS (4x110 MW) | Rs. 3720 Lakh | Rs. 8.45 Lakh/MW |
| Talcher TPS (4x60 MW+ 2x110MW) | Rs. 5557 Lakh | Rs. 12.08 Lakh/MW |

3.23 Escalating base O&M expenses for 2000-01 @ 4% average annual escalation rate, the following O&M expenses are worked out for 2003-04.

**Table – 3.5**

(Rs. Lakh/MW)

| Sl No. | Name of the station/ Configuration | Year of Operation since COD of 1st Unit | Base O&M for 2000-01 | 2001-02 | 2002-03 | 2003-04 |
|---|---|---|---|---|---|---|
| **A** | **110 MW and below Series** | | | | | |
| 1 | Tanda TPS (4x110 MW) | 16 | 8.45 | 8.79 | 9.14 | 9.51 |
| 2 | Talcher TPS (4x60 MW+ 2x110MW) | More than 25 years old | 12.08 | 12.56 | 13.06 | 13.58 |

## Gas-based/Liquid Fuel-based CCGT Generating Stations

3.24 In case of gas-based and liquid fuel-based generating stations of NTPC and NEEPCO, actual O&M expenses are as follows:

**Table – 3.6**

| Sl No. | **Name of the station/ Configuration** | **1995-96** | **1996-97** | **1997-98** | **1998-99** | **1999-00** | **2000-01** |
|---|---|---|---|---|---|---|---|
| | **NTPC** | | | | | | |
| 1 | **Anta GPS / (GTs: 3x88.71 MW+STs:1x153.2 MW- 419.33 MW))** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 1503 | 1493 | 1573 | 1957 | 2416 | 2503 |
| | O&M Expenses in Rs. Lakh/MW | 3.58 | 3.56 | 3.75 | 4.67 | 5.76 | 5.97 |
| 2 | **Auraiya GPS/ (GTs:4x111.19 MW+STs:2x109.3 MW- 663.36 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 1407 | 2215 | 1873 | 3676 | 3813 | 2853 |
| | O&M Expenses in Rs. Lakh/MW | 2.12 | 3.34 | 2.82 | 5.54 | 5.75 | 4.30 |
| 3 | **Kawas GPS/ (GTs-4x106 MW+STs-2x116.1 MW- 656.20 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 1686 | 1837 | 2861 | 3718 | 4352 | 5027 |
| | O&M Expenses in Rs. Lakh/MW | 2.57 | 2.80 | 4.36 | 5.67 | 6.63 | 7.66 |
| 4 | **Dadri GPS/ (GTs: 4x130.19 MW+STs: 2x154.51 MW- 829.84 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 1403 | 1735 | 2487 | 2798 | 4478 | 5439 |
| | O&M Expenses in Rs. Lakh/MW | 1.69 | 2.09 | 3.00 | 3.37 | 5.40 | 6.55 |
| 5 | **Gandhar GPS/ (GTs: 3x144.30 MW+STs: 1x224.49 MW- 657.39 MW)** | | | | | | |
| | O&M Expenses in Rs. Lakhs | 1277 | 1852 | 3129 | 2459 | 5115 | 2654 |
| | O&M Expenses in Rs. Lakh/MW | 1.94 | 2.82 | 4.76 | 3.74 | 7.78 | 4.04 |
| | **NEEPCO** | | | | | | |
| 1 | Assam CCGT (GTs: 6x33.5 MW + ST: 3x30 MW-291 MW) | | | | | | |
| | O&M Expenses in Rs. Lakhs | 608 | 681 | 983.15 | 1559 | 2632 | 2785 |
| | O&M Expenses in Rs. Lakh/MW | 3.63 | 3.39 | 3.76 | 5.35 | 9.04 | 9.57 |
| 2 | Agartala GT (GTs: 4x21 MW-84 MW) | | | | | | |
| | O&M Expenses in Rs. Lakhs | | | | 831 | 816 | 1110 |
| | O&M Expenses in Rs. Lakh/MW | | | | 9.90 | 9.71 | 13.21 |

3.25 It can be seen that O&M expenses are varying in the range of Rs.4.04 lakh/MW to Rs.7.66 lakh/MW for the above-noted five existing generating stations of NTPC. In this case also, actual O&M expenses are not suggestive of higher O&M expenses for older generating stations or lower O&M expenses for higher capacity generating stations. Thus, as in case of coal-based generating stations, here also it would be desirable to work out norm based on averages.

3.26 Following the methodology adopted in case of coal-based generating stations of NTPC, the base O&M cost for 2001-02, 2002-03 and 2003-04 works out as follows for the gas-based and liquid fuel-based CCGT generating stations of NTPC, the actual O&M expenses for 2002-03 of NTPC generating stations are also given below:

**Table 3.7**

| Sl No. | Name of the station/ Configuration | Year of Operation since the COD of 1st GT | Base O&M for 2000-01 | 2001-02 | 2002-03 | 2003-04 | Actual O&M expenses for 2002-03 |
|---|---|---|---|---|---|---|---|
| **GAS/LIQUID FUEL BASED PLANTS** | | | | | | | |
| 1 | Anta GPS / (GTs: 3x88.71 MW+STs:1x153.2 MW- 419.33 MW)) | 12 | 4.86 | 5.06 | 5.26 | 5.47 | 9.04 |
| 2 | Auraiya GPS/ (GTs:4x111.19 MW+STs:2x109.3 MW- 663.36 MW) | 10.5 | 3.69 | 3.84 | 3.99 | 4.15 | 6.08 |
| 3 | Kawas GPS/ (GTs-4x106 MW+STs-2x116.1 MW- 656.20 MW) | 9.75 | 5.19 | 5.40 | 5.61 | 5.84 | 8.8 |
| 4 | Dadri GPS/ (GTs: 4x130.19 MW+STs: 2x154.51 MW- 829.84 MW) | 8.75 | 3.97 | 4.13 | 4.30 | 4.47 | 5.93 |
| 5 | Gandhar GPS/ (GTs: 3x144.30 MW+STs: 1x224.49 MW- 657.39 MW) | 6 | 3.73 | 3.87 | 4.03 | 4.19 | 7.76 |
| | | | | | | | |
| | Weighted Average | 9.40 | 4.23 | 4.40 | 4.57 | 4.76 | 7.32 |

3.27 It can be seen that actual O&M expenses for 2002-03 are considerably higher than the normalised O&M expenses for 2002-03. NTPC has stated that during the period of supply of free warranty spares in NTPC gas-based generating stations, many mandatory spares were consumed which will not be available for future maintenance. NTPC also had long-term spares agreements under which the major spares were supplied at the price of mandatory spares cost with the nominal escalation. The current prices of spares for these generating stations are very high. NTPC has further stated that it has also approached GE-USA for providing the long-term service agreement for gas-based generating stations of GE make. The offer of the GE for repair and maintenance at the year 1999 prices indicates Rs.31.036 Crore for one combined cycle module. The total O&M cost with this data was found to be 6% of the current capital cost. NTPC has prayed that these aspects may be considered while deciding the norms for its generating stations.

3.28 This issue has been deliberated in detail during the hearings of tariff petitions of above NTPC generating stations and it was observed that supply of warranty spares free of cost for 10 years was one of the conditions at bidding stage and it is not possible to hold that the project cost of these generating stations does not include cost of these warranty spares. But to quantify the same was found difficult. Since NTPC is getting return corresponding to this additional capital expenditure of warranty spares and at the same time higher O&M cost corresponding to this, we are not inclined to include such spares in O&M expenses in future.

3.29 As such, as in case of the existing coal-based generating stations of NTPC, it is desirable to consider normalised O&M expenses for prescribing one norm in Rs./MW term for all the existing gas-based and liquid fuel-based CCGT generating stations of NTPC having provision of supply of warranty spares for 10 years free of cost. In case of the existing and new generating stations, which have no such provision of supply of warranty spares free of cost for 10 years may be allowed O&M expenses at Rs.7.5 lakh/MW which is about 2.5 % of project cost of Rs. 3.00 Cr/MW at present.

3.30 In case of NEEPCO's Assam CCGT generating station, there are abnormal increases in the year 1999-2000 and 2000-01 which are on account of abnormal increases in employees cost, security expenses, store consumed and are even higher than the NTPC generating stations. As regards Agartala GT, O&M expenses for 2000-01 are abnormally high as compared to those for the previous years, on account of abnormal increases in employees cost, security expenses, and corporate expenses allocation. The project cost of these two generating stations being relatively new generating stations is comparatively high as compared to NTPC generating stations in Rs./MW terms on account of location in difficult terrain and installation of small gas turbines of sizes below 50 MW. Their actual O&M expenses are not expected to be more than the normative @ 2.5% of project cost in the first year and then escalated as per the escalation rate based on weighted indices of WPI and CPI. Actual O&M expenses are lower than the norms in case of Assam CCGT. In case of Agartala GT, actual O&M expenses are higher than the normative in the year 2000-01. The normative and actual are working out as follows for the two gas-based generating stations of NEEPCO:

**Table 3.8**

| Name of Project | Project Cost in Rs. Cr. | 1998-99 | 1999-2000 | 2000-01 | 2001-02* | 2002-03* | 2003-04* |
|---|---|---|---|---|---|---|---|
| **Assam CCGT (291 MW)** | | | | | | | |
| Actual | 1451 | 5.35 | 9.04 | 9.57 | | | |
| Actual after Normalisation /Projected | | 5.35 | 6.42 | 7.70 | 8.01 | 8.33 | 8.66 |
| Normative @2.5% | | 12.47 | 13.20 | 13.64 | 14.19 | 14.75 | 15.34 |
| **Agartala GT (84 MW)** | | | | | | | |
| Actual | 309 | 9.95 | 9.71 | 13.21 | | | |
| Actual after Normalisation /Projected | | 9.95 | 9.71 | 11.65 | 12.12 | 12.60 | 13.10 |
| Normative @ 2.5% | | 9.20 | 9.74 | 10.06 | 10.46 | 10.88 | 11.32 |

*Projected O&M expenses based on normalised actual O&M expenses for 2000-01

3.31 It appears that O&M expenses for Agartala GT are high when compared with Assam CCGT generating station and need to be brought down. As such, NEEPCO should bring down O&M expenses of its Agartala generating station to 1.1 % of Assam CCGT generating station's actual O&M expenses of Rs. 8.66 lakh/MW after normalisation. This takes into consideration the fact that size of Agartala gas turbines is about 90% of Assam gas turbines. Thus, for small gas turbine generating stations having gas turbines of capacity 50 MW and below, an average of Rs. 9.10 lakh/MW ((8.66+8.66x1.1)/2 = 9.10) should be allowed for the year 2003-04.

3.32 Based on the discussion in the paragraphs above, the following base O&M cost norms for the year 2003-04 shall be adopted:

**Table 3.9**

| | |
|---|---|
| Coal/lignite based Plants of NTPC/NLC | |
| 210/210/250 MW set Stations | Rs. 10.00 Lakh/MW |
| 500 MW set Stations | Rs. 9.00 Lakh/MW |
| Tanda TPS (440 MW) | Rs. 9.50 Lakh/MW |
| Talcher TPS (460 MW) | Rs.13.58 lakh/MW |
| **Gas/Liquid fuel based Plants other than Small Gas Turbine Power Plants** | |
| Stations having provision of supply of Warrantee spares for 10 years free of cost | Rs. 5.00 Lakh/MW |
| Stations having no provision of supply of Warranty spares for 10 years free of cost | Rs. 7.50 Lakh/MW |
| **Small Gas Turbine Power Plants** | Rs. 9.10 Lakh/MW |

3.33 The above base O&M cost norms shall be escalated at an annual average escalation rate of 4% per annum for the period 2004-09 as per weighted WPI/CPI indices in the ratio of 60:40 as per the Commission's methodology.

3.34 In view of the above analysis, the Operation and Maintenance expenses including insurance for the existing as well as new generating stations of NTPC and NLC shall be taken as follows:

(a) Coal-based/Lignite-based Stations (Existing as well as New)

**Table 3.10**

(Rs. lakh/MW)

| Year | 200/210/250 MW sets | 500 MW sets | Tanda TPS | Talcher TPS |
|---|---|---|---|---|
| 2004-05 | 10.40 | 9.36 | 9.88 | 14.12 |
| 2005-06 | 10.82 | 9.73 | 10.28 | 14.69 |
| 2006-07 | 11.25 | 10.12 | 10.69 | 15.28 |
| 2007-08 | 11.70 | 10.52 | 11.11 | 15.89 |
| 2008-09 | 12.17 | 10.95 | 11.56 | 16.52 |

**Note:** For the generating stations having combination of 200/210/250 MW sets and 500 MW set, a weighted average value shall be the O&M norm.

(b) Gas-based/Liquid Fuel-Based Generating Stations:

**Table 3.11**

(Rs. lakh/MW)

| Year | Gas /Liquid fuel based power Stations other than Small Gas Turbine Power Stations | | Small Gas Turbine Power Stations |
|---|---|---|---|
| | With Warrantee Spares of 10 years | Without any Warrantee Spares | Without any Warrantee Spares |
| 2004-05 | 5.20 | 7.80 | 9.46 |
| 2005-06 | 5.41 | 8.11 | 9.84 |
| 2006-07 | 5.62 | 8.44 | 10.24 |
| 2007-08 | 5.85 | 8.77 | 10.65 |
| 2008-09 | 6.08 | 9.12 | 11.07 |

3.35 However, in case of abnormal O&M expenses arising due to circumstances beyond the control of generating company, the generating company has the liberty to approach the Commission for allowing such abnormal expenses on merits of each case.

## HYDRO POWER GENERATING STATIONS

### Existing Provisions

3.36 In accordance with the terms and conditions of tariff presently in force, the operation and maintenance expenses of hydro power generating stations in operation for more than five years as on 1.4.2001 are regulated based on actual O&M expenses incurred for these generating stations for the years 1995-1996 to 1999-2000. The actual O&M expenses for these five years are normalized and the average expenses after normalization form the base O&M expenses for the year 1997-1998 which are further escalated at the rate of 10% per annum up to the year 1999-2000 and thereafter at the rate of 6% per annum to arrive at the normative O&M expenses for the respective year during the tariff period. For the generating stations in operation for less than five years on 1.4.2001, the base O&M charges are fixed at 1.5% of the capital cost in the first year of operation, with 10% annual escalation in subsequent years up to 1999-2000. The rate of escalation is taken as 6% to arrive at the base figure for the year 2000-01. During the tariff period, O&M expenses for respective year are computed by applying the escalation factor of 6% over O&M expenses for the previous year. A deviation of escalation factor computed for actual data that lies within 20% of the notified escalation factor (which works out to 1.2% on either side of 6%) is to be absorbed by the generating company. The deviations beyond this limit are to be adjusted on the basis of actual escalation factor for which the utility concerned is to approach the Commission separately.

**Actual Vs Normative O&M Expenses**

3.37 Like thermal power generating stations, the Discussion Paper had debated whether it would be advisable to move away from "actual" to "normative" O&M expenses. The Discussion Paper flags two options for the normative O&M expenses:

(a) As a percentage of capital cost, and
(b) As benchmark cost in Rs./ MW.

3.38 The views of the stakeholders are summarised below:

(a) DVC has suggested that O&M cost should be expressed as Rs. Per MW and should initially be pegged at 2.5% of the normative capital cost (for new the generating stations) with appropriate escalation as per the existing norms of the Commission;

(b) NEEPCO has supported the view of fixing of normative O&M cost on basis of percentage of current capital cost and with annual escalation @ 10%;

(c) NHPC has suggested that the present method of working out the O&M cost i.e. normative for new projects and average expenses duly escalated for the old projects is reasonable and the normative O&M expenses as stated in the Discussion Paper are not reasonable because the hydro generating stations are tailor-made and any two generating stations of same capacity are not identical as far as O&M expenses are concerned. Also, O&M expenses depend upon the location of the dam, weir, powerhouse, employees' colonies, remoteness of the projects, silt content in the water. NHPC has proposed O&M expenses for new projects @ 2.5% of the capital cost and escalation @ 10% for the old generating stations;

(d) WBSEB has suggested O&M expenses @ 1.5% of the capital cost or actual whichever is lower and escalated @ 6% as per the Commission's notification. It should exclude abnormal expenses;

(e) Maharashtra SEB has stated that O&M charges may be recovered on the basis of actual as prescribed by the Commission for the current tariff period;

(f) APTRANSCO has stated that option B of the discussion paper may be considered. However, bench mark values have to be arrived at based on the best operating generating stations;

(g) Kerala State Electricity Board has stated that benchmark Per MW have to be specified based on the best operating generating stations for ROR, ROR with pondage and storage type generating stations. A reasonable weightage should be given based on installed capacity, unit size, no of units, length of water conductor system etc;

(h) Assam State Electricity Board has stated that benchmarking of O&M expenses on per unit basis with reference to a base year is acceptable;

(i) Karnataka Power Corporation Limited has stated that the concept of adopting a bench mark cost per MW based on the unit size is acceptable as the same would provide a level playing field;

(j) H.P. Electricity Regulatory Commission has stated that Benchmark cost per MW is definitely a better option. This would however, require details of the expenses that are necessary for the efficient operation of the generating station. Factors such as life of machines / equipment, renovation & modernization, technology used, extent of automation etc. would have to be given due weightage while fixing the benchmarks;

(k) M.P. Electricity Regulatory Commission has stated that O&M expenses should be allowed on normative basis @ 1.5%. Normative may be further modified by assessing actual O&M expenses of previous 5 year old generating stations and first five years of a new generating station;

(l) Rajasthan Electricity Regulatory Commission has suggested that for the existing generating stations, Commission should benchmark the base for O&M expenses on the basis of historical cost. For subsequent years, O&M

expenses may be arrived at by escalating O&M expenses as per indices to be decided by the Commission. For new generating stations, O&M expenses may be computed as 1.5% of GFA;

(m) Karnataka Electricity Regulatory Commission has stated that there was need to set a normative level of expenditure that could be allowed to the generating companies by benchmarking the expenses with reference to the best operating generating stations and size of the units. Any additional O&M expenses considering the local conditions could be examined by the Commissions separately;

(n) Andhra Pradesh Electricity Regulatory Commission has suggested that O&M expenses being computed based on macro numbers like Rs Cr Per MW etc would not provide a true reflection of the project cost and instead might involve many assumptions like separate numbers for type of hydro generating stations etc;

(o) Orissa Electricity Regulatory Commission has submitted that O&M expenses should be calculated @ 2.5% on the actual capital cost instead of current capital cost. The escalation to be provided retrospectively @ 10% as per GOI norms up to the year 2000-01 and further @ 6% as per the Commission's notification dated 26.3.2001;

(p) Kerala State Electricity Regulatory Commission has stated that O&M expenses could be allowed on normative basis and arrived at the cost per MW;

(q) Tamil Nadu Electricity Regulatory Commission has stated that the option 'B' regarding benchmarking of O&M expenses should be considered for adoption. The bench mark value might be based on actuals of the best run generating station in the most efficient region, with due weightage to location, size of the generating station etc;

(r) Punjab State Electricity Board has stated that Option B of Discussion Paper seems to be more reasonable . They have further suggested that bench mark cost per MW should be based on actual O&M expenses for the best operating generating station with a reasonable weightage to the size, age and technology of the generating stations;

(s) Rajasthan Vidyut Prasaran Nigam Ltd. has stated that Bench mark cost per MW (for typical efficient installation) appears to be a reasonable option. 10% allowance may be provided on such mark values;

(t) Bihar State Electricity Board submitted that for new hydro power generating stations, it should be 1.5% of the capital cost or actual O&M expenses which ever was less might be adopted and this should be escalated at the rate of 4% per annum. For the existing generating stations, the normative or actual O&M expenses of base year 2003-2004 which ever was less should be considered as O&M expenses with escalation at the rate of 4%;

(u) Shri K.P. Rao has stated that O&M expenses might be reckoned @ 1.5% of capital cost of hydro power generating stations. These should be taken with "Current Capital Costs" and not on the original cost; and

(v) Malana power company has suggested that O&M cost should be taken @ 2.5% of the normative capital cost/ MW in case of run-of-river hydro power stations and the normative cost can be taken as Rs .5 crore/ MW.

From the above, we have observed that West Bengal State Electricity Board, Madhya Pradesh Electricity Regulatory Commission, Rajasthan Electricity Regulatory Commission, Orissa Electricity Regulatory Commission and Sh. K.P. Rao Ex-Member CEA have suggested O&M expenses ranging from 1.5 to 2.5% on the capital cost.

**Choice of Methodology for O&M Expenses**

3.39 From the above, it can be seen that like thermal power generating stations, for hydro power generating stations also normative O&M expenses have been preferred over actual O&M expenses by majority of the stakeholders. The Commission's preference of normative O&M cost over actual O&M expenses has already been discussed in para 3.4 above in regard to thermal power stations. In case of hydro power generating stations also, the normative O&M costs could be determined either as percentage of Capital Cost or on the basis of Rs./MW, as has been discussed in Para 3.38 above.

3.40 We have observed from the comments received and presentations made at the open hearing that some of the stakeholders have suggested O&M expenses @ 1.5 % to 2.5 % of the capital cost. Malana power company has suggested that O&M cost should be taken @ 2.5% of the normative capital cost/MW in case of run-of-river hydro power generating stations. The normative capital cost itself has been suggested by them at Rs 5.5 crore/MW. Since in the case of hydro power generating stations, the capital cost may vary from generating stations of one type to another i.e. purely run-of-river, pondage and storage type, it may be difficult to arrive at a normative capital cost common to all types of generating stations. Hence suggestion to allow O&M expenses at normative capital cost may not be feasible.

3.41 In addition to above and apart from the reasons discussed in para 3.7, O&M expenses based on capital cost in hydro power generating stations have an added dimension. It is well recognized that the cost of hydro projects of equal capacity may vary considerably from site to site depending upon the nature and extent of civil works, geological surprises etc. Therefore, project cost based on norms will not be an ideal route. It is proper to assume that for a similar (in terms of MW output) hydro power generating station, O&M expenses will be of the same magnitude irrespective of its capital cost. In view of this, we are of the opinion that it is more appropriate to apply O&M cost norms in terms of Rs./MW for both the existing and new hydro generating stations.

**Benchmarking cost norms in terms of Rs/ MW of the installed capacity**

3.42 For the purpose of benchmarking O&M cost on the basis of Rs. / MW, the Commission sought O&M cost of various types of hydro power generating stations viz. storage, run-of –river with and without pondage across the country for the years 1995-96 to 2001-02. Apart from the central sector utilities viz. National Hydro Power Corporation and North Eastern Electric Power Co., state utilities of Bhakra Beas

Management Board, Punjab State Electricity Board, Himachal Pradesh State Electricity Board, Gujarat State Electricity Board, Madhya Pradesh Electricity Board, Orissa Hydro Power Corporation, Andhra Pradesh Generation Corporation, Karnataka Power Corporation Ltd, Kerala State Electricity Board, Tamil Nadu Electricity Board, Uttaranchal Jal Vidyut Nigam and Tatas have also furnished information to the Commission for carrying out study of O&M cost.

3.43 Out of the 48 hydro power generating stations of various utilities across the country for which O&M expenses data has been received, 36 stations are storage type generating stations and the remaining 12 are run-of-river/pondage type generating stations.

**Analysis of O&M cost data**

3.44 O&M expenses have been considered in respect of the following components of the hydro power generating station:

(a) Repair & Maintenance;
(b) Consumption of stores and spares;
(c) Employees cost;
(d) Insurance expenses;
(e) Security expenses;
(f) Administrative & Misc. expenses;
(g) Corporate office expenses allocated to the generating station; and
(h) Proportionate O&M expenses of irrigation works considered to be appurtenant works of the generating station.

**Methodology Adopted for Analysis**

3.45 The state utilities have furnished O&M expenses data for a period of seven years starting from 1995-96. O&M expenses of most of the utilities have shown an increasing trend during the years 1997-98 and 1998-99 because of hike in salaries and perks of the employees due to revision of pay scales and also payment of arrears. To avoid the impact of this sudden increase in O&M expenses, analysis of O&M cost has been made from the data for the years 1999-00, 2000-01 and 2001-02. Average O&M expenses/MW of each hydro power generating station for these three years have been computed. Average of O&M/MW for the years 1999-2000, 2000-01 and 2001-02 considered as O&M expenses for the mid year 2000-01 have been escalated @ 4% per annum to arrive at O&M cost in Rs./ MW for the base year 2003-04, for the next tariff period.

**Escalation in O&M expenses**

3.46 The existing escalation formula in the Notificaion dated 26.03.2001 is as under:

The escalation of yearly expenses from published data for the tariff period shall be as below:

Escalation = 0.55 X $Infl_{CPI}$ + 0.45 X $Infl_{WPIOM}$
Where

$Infl_{CPI}$ = Annual Average Inflation in CPI _IW

$Infl_{WPIOM}$ = Annual Average Inflation in WPIOM

Note 1

Where as CPI _IW is directly published by the Government, WPIOM shall be computed from disaggregated data on wholesale prices published by Ministry of Industry.

Note 2

WPIOM may be obtained as a weighted average of relevant components selected from disaggregated WPI series (1993-94=100) as given below:

| COMMODITIES | WEIGHT |
|---|---|
| 1. Lubricants | 0.16367 |
| 2. Cotton Cloth | 0.90306 |
| 3. Jute, Hemp and Mesta Cloth | 0.37551 |
| 4. Paper & Paper Products | 2.04403 |
| 5. Rubber & Plastic Products | 2.38819 |
| 6. Basic Heavy Inorganic Chemical | 1.44608 |
| 7. Basic Heavy Organic Chemical | 0.45456 |
| 8. Paints Varnishes & Lacquers | 0.49576 |
| 9. Turpentine, Synthetic Resins, Plastic materials etc | 0.74628 |
| 10.Matches Explosives & Other Chemicals | 0.94010 |
| 11. Non-Metallic Mineral Products | 2.51591 |
| 12. Basic Metals Alloys & Metals Products | 8.34186 |
| 13. Machinery & Machine Tools | 8.36331 |
| 14. Transport Equipment & Parts | 4.29475 |
| All the Above (WPIOM) | 33.47307 |

$WPIOM = \frac{\sum_{i=1}^{14} wiWPIi}{\sum_{i=1}^{14} wi}$ where *WPIi* is the wholesale price index of the ith commodity and *wi* is the respective weight

3.47 We have not received any suggestions/comments on the escalation formula so we intend to continue with the same. Based on the above escalation formula, the escalation for the past 5 years i.e. from 1998-99 to 2002-03 works out to 7.69%, 2.61%, 4.24%, 3.68% and 3.09% and the average escalation for these years works out to 4.26% (rounded off to 4%). Accordingly, this escalation rate of 4% has been applied for working out O&M expenses for hydro generating stations during the period 01.04.2001 to 31.03.2004 to arrive at normalised O&M expenses for the base year 2003-04.

3.48 Station-wise O&M expenses /MW of the station capacity for run-of-river (ROR) and ROR with pondage type generating stations and for the storage based generating stations have been computed. The results of the computation are summarized below:

**Run-of-River(ROR) and ROR with Pondage type generating stations**

**Table- 3.12**

| HE Project | Installed Capacity (MW) | Years of operation | O&M expenses/MW in 2003-04 (Rs. lakh) |
|---|---|---|---|
| 1. Dehar, BBMB | 990 | 25 | 7.2 |
| 2. Ganguwal & Kotla, BBMB | 168 | 40 | 5.2 |
| 3.Anandpur Sahib, PSEB | 134 | 17 | 6.5 |
| 4. Shanan, PSEB | 110 | 36 | 9.2 |
| 5. UBDC, PSEB | 60 | 13 | 5.7 |
| 6. Bhaba, HPSEB | 120 | 13 | 3.5 |
| 7. Bassi, HPSEB | 60 | 32 | 7.6 |
| 8. Giri Bata, HPSEB | 60 | 25 | 8.0 |
| 9. Salal, NHPC | 690 | 15 | 10.2 |
| 10.Chamera, NHPC | 540 | 8 | 11.7 |
| 11. Tanakpur | 94.2 | 9 | 21.2 |
| 12.Baira Siul | 198 | 20 | 16.0 |
| Average | | | 8.6 |

**Storage type generating stations**

**Table- 3.13**

| HE Project | Ins. Capacity (MW) | Years of operation | O&M expenses /MW in 2003-04 (Rs. lakh) |
|---|---|---|---|
| Northern Region | | | |
| 1. Bhakra, BBMB | 1325 | 42 | 3.1 |
| 2. Pong, BBMB | 390 | 24 | 3.2 |
| 3.Mukerian, PSEB | 207 | 19 | 5.9 |
| Western Region | | | |
| 4. Ukai, Gujarat | 305 | 28 | 2.7 |
| 5. Gandhi sagar, MP | 115 | 42 | 1.5 |
| 6. Bargi, MP | 90 | 14 | 2.1 |
| 7. Pench, MP | 160 | 15 | 1.3 |
| 8. Ban Sagar Tons, MP | 315 | 11 | 3.1 |
| 9. Bhira, Tatas | 300 | 76 | 6.3 |

| | | | |
|---|---|---|---|
| 10. Bhivpuri, Tatas | 144 | 71 | 9.8 |
| 11. Khopoli, Tatas | 144 | 72 | 7.8 |
| Eastern Region | | | |
| 12. Balimela, Orissa | 360 | 29 | 4.7 |
| 13. Upper Kolab, Orissa | 320 | 14 | 2.4 |
| 14. Hirakud-I, Orissa | 331.5 | 46 | 5.7 |
| 15. Rengali, Orissa | 250 | 17 | 5.8 |
| Southern Region | | | |
| 16. Lower Sileru, AP | 460 | 26 | 1.5 |
| 17. Srisailam, AP | 770 | 20 | 1.1 |
| 18. Nagarjunasagar, AP | 815.6 | 22 | 1.4 |
| 19. Machkund, AP | 120 | 47 | 3.9 |
| 20. Idukki, Kerala | 780 | 27 | 1.1 |
| 21. sabarigiri, Kerala | 300 | 37 | 1.8 |
| 22.Sharavathy & Lingna-makki, Karnataka | 1090 | 38 | 4.6 |
| 23. Nagjhari & Supa Dam PH, Karnataka | 855 | 23 | 4.6 |
| 24. Varahi, Karnataka | 239 | 14 | 13.8 |
| 25. Periyar, Tamil Nadu | 140 | 50 | 4.7 |
| 26. Pykara, TN | 70.2 | 67 | 6.9 |
| 27. Kundah PH-1, TN | 60 | 42 | 6.5 |
| 28. Kundah, PH-2, TN | 175 | 42 | 2.6 |
| 29. Kundah, PH-3, TN | 180 | 37 | 2.3 |
| 30. Kadamparai, PSS, TN | 400 | 15 | 1.8 |
| 31. Sholayar, TN | 40 | 65 | 1.9 |
| 32. Mettur Tunnel PH, TN | 200 | 37 | 3.6 |
| 33. Mettur Dam PH, TN | 40 | 65 | 10.1 |
| N.E. Region | | | |
| 34. Loktak, NHPC | 105 | 19 | 29.2 |
| 35. Kopili, NEEPCO | 200 | 14 | 13.2 |
| 36. Khandong, NEEPCO | 50 | 18 | 13.2 |
| Average | | | 5.9 |

3.49 Based on the result of the studies made, we have observed that –

(a) In case of run-of-river and pondage type of generating stations, O&M expenses of NHPC generating stations viz. Salal (Rs. 10.2 lakh/MW), Chamera (Rs 11.7 lakh/MW), Baira Siul (Rs 16 lakh /MW) and for Tanakpur HEP (Rs. 21.2 lakh /MW) are higher compared to O&M of Dehar (Rs 7.2 lakh/MW) of BBMB, Bassi (Rs 7.6 lakh/MW) and Giri Bata (RS 8 lakh/MW) of HPSEB. Average O&M expenses/ MW of 12 generating stations has been worked out to be Rs. 8.6 lakh/MW.

(b) In case of storage-based hydro power generating stations, O&M expenses of Loktak HEP of NHPC at Rs 29.2 lakh/MW are the highest of all 36 storage-based generating stations for which studies have been made, followed by Varahi of KPCL at Rs. 13.8 lakh/MW, Kopili and Khandong of NEEPCO at Rs 13.2 lakh/MW. Average O&M expenses of 36 storage type generating stations work out at Rs. 5.9 lakh/MW.

3.50 It is also observed that one of the reasons for higher O&M expenses of NHPC generating stations compared to generating stations of the other utilities is the inclusion of 'insurance component'. In most of the hydro power generating stations of other utilities, either no component of insurance expenses has been provided or wherever insurance coverage is there, it is very less. It is understood that insurance expenses have been provided due to corporate policy of insurance coverage to all fixed assets of the project, that is, generating station machinery, civil and hydro-mechanical works and also of the employees located in remote areas of some of the generating stations. Insurance expenditure incurred in respect of NHPC and NEEPCO hydro power generating stations during the year 2001-02 are stated as under:

| Hydro station | Insurance amount (Rs. Crore) |
|---|---|
| NHPC /NEEPCO generating stations | |
| 1. Chamera | 10.60 |
| 2. Salal | 4.77 |
| 3. Tanakpur | 1.97 |
| 4. Baira Siul | 0.93 |
| 5. Loktak | 0.85 |
| 6. Kopili | 0.51 |

3.51 Thus, the insurance cost amongst other things is responsible for higher O&M cost in the Central Sector hydro stations as compared to State Sector hydro stations. However, the following factors also enhance the O&M expenses of the hydro power generating stations of the Central Sector:

(i) BBMB in their written submission and presentation made at the hearing on the O&M expenses of hydro power generating stations have stated that while working out the O&M expenses of their hydro power generating stations they have included the proportionate O&M expenses of irrigation works considered to be appurtenant works of a power generating station viz. water regulation, maintenance of hydel channel, maintenance of common facilities etc. It is our apprehension that in case of storage type hydro power generating stations of SEBs/TRANSCOs/ GENCOs which have both irrigation and power components, the proportionate O&M expenses of irrigation works considered to be appurtenant works of a power generating station might not have been included in the total O&M expenses; and

(ii) We are of the view that O&M expenses of the SEBs/TRANSCOs/ GENCOs and other utilities generating stations (except BBMB, KPCL and Tata's owned generating stations) may not have included proportionate corporate expenses charged to their generating stations.

This would be judged from the fact that O&M expenses of some of the generating stations appear to be very low e.g. Gandhi Sagar (Rs 1.51 lakh/MW), Pench (Rs 1.34 lakh/MW), Ukai(Rs 2.74 lakh/MW), Upper Kolab (Rs 2.42 lakh/MW), and also of Bargi, Ban sagar Tons, Lower Sileru, Srisailam, Nagarjuna sagar, Idukki, Sabrigiri, Kundah PHs, Sholayar, Kadamparai PSS etc. which have O&M expenses varying from Rs 1.14 lakh /MW to Rs. 3.12 lakh /MW. Also, in case of hydro power generating stations of Uttaranchal Jal Vidyut Nigam, actual O&M expenses during the year 2002-03 vary from Rs. 17 lakh/ MW to Rs 24 lakh/MW because they have loaded whole of the expenses towards maintenance by irrigation department to O&M expenses of the generating station.

3.52 We, therefore, do not consider it appropriate to benchmark O&M expenses on the basis of average O&M expenses of state utilities generating stations. It, therefore, leaves with only one choice that benchmarking be done on the basis of O&M expenses of NHPC/NEEPCO stations.

3.53 The Commission has, in the recent past, issued orders on tariff for various stations of NHPC for the period 2001-04. These tariff orders contain O&M expenses, which have been allowed after prudence check. In the case of NEEPCO though the orders for Kopili

& Khandong hydroelectric stations have not been issued, yet their petitions have been received and after preliminary prudence check, the numbers arrived at have been used for the present study purposes. However, these numbers have no bearing on the final determination of O&M expenses in the petitions presently pending. Further, an escalation factor of 4% has been used during the years 2001-02 and 2002-03 to arrive at the numbers for the base year 2003-04. This is on account of the fact that actual inflation in WPI & CPI yields an average escalation factor of 4%. The results obtained are tabulated below:

**O&M expenses in Rs./ MW**

**Table- 3.14**

(Rs lakh/MW)

| Station | O&M expenses / MW | | | Avg. | O&M in Base Year |
|---|---|---|---|---|---|
| | 1999 -00 | 2000-01 | 2001-02 | 1999-00 to 2001-02 | 2003-04 |
| Salal | 7.0 | 7.4 | 7.9 | 7.4 | 8.3 |
| Chamera | 9.7 | 10.3 | 10.9 | 10.3 | 11.6 |
| Baira Siul | 10.1 | 10.7 | 11.3 | 10.7 | 12.0 |
| Kopili | 10.4 | 11.77 | 13.08 | 11.75 | 13.22 |
| Khandong | 10.4 | 11.77 | 13.08 | 11.75 | 13.22 |
| Tanakpur | 16.2 | 17.2 | 18.2 | 17.2 | 19.3 |
| Loktak | 18.2 | 19.3 | 20.4 | 19.3 | 21.7 |
| Overall Wt. Avg | | | | | 11.6 |
| Wt. Average without Loktak & Tanakpur | | | | | 10.5 |

Note:

(1) Tanakpur and Loktak generating stations have not been considered in the weighted average because their O&M expenses are very high compared to those of other central sector hydro power generating stations.
(2) Escalation considered @ 4% per annum

3.54 From the above, it would be seen that the overall weighted average O&M expenses in Rs./MW works out to Rs. 11.6 lakh/MW. However, O&M expenses in the case of Loktak and Tanakpur generating stations are abnormally high and, therefore, could be ignored. Keeping this in view, the weighted average works out to be Rs. 10.5 laks/MW. We adopt this as the norm (in the base year 2003-04) for O&M expenses. This will be further escalated at a rate of 4% per annum for arriving at the norms for the five years of the tariff period 2004-09. As has been stated earlier, the escalation rate of 4% per annum has been computed on the basis of actual inflation rate in CPI & WPI.

3.55 In view of the above analysis, the normative Operation and Maintenance expenses including insurance applicable for the existing as well as new hydro power generating stations shall be taken as follows :

**Table- 3.15**

(Rs. lakh/MW)

| Year | O& M Expenses |
|---|---|
| 2004-05 | 10.92 |
| 2005-06 | 11.36 |
| 2006-07 | 11.81 |
| 2007-08 | 12.28 |
| 2008-09 | 12.77 |

3.56 It may be noted that in arriving at the norms for O&M expenses, the Commission has ignored O&M expenses at Loktak and Tanakpur generating stations as these are abnormally high. This abnormality needs to be taken care of after prudence check. We, therefore, direct that in case of abnormal O&M expenses on account of abnormal siltation, abnormal security and abnormal land slides, the hydro power generating utility has the liberty to approach the Commission for allowing such abnormal expenses on merits of each case.

## INTER-STATE TRANSMISSION

### Existing Provisions

3.57 As per the terms and conditions of tariff dated 26.03.2001, the operation and maintenance expenses of inter-state transmission system are regulated based on normative O&M expenses per Ckt-Km. of line-length and per bay for a Region. The existing notification dated 26.3.2001 has laid down methodology for calculation of normative O&M . If the actual O&M expenses of sub-stations and lines for the years 1995-1996 to 1999-2000 were separately available for each region, these should be normalised by dividing them by line-length and number of bays in each region. The average of such normalised O&M expenses per Ckt-Km. of line-length and per bay for the last five years would then be used to derive the base O&M for lines and sub-stations. Where the data was not available, the Commission also prescribed a proxy method of apportioning O&M expenses in the region to the sub-stations and lines on the basis of 30:70 ratio for normalisation purposes. The five years average of normalised O&M expenses was to be escalated @ 10% per annum to reach the base O&M value for the year 1999-2000. The escalation factor beyond 1999-2000 was 6% per annum. A deviation of the escalation factor computed from the actual data that lies within 20% of the above notified escalation factor (which works out to 1.2% on either side of 6%) shall be absorbed by the utility. Deviations beyond this limit would be adjusted on the basis of actual escalation factor for which the utility is to approach the Commission separately. In order to calculate the permissible O&M expenses for particular system the normative values of O&M i.e. Normative O&M per Ckt-Km and per bay shall have to multiplied by the line length and number of bays in a given system. The transmission utility should present its application for determination of tariff with full details of year-wise actual O&M cost after excluding abnormal expenditure. The break up of actual O&M expenses was sought in the following heads:

(a) Employees Cost;
(b) Repair and Maintenance;
(c) Power Charges;
(d) Training and Recruitment;
(e) Communication Expenses;
(f) Travelling Expenses;
(g) Printing and Stationery;
(h) Rent;
(i) Miscellaneous Expenses/ Others;
(j) Insurance; and
(k) Corporate office expenses allocation.

3.58 Prior to the Commission's notification dated 26.3.2001 for the tariff period 1.4.2001 to 31.3.2004, O&M expenses were governed by Ministry of Power notification dated 16.12.97. The Ministry of Power notification provided for the operational and maintenance expenses including expenses on insurance, if any, for the further full year after commissioning of the transmission system @ 1.5% of actual expenditure for plain and 2% for the hilly area. The expenditure on O&M in each subsequent year was to be escalated as per weighted price index taking into account 60 percent weightage of whole price index and 40 percent weightage of consumers price index.

**Proposal in the Discussion Paper**

3.59 In the Discussion Paper it was suggested that instead of allowing region-wise normative O&M expenses based on actuals as per the existing notification, either average normative O&M expenses of all the regions or normative O&M expenses of the most efficient region may be adopted as the norm on all-India basis. It was also stated that as use of average of all the regions will not induce efficiency, O&M expenses of most efficient region may be a better option to benchmark O&M values.

**Views of stakeholders**

3.60 Comments/suggestions from the stakeholders, that is , the regulated entities, beneficiaries/State transmission utilities, financial institutions and IPPs are as under:

(a) Ministry of Power has suggested that O&M cost should be fixed on normative basis with the cost of actual manpower as provided in the DPR as the base cost to be escalated subsequently according to CPI.

(b) DVC has supported the existing stipulation subject to yearly review. MSEB has suggested continuation of the existing methodology. It has argued against average normative O&M expenses for all the regions to be adopted as norms as this would be unfair. UPPCL has also suggested continuation of existing method with modification that if year-on-year increase in the previous 5 years data is more than the weighted average of WPI OM and CPI IW for the respective year, then this increase should be justified with reasons. It has also suggested that the Commission may apply principle of prudence to determine acceptable O&M cost for every year. GEB has opposed fixation of norms on per bay or per km basis. According to GEB, actual cost has to be claimed based on certificate of independent auditor.

(c) TNEB has stated that allowing O&M expenses based on actuals is not a prudent method and has suggested adoption of 1.5% of the capital cost on normative basis as O&M expenses both for plain and hilly terrain. WBSEB has suggested O&M expenses @ 1.5% of capital cost with 6% escalation or as per Commission's Notification dated 26.3.2001 whichever is lower.

(d) RVPNL has supported fixation of normative O&M expenses on per bay/km basis for typical efficient installation. PSEB has supported benchmark cost per bay/km basis subject to condition that O&M expenses arrived at by using this benchmark should not exceed 1.5% to 2.0% of the capital cost. According to HPERC, benchmarking of cost on per bay or per km basis is a better option as O&M expenses are not generally linearly related to the project cost. GERC has stated that benchmarking of O&M cost should be done with reference to better performing system and the utility concerned should be allowed to retain the earnings from better than normative performance. KSERC has suggested that the benchmarking of O&M cost should be done based on actual O&M expenses in the past. It has further stated that these expenses might be subject to periodic revision based on realistic cost escalation rather than allowing a percentage increase annually. TNERC and MPSEB have opined that fixing O&M expenses as percentage of capital cost may lead to over-capitalisation and has suggested benchmarking on per bay or per km basis. They have further suggested that benchmark value might be based on actuals of the most efficient region with due weightage for factor such as size, location, etc. RERC has suggested that O&M expenses on per km or per bay basis or alternatively in the ratio of 30:70 for sub-stations and lines including insurance charges. Bharat Chamber of Commerce has expressed its agreement with the suggestion in the Discussion Paper that benchmarking on per km or bay basis should be done on the basis of most efficient region. Utkal Chamber of Commerce & Industry and Bengal National Chamber of Commerce & Industry have also suggested benchmarking of O&M expenses on per bay/km basis.

(e) GRIDCO has suggested to move away from actual O&M expenses to normative O&M expenses as on the following grounds:

- (i) actual O&M expenses include expenses for power consumed in the residential colonies, construction power etc;
- (ii) their scope for booking capital expenditure as revenue expenditure so as to recover this expenditure up front; and
- (iii) in the absence of norms regulated utilities can incur non-prudent expenditure and seek its reimbursement.

(f) BSEB has suggested that for the existing transmission system O&M expenses for the year 2003-04 or actuals whichever is less should be considered and for the new transmission system 1.5% of the capital cost or actuals whichever is less should be considered. It has further suggested escalation rate of 4% both for the existing and the new transmission system to arrive at O&M expenses for subsequent years.

(g) POWERGRID has argued that taking most efficient region as norm on all India basis would not reflect the difficult being faced in different regions because of prevailing conditions in the region due to the terrain, wind zone, environmental, geological, political, law and order and also size of transmission network. The present methodology of deriving O&M charges per km of line-length and per bay based on actual expenses over the last five years and normalisation to avoid a spike should be preferred. This methodology takes care of actual expenses and technological advantages with time.

(h) POWERGRID has also referred to the frequent failures of converter transformer. It has stated that at present there are 56 converter transformers in operation and 8 nos. spare converter transformers with a total cost implication of Rs.1020 crores approximately. According to POWERGRID, average cost of repair for each unit is about Rs.5 to 6 crore. In future, as more inter-regional links will be constructed, the number of converter transformers is likely to be three times to the existing level. POWERGRID has contended that huge expenditure towards their repair cannot be met on the basis of the existing O&M norms and have to be covered under machine break down policy for which insurance premium rate is very high (about 1.5%). In view of this, POWERGRID has sought this premium to be 'pass through' arrangement in addition to the existing O&M norms.

**Analysis of O&M expenses**

3.61 We have noted that most of the stakeholders have opined in favour of benchmarking of O&M expenses on per bay or per ckt-km basis. The benchmarking of O&M expenses in case of POWERGRID will also remove regional variations in the O&M expenses tabulated below based on calculations for the current tariff period:

**Table- 3.16**

| **Region** | **Normative O&M expenses (Rs lakhs) for the Year 1999-2000** | |
|---|---|---|
| | **Per bay** | **Per ckt-Km** |
| Northern | 11.5894 | 0.456 |
| Western | 9.9546 | 0.2796 |
| Southern | 14.8413 | 0.448 |
| Eastern | 14.0831 | 0.6456 |

3.62 POWERGRID is a single entity and physical size of the regions should not be a limitation for overall optimisation. It has to optimise its operations so as to remove variation in O&M expenses across the regions. We believe that other factors cited by POWERGRID to justify the regional variations do not affect O&M expenses significantly. POWERGRID had submitted data regarding O&M expenses for 5 years from 1995-96 to 1999-2000 for arriving at O&M expenses for the current tariff period. The Commission had applied the prudence check on the same, which had resulted in the allowable O&M expenses for these 5 years to be less than those booked by POWERGRID, by 10% to 13% in various regions. POWERGRID has subsequently submitted data regarding O&M expenses for the years 2000-01 and 2001-02. O&M expenses per bay and per ckt-km for various regions for these two years calculated as per the methodology described in the existing notification are given below:

**Table- 3.17**

| | NR | | SR | | WR | | ER | |
|---|---|---|---|---|---|---|---|---|
| Items | 2000-01 | 2001-02 | 2000-01 | 2001-02 | 2000-01 | 2001-02 | 2000-01 | 2001-02 |
| Total O&M expenses(Rs. Lakhs) | 11039.63 | 10937.58 | 6030.46 | 4710.40 | 5786.38 | 4704.40 | 5562.37 | 4581.57 |
| LL (Average line length) | 12938.14 | 13475.65 | 6847.04 | 6884.30 | 9180.00 | 9192.00 | 4754.50 | 5028.00 |
| BN (Average number of bays) | 231.5 | 250.0 | 106.0 | 106.5 | 119.0 | 121.0 | 93.0 | 94.0 |
| AVOMLL(OML/LL) | 0.60 | 0.57 | 0.62 | 0.48 | 0.44 | 0.36 | 0.82 | 0.64 |
| AVOMBN(OMS/BN) | 14.31 | 13.13 | 17.07 | 13.27 | 14.59 | 11.66 | 17.94 | 14.62 |

*We have not taken this data into account, for fixing the norms for the new tariff period 2004-09, as we have not applied the prudence check on the same. We have decided to use O&M expenses per ckt-km of line-length and per bay for Western Region as allowed in the current tariff (2001-04) as the benchmark. Normative O&M expenses per ckt-km and per bay as allowed by the Commission during the current tariff in respect of Western Region are given below:*

**Table- 3.18**

| Western Region | 2001-02 | 2002-03 | 2003-04 |
|---|---|---|---|
| Normative O&M Expenses for lines (Rs Lakh per ckt-km) | 0.3142 | 0.3330 | 0.3530 |
| Normative O&M Expenses for Substations (Rs Lakh per bay) | 11.1850 | 11.8561 | 12.5675 |

The escalation factor @ 6% was considered in the above calculations.

3.63 The existing escalation formula in the Notification dated 26.03.2001 is as under:

Escalation = 0.45 X CPI-IW + 0.55 WPITR

Where CPI-IW is the Consumer Price Index for Industrial Workers
WPITR is computed as a weighted average of relevant components (listed below) selected from disaggregated WPI series (1993-94=100).

| <u>COMMODITIES</u> | <u>WEIGHT</u> |
|---|---|
| 1. Cotton Cloth | 0.90306 |
| 2. Paper & Paper Products | 2.04403 |
| 3. Rubber & Plastic Products | 2.38819 |
| 4. Paints Varnishes & Lacquers | 0.49576 |
| 5. Turpentine, Synthetic Resins, Plastic Materials etc | 0.74628 |
| 6. Non-Metallic Mineral Products | 2.51591 |
| 7. Basic Metals Alloys & Metals Products | 8.34186 |
| 8. Machinery & Machine Tools | 8.36331 |
| 9. Transport Equipment & Parts | 4.29475 |
| All the Above (WPITR) | 30.0931 |

$WPITR = \frac{\sum_{i=1}^{9} wiWPIi}{\sum_{i=1}^{9} wi}$ where $WPI_i$ is the Wholesale Price Index for the ith sub-group and $w_i$ is its respective weight

3.64 Based on the above escalation formula, the escalation for the past 5 years i..e. from 1998-99 to 2002-03 works out to 7.91%, 2.62%, 4.32%, 3.60% and 3.18% and the average escalation for the past 5 years works out to 4.33% which is rounded off to 4%. Accordingly, as per existing tariff notification the normative O&M expenses allowed by the Commission during the existing period has been revised based on 4% escalation factor.

The revised values for normative O&M expenses per ckt-km of line-length and per bay for Western Region would be as under:

**Table- 3.19**

| Western Region | 2001-02 | 2002-03 | 2003-04 |
|---|---|---|---|
| **Normative O&M Expenses for lines (Rs Lakhs per ckt-km)** | 0.308 | 0.32 | 0.333 |
| **Normative O&M Expenses for Substations (Rs Lakhs per bay)** | 10.974 | 11.413 | 11.87 |

3.65 As discussed above, since O&M expenses per ckt-km of line length and per bay of the Western Region are to be used as benchmark, the values for 2003-04 in the Western Region have been taken as base values and escalated @ 4% to arrive at norms for the next tariff period (2004-09). These work out as under:

**Table-3.20**

| | 2004-05 | 2005-06 | 2006-07 | 2007-08 | 2008-09 |
|---|---|---|---|---|---|
| **O&M Expenses (Rs Lakhs per ckt-km)** | 0.346 | 0.360 | 0.375 | 0.390 | 0.406 |
| **O&M Expenses (Rs Lakhs per bay)** | 12.34 | 12.84 | 13.35 | 13.89 | 14.45 |

3.66 We are aware that it would not be feasible for other regional POWERGRID systems to catch this benchmark within a short span of time. We, therefore allow a “catch-up period” of 5 years (from 2003-04 to2008-09) for Eastern, Southern and Northern Region to catch this benchmark. Based on the above, the norms of O&M expenses per bay and per ckt-km for these regions shall be as under:

**Table- 3.21**

| O&M Expenses in Rs Lakh per ckt-Km of line (with base year as 2003-04) | | | | | | |
|---|---|---|---|---|---|---|
| Region | Base Year | New Tariff Period | | | | |
| | | Catch-up Time | | | | |
| | 2003-04 | 2004-05 | 2005-06 | 2006-07 | 2007-08 | 2008-09 |
| Northern Region | 0.543 | 0.516 | 0.488 | 0.461 | 0.433 | 0.406 |
| Southern Region | 0.535 | 0.509 | 0.483 | 0.458 | 0.432 | 0.406 |
| Eastern Region | 0.769 | 0.696 | 0.624 | 0.551 | 0.479 | 0.406 |

**Table- 3.22**

| O&M Expenses in Rs Lakh per bay (with base year as 2003-04) | | | | | | |
|---|---|---|---|---|---|---|
| Region | Base Year | New Tariff Period | | | | |
| | | Catch-up Time | | | | |
| | 2003-04 | 2004-05 | 2005-06 | 2006-07 | 2007-08 | 2008-09 |
| Northern Region | 13.82 | 13.94 | 14.07 | 14.20 | 14.32 | 14.45 |
| Southern Region | 17.70 | 17.05 | 16.40 | 15.75 | 15.10 | 14.45 |
| Eastern Region | 16.79 | 16.32 | 15.86 | 15.39 | 14.92 | 14.45 |

3.67 We believe that transition from the presently allowed values (in 2003-04) to the benchmark values in 2008-09 is achievable through efficiency gains. This can be seen from the actual O&M expenses for the year 2000-01 and 2001-02 of POWERGRID where there has been substantial reduction in O&M expenses from the previous year. We make it clear that the relaxation in norms during catch-up period is applicable to regional systems of POWERGRID only and other licensees will have to follow the benchmark O&M costs per ckt-km and per bay (as applicable to Western Region in the above tables).

3.68 On the issue of frequent failures of the converter transformers and the prayer of the POWERGRID to allow actual insurance for the same as passthrough, we believe that the problem of frequent failures of the converter transformer is not generic in the sense that it is peculiar to the POWERGRID system only. This is clear from the extract of the discussion (reproduced below) in the CIGRE (International Council on Large Electric Systems), Group 14 (General Report for 2002 Group 14 Session August 30, 2002 available at http://www.tc.umn.edu/~chris143/CIGRE2002SC_B4/Page7/Page7.html)

> "The perception that the converter transformer performance is having significant negative impact on overall performance of HVDC projects prompted WG 14.04 to establish a Task Force for the "Analysis of HVDC System Performance Correlated to Converter Transformer Performance". The Task Force Chairman, Mr. Christofersen, reported on the preliminary findings of their investigation. The results show that the converter transformer performance in the vast majority of HVDC projects has been fairly good. It is only the failures in transformers in three projects – precipitated in one case by years of continued overload operation, aggravated in another case by unavailability of spares – that skewed the statistics for the average performance of all the HVDC projects. The Task Force has not been able to make a credible quantitative comparison of converter transformer performance with high power transformers in ac transmission due to lack of sufficient data on the latter. Based on cursory review of available data, it was the view of Mr. Christofersen that the performances of the two are not significantly different."

3.69 The Commission in its order dated 15.01.2001 on the issue of grid disturbance in Northern Region had observed that

> "While the Commission did not examine the technical issues involved nor the responsibility of the suppliers, what came out clearly during the hearings was the failure of equipment supplied by one supplier namely M/s. BHEL, while there was no failure whatsoever of the equipment supplied by the other supplier, namely M/s. ABB. Since the consequences of such failures are grave on the operation of the grid and the economy of the country, we consider it necessary to advise the central government to immediately explore ways of improving the quality of the existing equipment, without waiting any further for repairs which have not been successful for the last one year."

3.70 We are of the opinion that the best course would be that POWERGRID should insist on the performance guarantee from the suppliers of the equipment. We firmly believe that beneficiaries are no way responsible for the quality of the equipment procured by POWERGRID. The higher premium asked for by the insurance agencies may also be due to frequent failures of the converter transformers in the past. In view of the above, we do not find any merit in the argument for additional premium cover, over and above already included in the normative per bay and per km expenses.

3.71 However, in case of abnormal O&M expenses arising due to circumstances beyond the control of transmission licensee, the transmission licensee has the liberty to approach the Commission for allowing such abnormal expenses on merits of each case.

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## CHAPTER 4

## Capital Cost

4.1 Capital Cost is the most important aspect in a cost-based regulation. It is, therefore, pertinent to discuss the current practice with regard to capital cost as followed by the Commission for the tariff period 1.4.2001 to 31.3.2004. The regulations issued by the Commission deal with the capital cost in respect of thermal and hydro power projects as below:

> *"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 or as approved by an appropriate independent agency as the case may be. The project cost shall include reasonable amount of capitalized initial spares.*
>
> *The actual capital expenditure incurred on completion of the project shall form the basis for fixation of tariff. Where the actual expenditure exceeds the approved project cost, the excess expenditure as allowed by the Authority or an appropriate independent agency shall be considered for the purpose of fixation of 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 into between the Generating Company and the beneficiary provides a ceiling on capital expenditure, the capital expenditure shall not exceed such ceiling for computation of tariff."*

4.2 The provisions with regard to capital cost in respect of inter-state transmission system as contained in the Commission's notification dated 26.3.2001 are also reproduced below:

> *"*
>
> *(a) The capital expenditure of the Transmission System shall be financed as per the approved financial package set out in the techno-economic clearance of the Authority or as approved by an appropriate independent agency, as the case may be.*

*(b) The capital cost shall include capitalised initial spares for the first 5 years of operation. The approved project cost shall be the cost which has been specified in the techno-economic clearance of the Authority or as approved by an appropriate independent agency, as the case may be.*

*(c) 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 as approved by the Authority or an appropriate independent agency, as the case may be, shall be deemed to be the actual capital expenditure for the purpose of determining the tariff, provided that excess expenditure is not attributable to the 'Transmission Utility' or its suppliers or contractors:*

*Provided further that where a transmission services agreement entered into between the Transmission Utility and the beneficiary provides a ceiling on capital expenditure, the capital expenditure shall not exceed such ceiling."*

**Impact of the Electricity Act, 2003**

4.3 The Electricity Act, 2003, stipulates that any generating company may establish, operate and maintain a generating station without obtaining a license under this Act, if it complies with the technical standards relating to connectivity with the Grid as specified by the Authority. The hydroelectric generation, subject to certain level of capital expenditure shall, however, be scrutinised by the Authority to accord its techno-economic clearance. This implies that, by and large, techno-economic clearance/concurrence of the Authority may be available for most of the hydro power generating stations which may come under the jurisdiction of the Commission. In the case of inter-state transmission, which is a licensed activity, the individual license holder will have to get the capital cost approved from the Commission. In the case of NTPC as well as PGCIL, the capital cost of the projects, which is not to be approved by the Authority, may be approved by the Board of Directors of the respective companies. Even in the absence of techno-economic clearance or concurrence of the Authority, the Government of India may be according investment approvals in those cases. Since the capital cost is a major factor in a cost-based tariff mechanism, the Commission will have to verify the capital cost for the purpose of tariff. The Commission is keen that only efficient technology is adopted keeping in view the over all cost over the life of the asset. The Commission in its current notification dated 26.3.2001 had prescribed for notification of an "Independent Agency" for the purpose of approval of the capital cost in certain cases. No such independent agency has been notified by the Commission so far, as the necessity for the same did not arise. The Commission is not keen at the moment to notify the independent agencies for approval of the capital cost. The Commission will examine the capital cost issues as and when the utilities approach the Commission with adequate details. The examination can be done by the Commission itself, or if required, assistance of consultants and any other agency could be obtained at that stage.

**Normative Project Cost Vs Actual Project Cost**

4.4 Some of IPPs have advocated for a normative project cost for determination of tariff. The normative project cost means laying down a fixed number for various types of projects, say in Rupees crore per MW for coal/lignite/gas/hydro projects and for transmission projects in Rupees lakh per KM or per bay. By following this approach, tariff can be determined on the basis of the normative project cost irrespective of the actual expenditure. The normative project cost approach requires that all other parameters in the determination of tariff such as debt-equity ratio, depreciation, interest on loan, O&M, interest on working capital, operational parameters should be specified on normative basis. Once a normative cost is assigned, regulation becomes minimal and simple. By adopting the normative cost approach, it is possible to do away with revision of tariff in case of additional capitalization on account of R&M, life extension etc. These are the obvious advantages of the normative project cost approach.

4.5 In cost-plus approach, there is a tendency to increase the rate base to maximise the return, whereas in case of normative cost approach there is incentive to complete the project at the minimum cost, because savings, if any, will be to the account of generating company or the transmission utility. Further, in cost-plus approach, manufacturers keep a watch on the trend of the project costs being approved and accordingly raise their equipment costs to that level. Manufacturers try to quote prices with higher margin and pressurize the developers to get the same approved by the Regulators. Even a well-meaning developer intending to economise on cost gets sandwiched. If a stringent normative project cost is decided, then it is likely that manufacturers will realign their prices in order to sell their products.

4.6 We have tried to analyze the past and present data of project costs, particularly the project cost cleared by CEA in the recent past. We have found considerable variations in the project cost of thermal power generating stations among even of the same size and capacity. Accordingly, we could not establish a relationship between project cost variations and their site specific features. Inspite of the limitations in arriving at a normative cost, we feel that it would be desirable to move in the direction of normative project cost for various types of thermal power generating stations. However, this requires a deeper study and analysis and further interaction with the stakeholders before such norms could be proposed. We are also of the view that hydro project costs are highly site-specific with predominant costs involving civil works and as such are not amenable for specifying normative project costs. As regards transmission schemes, although the equipment costs could be arrived at on normative basis, yet the total cost of a transmission system could vary widely on account of configuration adopted and terrain over which the transmission lines pass. As such, for the time being, we have no option but to continue with the cost-plus regime.

4.7 Capital Cost or Rate Base for the existing projects is already fixed by the Commission for various generation and transmission assets for the period 2001-04. The basis for such capital costs is the approval of the capital cost by CEA/Central Government which is further subject to actual capital expenditure and prudence check by the Commission. In all these cases, no changes to the admitted capital cost is contemplated during the next (2004-09) tariff period.

**Initial Capital Expenditure and Additional Capital Expenditure**

4.8 With regard to the actual capital expenditure, the Discussion Paper on terms and conditions of tariff further discusses two types of expenditures, namely:

(a) Initial Capital Expenditure; and
(b) Additional Capital Expenditure.

4.9 The initial capital expenditure would continue to be the actual capital expenditure as on the date of commercial operation of the unit or the generating station, as the case may be. For the existing projects of the central power sector utilities, any additional capital expenditure was being allowed to be added to the project cost for the purpose of tariff as per project-specific notification of the Central Government. However, the position changed with the Commission's tariff notification dated 26.3.2001 which under clause 1.10 provides that:

> *"Tariff revisions during the tariff period on account of capital expenditure within the approved project cost incurred during the tariff period may be entertained by the Commission only if such expenditure exceeds 20% of the approved cost. In all cases, where such expenditure is less than 20%, tariff revision shall be considered in the next tariff period."*

4.10 In thermal power generating stations, such expenditure after the date of commercial operation may be substantial but unlikely to exceed 20% of the cost. NTPC has contended that disallowing revision of tariff on account of capitalisation of such expenditure till the next tariff revision will amount to penalizing the utilities. It has further been contended that this may have adverse effect on the date of commercial operation of the generating station, which may get deliberately extended to the next tariff period and will not be in the interest of the beneficiaries as it will have the consequence of adding IDC apart from depriving the beneficiaries of the utility. We have seen that certain works such as administrative building, colony construction, construction of roads, etc. are taken up after the date of commercial operation of the generating station. Works relating to ash pond and ash disposal system are taken up in stages after the date of commercial operation of the generating station. There are also the deferred liabilities on account of certain balance payments, etc. in various contracts. Therefore, we find considerable merit in the arguments of NTPC. As such, we allow revision of tariff on account of additional capitalisation once in the tariff period.

4.11 Most of the stakeholders including the State Electricity Boards, State Utilities, IPPs and the Central Power Sector Utilities have not objected to the continuation of the existing arrangement of actual capital expenditure as the basis for the tariff fixation. It has emerged that in case the existing cost-plus approach is to be continued, there is a need to specify a cut off date or time beyond the date of commercial operation of the generating station up to which expenditure in the original scope of work could be allowed to be completed and capitalised as part of original project cost. Any expenditure beyond the cut off date may have to be treated differently even if in the original scope of work, except works relating to ash pond and ash disposal system. In order to give sufficient time to complete the balance works after the date of commercial operation of the generating station and to close the contracts, we feel that a minimum period of around one year needs to be provided for this purpose. As such, we decide the cut off date to be the first financial year closing after the date of commercial operation of the generating station. We also feel that a clear methodology for treatment of "additional capitalisation" needs to be specified before and after the cut off date.

4.12 The Commission has been allowing additional capitalisation in the past, after scrutiny and prudence check of various items of additional capitalisation. There is a need to streamline this procedure so that the utilities as well as the beneficiaries would know in advance as to which items would qualify for additional capitalisation and which items would not. We, therefore, order that the following procedure shall be adopted while examining such cases, namely:

(1) The following capital expenditure within the original scope of work actually incurred after the date of commercial operation and up to the cut off date may be admitted by the Commission, subject to prudence check:

(i) Deferred liabilities;
(ii) Works deferred for execution;
(iii) Liabilities to meet award of arbitration or the satisfaction of the order or decree of a court; and
(iv) On account of change in law.

Provided that original scope of works along with estimates of expenditure shall be submitted along with the application for provisional tariff:

Provided further that a list of the deferred liabilities and works deferred for execution shall be submitted along with the application for final tariff after the date of commercial operation of generation station.

(2) The capital expenditure of the following nature actually incurred after the cut off date may be admitted by the Commission, subject to prudence check:

(i) Deferred liabilities relating to works/services within the original scope of work;
(ii) Liabilities to meet award of arbitration or satisfaction of the order or decree of a court;
(iii) On account of change in law;
(iv) Any additional works/services which have become necessary for efficient and successful operation of the generating station, but not included in the original project cost; and
(v) Deferred works relating to ash pond or ash handling system in the original scope of work.

4.13 Once the Commission is satisfied that the items for which additional capitalisation is sought by the utility is covered under any of the above categories, the Commission may consider such capitalisation, subject to the following conditions:

(1) Additional capitalisation within the original scope of work to be serviced in the normative debt : equity ratio;

(2) Expenditure on account of replacement of old assets to be considered after writing off the entire value of the original assets from the original capital cost;

(3) Expenditure on account of new works not in the original scope of work to be serviced in the normative debt : equity ratio of 70:30; and

(4) Expenditure on account of renovation and modernisation and life extension to be serviced on normative debt : equity ratio of 70:30 after writing off the original amount of the replaced assets from the original capital cost.

4.14 As regards, capital cost of new projects established after enactment of the Electricity Act, 2003, which does not stipulate techno-economic clearance/concurrence of the Authority for certain types of projects as discussed earlier, the Commission has to examine the capital cost in all cases of cost-based tariff regulations. For this purpose, the equipment cost details of the project, the financing package proposed to be used in execution of the project, schedule of construction, indicating commissioning of individual units and the date of commercial operation of the station in case of generating stations, and the date of commercial operation of the individual lines/sub-station and the date of commercial operation of the entire scheme in case of transmission system, shall be furnished alongwith the sources and uses of funds. Necessary calculations for interest during construction, financing charges and foreign exchange rate variation during the construction period shall also be furnished, wherever applicable in the formats already prescribed by the Commission. Wherever formats are not prescribed, the details are required to be furnished by the Utilities clearly bringing out information called for by the Commission.

**Capitalised Initial Spares**

4.15 The issue of spares in the capital cost has also been a subject matter of debate in the past. While the cost of initial spares procured alongwith the main plant and equipment was capitalised in some cases, in other cases, the spares were kept in the inventory separately. The Commission observed that in certain cases of tariff fixation, Central Government had allowed the cost of spares as a part of capital cost on estimate basis. To remove all these confusions and anomalies, we hereby direct that for the purpose of tariff, the capital cost shall include capitalised initial spares as a percentage of plant and equipment cost (and not the project cost), subject to the following ceiling norms, in respect of various assets:

(1) Coal/Lignite based projects: 2.5%;
(2) Gas/Liquid based projects: 4.0%;
(3) Hydro power projects: 2.5%; and
(4) Transmission system: 1.5%.

**<u>Apportionment of capital cost amongst units/stages</u>**

**Existing provisions**

4.16 Clause 1.6 of the notification dated 26.3.2001 provides as follows:

*"For the purpose of tariff, the capital cost of the project shall be broken up into stages and by distinct units forming part of the project. The common facilities shall be apportioned on the basis of the installed capacity of the units and lines/sub Stations where break up of the project cost is not available and in case of on-going projects. All fresh petitions shall also be filed in the form as per Appendix I".*

The Commission in its order dated 21.12.2001 had also observed as follows:

*"1.7.9 Since a generating station normally is a multi unit one and since there are common costs and the units/lines are commissioned in stages, there is a specific problem of identifying the capital costs for the commissioned unit. In particular, the proportion of common costs to be charged to the completed units/lines has to be decided. It may also have to be kept in mind that progressive completion of units does not necessarily mean definite capitalisation of cost on a progressive basis. The ultimate capitalisation is bound to be done on the completion of the entire station/line. Therefore this problem is a tentative one till the completion of*

*the entire station/line. In future, all capital costs shall be broken up, into stages and by distinct units forming part of the project. The utility may move the Commission for tariff in respect of the completed units though the station may be incomplete and as such the tariff petition for the station may not be forthcoming. For the future as stated, the project report shall give a stage-wise capitalisation. This equally applies to segments of a line in case of transmission".*

*"1.7.11 The Commission is of the opinion that the apportionment of common costs is an approximation whatever is the method for it. It is also a temporary problem, which would cease as soon as all units are commissioned. Any approximation resulting in over recovery or under recovery of tariff for a short period should ultimately get neutralised a longer period of time. The Commission would not like to micro manage the system by devising an elaborate mechanism for a purely tentative tariff. It is convinced that no serious dislocation of tariff would take place in case common facilities are apportioned with reference to capacity of the different units and the total capacity of the station/line as is presently being done. As such the Commission considers it a simple and viable solution to distribute the common capital costs on the basis of the installed capacity with reference to total capacity of the station/line in the case of ongoing projects whose project costs have not given the desired breakdown. However, any unfairness or absurdity if noticed shall be decided on case to case basis".*

4.17 We are of the view that the existing provision for apportionment of capital cost for the partially completed/commissioned stations on pro-rata capacity basis should continue for the tariff period 2004-09.

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# CHAPTER 5

## FINANCIAL NORMS

5.1 The Discussion Paper on terms and conditions of tariff dealt with the following financial issues:

1. Rate of Return: Two options for rate of return, namely, return on capital employed and return on equity were discussed. The comments received from various stakeholders on the Commission's notification dated 26.3.2001 were also brought out in the Discussion Paper; and

2. Rate Base: The rate base was explained in terms of initial capital expenditure and increase/decrease on account of any additions/deletions to the capital expenditure and accounting for FERV.

5.2 Discussions on these issues will be incomplete, if we do not consider the following aspects in one stretch:

a) Gross fixed assets vs net fixed assets;
b) ROCE vs ROE;
c) Existing assets vs future assets;
d) Normative debt and equity vs actual debt and equity;
e) Post tax return vs pre tax return;
f) Refinancing;
g) Rebate/late payment surcharge; and
h) Promoting investments.

### Gross Fixed Assets vs Net Fixed Assets

5.3 Generators like NTPC and NLC have proposed that the admitted capital cost for the existing generating stations and expenditure actually capitalised on the date of commercial operation for new generating stations may be considered as rate base. They have also suggested that prudence check on the capital expenditure after it has been incurred may not be desirable. They have also sought notification of few independent agencies for technical and financial appraisal of the projects before the projects are approved for investment. Damodar Valley Corporation has expressed the view that capital cost be considered on actuals as on the date of commercial operation for new projects and based on audited accounts for the existing assets subject to prudence check by the Commission. Damodar Valley Corporation is yet to approach the Commission for any tariff setting. NHPC has argued in favour of following the existing methodology.

5.4 The State Electricity Boards of West Bengal, Maharashtra, Punjab, Bihar, Kerala and many others have expressed the view that the rate base should be the approved capital cost limited to the actual expenditure. Some of them have also expressed a view that capitalised initial spares should also be part of the rate base.

5.5 Assam State Electricity Board, APTRANSCO and few others have suggested that the net fixed asset method be adopted for tariff setting. We have received quite a few comments from the State Electricity Regulatory Commissions, which we like to deal with. APERC has proposed to continue with the liability side approach. MPERC has highlighted that although the liability side approach for determination of rate base leads to certain level of double counting, it is preferred to continue with the same as incentive for investment in the sector. Rajasthan Electricity Regulatory Commission has suggested to continue with the present practice, while Karnataka ERC is of the view that net fixed assets model should be adopted if ROCE is adopted.

5.6 IPPs are of the opinion that the liability side approach only should be adopted. Similar views have been expressed by some of the lending agencies as well. Shri Mrutunjay Sahoo, Joint Secretary & Financial Advisor, Ministry of Power has suggested use of normative capital cost related to certain quantum of power availability. BSES in its presentation on 12.11.2003 has advocated for setting up of tariff based on normative parameters, including normative capital cost so that the investor can estimate his future revenue flows, which will provide adequate certainty. Shri Bhanu Bhushan in his personal capacity has proposed adoption of net fixed asset approach. Shri K.P. Rao has suggested that the rate base should be the approved project cost or actual completion cost as on the date of commercial operation, whichever is less, but subject to notional equity of 30%.

5.7 We have considered the method of tariff setting followed in the Central Government notifications, procedure followed by the licensees for their tariff setting and the comments received from various stakeholders. We are conscious of the decisions taken in the previous tariff setting order in December 2000 based on which the tariff for the period 2001-04 is being set. We have also examined tariff setting process followed by the administered price mechanism, which indicates that the net fixed asset concept is being followed in such cases. The practice, which has been followed in respect of all the central power sector utilities except NLC, has been to arrive at the tariff based on the liability side approach and to provide for return on equity over the entire life of the asset. Only in the case of NLC, the tariff has been mutually agreed between the utility and the beneficiaries based on the rate base corresponding to net fixed assets. The Commission has adopted the liability side approach for the tariff period 2001-04. The essential features of the liability side approach as discussed in the Commission's order dated 21.12.2000 of para 2.8.6 are reproduced below:

*(a) In the liability side approach the value of the assets on the ground would be ignored subject to the investments being used in the core activity; whereas in the assets side approach the value of the core assets on the ground are taken for arriving at the base;*

*(b) As a corollary, in the liability side approach the depreciation is independent of the rate base determination. In other words, depreciation is considered as the amount recovered to be used exclusively for replacement of the assets;*

*(c) In the liability side approach, the base would get reduced only to the extent of the loan repayment since equity is never repaid except on the dissolution of the company. As such return on equity would be allowed so long as there are assets to generate the revenue. When applied to a station/line 'equity' represents the net worth of the company invested in the project;*

*(d) The liability side approach provide scope for double counting of the equity in case the depreciation amount instead of being used for replacement of capacity is otherwise used for addition to the capacity. In the assets side approach this situation is averted; and*

*(e) Underlying the assets side approach is the concept of return of equity with option to the investor to reinvest or quit; whereas the liability side approach provides an incentive to the investors to sustain his interest in the operation and motivates in sustaining his capacity and continue to render the service.*

5.8 We order the following methodology to be adopted for the tariff period 1.4.2004 to 31.3.2009:

(a) In respect of the central power sector utilities, the liability side approach shall be continued subject to other orders of the Commission with regard to debt/equity ratio whether actual or normative, calculation of interest on actual or normative loan etc., as explained in other parts of this order; and

(b) In respect of the old generating stations of Neyveli Lignite Corporation where tariff was decided by mutual consent, the existing approach of Net

> Fixed Asset concept shall be continued as this arrangement has been entered into between the parties consciously and the equity investment of NLC in these projects is very high as compared to the debt component.

5.9 In respect of all the new generating stations of Neyveli Lignite Corporation, commissioned on or after 1.4.2004, the liability side approach shall be followed. We are consciously taking this view with the intention of bringing uniformity in the tariff setting process in the case of generating companies and transmission utilities which are under the jurisdiction of the Commission.

5.10 Adoption of the liability side approach is preferred because of the fact that the country is facing both demand and energy shortages of differing magnitude in different regions. Huge investment is required for capacity addition as well as for expansion of transmission network over the next 10 years. The Central Government has already programmed to add capacity of over 100,000 MW by 2012. The central power sector utilities will have to play an important role in establishing a sizable portion of this additional capacity and, therefore, there is an absolute need to provide for reasonable cash flows which will facilitate mobilisation of additional internal resources by these companies who have the mandate for reinvestment of the internal resources in power sector itself. We are of the view that in the larger interest of the sector in the current scenario of shortages, it is necessary to provide for certain additional cash flows, one of the ways being providing return on the gross equity throughout the life of the asset, as has been decided by the Commission in the terms and conditions of tariff notified on 26.3.2001.

**ROCE vs. ROE**

5.11 NTPC has suggested that the Return on Capital Employed (ROCE) concept on total investment is acceptable. It has also recommended following of liability side approach and fixing up the ROCE for the entire tariff period. NLC has preferred the return on equity approach. NEEPCO has envisaged the adoption of ROCE model. NHPC, SJVNL and THDC have expressed their preference for return on equity approach. PGCIL has also preferred adoption of return on equity approach. PSEB, KSEB, BSEB, MSEB, TNEB, RVPNL, Orissa Power Generation Corporation, Grid Corporation of Orissa, West Bengal Power Development Corporation, APERC, RERC and OERC have preferred adoption of ROCE approach.

5.12 We have examined the pros and cons of the two options in the light of the comments received from the stakeholders and the arguments addressed before us during the open hearing. The debt market is not fully developed in Indian scenario. Insurance funds, pension funds and other long-term funds are just entering the market. Debt from these sources may be available for a longer term at competitive rates. Under these circumstances, normative rate of debt for arriving at ROCE may be an uphill task. For the existing generating stations for which tariff is already notified by the Central Government as well as the Commission in the past, the practice followed is to provide for return on equity and interest on loan separately instead of ROCE. This arrangement shall be continued during the tariff period commencing from 1.4.2004 as well.

5.13 For all new projects, debt-equity ratio of 70:30 shall be adopted (maximum equity permissible would be 30%, less than 30% equity will be preferred.) Any equity above the level of 30% shall be treated as normative based on which interest on loan on normative basis shall be provided.

**Existing Assets vs. Future Assets**

5.14 For the purpose of application of different parameters discussed in this Order, the existing assets mean and include all the power stations and transmission assets and any other assets, which are approved by the competent authority before the issue of this Order. All future assets or new assets mean and include all assets commissioned on or after 1.4.2004.

**Debt: Equity**

5.15 The present practice followed in the tariff setting in case of the central power sector utilities is to provide for either normative debt-equity ratio or actual debt : equity ratio. RVPNL has suggested debt-equity ratio of 70:30 with equity of not more than 30% for the purpose of determining tariff. APTRANSCO has suggested adoption of debt-equity ratio of 80:20. OPGC, KPCL and OERC have favoured 70:30 debt-equity ratio while GRIDCO, Orissa and TNERC have preferred debt-equity ratio of 80:20. IPPs and the lending agencies have preferred a debt-equity ratio of 70:30.

5.16 In the light of the views expressed in the Discussion Paper on terms and conditions of tariff, the comments received from various stakeholders and the observations made during the hearing by various agencies, we are of the view that it is necessary to follow a normative debt-equity of 70:30 for all new projects. Wherever the tariff has already been set by the Commission, the debt-equity ratio shall remain the same as considered by the Commission. For all other cases, normative debt-equity ratio of 70:30 shall be adopted. We are unable to prescribe a single normative debt-equity ratio for all old and new projects due to the fact that the utilities have not been able to furnish the debt and equity of the projects from the date of commercial operation, despite various instructions from the Commission to this effect. The debt-equity ratio being discussed in this paragraph is the debt-equity ratio on the date of commercial operation of the project/system. After the date of commercial operation, with repayment of loan every year, the debt-equity ratio would be changing continuously. Any mid course change over without knowing the original debt-equity ratio and the exact debt and equity in a generation project or transmission scheme would affect the tariff either way. The Commission is strongly in favour of simplification of the procedure for tariff setting as has been expressed in the Discussion Paper on terms and conditions of tariff by adopting the ROCE approach and provide full freedom to the utilities to optimise debt and equity. But the lack of information such as future interest rate, determination of original debt and equity etc. is not facilitating adoption of this simplified approach.

5.17 Another issue which is frequently raised by the beneficiaries, is the recommendation of the K.P.Rao Committee that the equity is to be reduced by the amount of depreciation once the loan is fully repaid. The stakeholders have indicated during the open hearing that the Central Government had accepted the K.P.Rao

Committee report in toto. Since the Commission has resorted to normative debt : equity ratio of 70:30 for new projects, the Commission may review the normative debt : equity ratio of 50:50 in case of existing assets.

5.18 We direct that for all the projects for which tariff has been ordered by the Commission, the debt-equity ratio as considered in these orders shall be followed. For all new projects, which are declared under commercial operation on or after 1.4.2004, a normative debt-equity ratio of 70:30 shall be adopted. In case the equity is less than 30%, the actual equity shall be adopted and if the equity is higher than 30%, the excess equity shall be treated as normative loan. This view is necessitated by the fact that equity capital is expensive as compared to debt capital.

**Post-Tax Return Vs Pre-Tax Return**

5.19 The Discussion Paper on terms and conditions of tariff dealt with the issue of miscellaneous provision of 0.5% to take care of the income-tax element in the ROCE model. NTPC has suggested increasing this proposed 0.5% to 1.7%. NHPC had argued that the suggestion of 0.5% increase in ROCE as miscellaneous provisions towards income-tax, etc. is ad hoc and not based on any study. NLC, SJVNL, THDC, etc. have favoured the continuation of the existing ROE on post tax basis. DVC suggested converting the ROE into pre-tax instead of post-tax with provision of payment of actual income-tax if it happens to be higher. PSEB has argued in favour of restricting the income-tax to the return of normative equity or actual income-tax liability which ever is lower. Some of the SEBs have favoured the miscellaneous provision of 0.5% in the

ROCE towards income-tax as suggested in the Discussion Paper. SEBs have also argued that the income tax has to be paid by the person who earns the income and should not be reimbursed. We have examined the written submissions as well as the oral arguments during the hearing. The issue of income-tax has to be seen in the light of whether a pre-tax or post-tax return is specified. In case a post-tax return is specified, income-tax should be reimbursed by the beneficiaries while if a pre-tax return is provided, the income-tax liability will have to be borne by the utility itself. The issue of grossing up of income-tax in the later alternative needs to be examined in detail. Even in the case of market mechanism for any good service, income-tax paid by the company indirectly gets passed to the end consumer indirectly through the pricing of the good service. Hence, the argument of the beneficiaries that the income-tax has to be paid by the agency which earns the profit does not get justified. We are, therefore, inclined to adopt the return on post-tax basis in the tariff period 2004-09 as explained in later part of this order.

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# CHAPTER 6

## Annual Fixed Charge

6.1 Having discussed the individual parameters and different options within the parameters, the annual fixed charges are described in the following sections. The annual fixed charges comprise of the following namely:-

1. Interest on Loan;
2. Return on Equity;
3. Depreciation including Advance against Depreciation;
4. O&M Expenses;
5. Interest on Working Capital; and
6. Income-tax.

Of the above, O&M expenses have already been discussed in Chapter 3. The income-tax component of tariff is being discussed in Chapter 8. The other components of annual fixed charges are being discussed in this Chapter.

**<u>Interest on Loan</u>**

6.2 The Interest on Loan shall be calculated based on the following method, namely:-

(a) Wherever the tariff is already fixed by the Commission for the period 2001-04 or for any other prior period, the debt capital considered in such cases shall be reckoned for carrying it forward;

(b) Wherever normative loan is considered, the normative repayment shall be worked out on a pro rata basis vis-à-vis the actual loans; and

(c) In case of actual loan, the actual interest on loan duly taking into account, the schedule of repayment of actual loan shall be allowed. The interest on loan calculation, in case of actual loans shall be done for each loan separately to arrive at the total interest on loans.

6.3 In case of normative loan, the rate of interest shall be arrived at by calculating the average rate of interest of actual loan outstanding. This average interest rate would then be applied on the normative loan outstanding.

**Refinancing**

6.4 The issue of refinancing of loan has been raised by most of the beneficiaries in the context of falling interest rates. This issue is also discussed in this Order in the section relating to FERV. Carrying on the debt at a higher rate of interest, when loans with lower interest rates are available, is not considered to be in the overall interest of the consumers. This is more so, in the context of the loans which were contracted with interest rates at or around 17% or 18 % whereas the current interest rates are in the range of 11% to 12 %. Therefore, every effort should be made by the utilities to refinance the costlier loans with cheaper loans. In such a case, any pre-payment charges involved or any other liability for the previous loan shall be borne by the beneficiaries. Any refinancing should be in the ultimate interest of the consumers and should not be a source of profit for the utilities.

**Foreign Exchange Rate Variation**

6.5 The Discussion Paper on terms and conditions of tariff outlines the options available with regard to Foreign Exchange Rate Variation (FERV). These are:

(a) Payment of Foreign Exchange Rate Variation arising on account of interest payments and payments of installments of loans, at actuals, on quarterly or yearly basis;

(b) Payment of Foreign Exchange Rate Variation in accordance with Accounting Standard - 11 (AS - 11) of Institute of Chartered Accountants of India (ICAI); and

(c) Payment of Foreign Exchange Rate Variation in accordance with AS - 11 of ICAI after dividing FERV component into normative debt and equity.

6.6 The Discussion Paper also referred to FERV in a different context that in the return on capital employed model, the need to provide for FERV may not arise.

6.7 It is pertinent to discuss the existing provisions as contained in the notification dated 26.3.2001 for handling exchange rate variation. These are as follows:

*"(a) Extra rupee liability towards interest payment and loan repayment actually incurred in the relevant year shall be admissible, provided it directly arises out of FERV and is not attributable to utility or its suppliers or contractors. Every utility shall follow the method as per the AS - 11 as issued by the ICAI to calculate the impact of exchange rate variation on loan repayment.*

*(b) Any FERV to the extent of the dividend paid out on the permissible equity contributed in foreign currency subject to the ceiling of permissible return shall be admissible. This as and when paid may be spread over the 12 month period in arrears. "*

6.8 The above part of the notification clearly brings out that the foreign exchange risk needs protection. The protection, as far as debt is concerned is to be allowed both on account of repayment of the principal and the interest to the extent not already included in the tariff which is decided upfront. As regards exchange rate variation on equity, to the extent of dividend paid out on permissible equity contributed in foreign currency, subject to the ceiling of permissible return has an element of exchange rate risk built into the tariff.

6.9 The Central Government in its notification dated 30.3.1992 had also provided for the protection of the exchange rate variation by the following terms:

> *"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 their suppliers or contractors".*

6.10 As regards the return on foreign equity, the notification of the Central Government dated 30.3.1992 provided that 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 percent in the currency of the subscribed capital.

6.11 From the above discussion, it can be seen that in accordance with the past practice FERV risk has to be borne by the beneficiaries. Nevertheless, the extent of foreign exchange investment either by way of debt or by way of equity has to be carefully decided. The foreign currency which is to be used in a particular project or scheme, is also required to be chosen very carefully. It may not be advisable to resort to investment in foreign currencies which are volatile in nature. The percentage of foreign currency to be used in a project or a scheme should be predetermined and will be subject to the approval of the competent authority and the final approval of the Commission as it has a direct bearing on the tariff.

6.12 The submissions made by the stakeholders and the experts are summarised below:

(a) The central power sector utilities in general had suggested that FERV should be a pass-through the miscellaneous provisions suggested in the Discussion Paper should not be considered and FERV pass-through should be worked out based on actuals. Some of these utilities have also suggested that FERV should be considered on actual basis as a pass-through item on yearly basis.

(b) NHPC pointed out that the financial implications on tariff arising on account of change in the methodology for working out FERV should be computed for any project from the date of commercial operation and any under or over-payments should be adjusted in the particular year in which the change in methodology is proposed.

(c) Most of the beneficiaries and State Electricity Regulatory Commissions suggested that the consumer should bear the risk associated with FERV. They also favoured treatment of variation by treating this as a profit or loss in the respective years in which it arises and charging it to the revenue expenditure.

(d) The beneficiaries and the State Electricity Regulatory Commissions have also suggested that FERV should be provided on the basis of actual payment of interest and installments of foreign currency loans on yearly basis, provided foreign currency component of loan was envisaged in the original means of financing of the project. If there is gain in the event of swap of the existing foreign currency loan with new loans, the gain should be passed on to the beneficiaries.

(e) IPPs have sought retention of the protection for exchange rate variation in respect of both debt and equity.

6.13 So far the Commission has viewed the issue in the following context:

(a) The Commission's existing tariff notification valid up to 31.3.2004 provides protection of exchange rate variation as per the AS - 11, by changing the capital cost which then gets divided between equity and debt for further treatment.

(b) In a separate petition filed by the NTPC for " approval of management of foreign exchange rates through hedging", the Commission came to the conclusion that -

*" In the light of the above discussion, we feel that balance of convenience lies in continuing to follow the existing frame work on the question raised in the present petition. This should, however, not be construed to preclude the petitioner from following the policy formulated by it at its own risk and costs. Gain or losses accruing as a result of following the policy shall be of the petitioner alone. We make it clear that the State Utilities shall neither be liable for any losses nor entitled to gains in case the petitioner pursues the policy"*

(c) In a specific petition of NTPC for approval of tariff, the Commission had taken a view that the benefit of lower interest rate shall be passed on to the beneficiaries in case a fixed interest loan is swapped by another fixed interest loan.

(d) Another major development which has taken place recently is the amendment to the Accounting Standard (AS - 11). The earlier version of the AS - 11 came into effect on 1.4.1995. The revised AS - 11 will come into effect from 1.4.2004 for the purpose of accounting. The revised AS - 11 applicable from 1.4.2004, recognises the foreign currency transactions as below:

*The initial recognition includes the borrowed capital in foreign currency as well as assets acquired which is denominated in a foreign currency. According to the revised AS - 11, the foreign currency transactions should be recorded, on initial recognition in the reporting currency by applying to the foreign currency amount the exchange rate between the reporting currency and the foreign currency at the date of the transaction. The recognition of exchange differences arising on the settlement of monitory items at rates different from those at which they were initially recorded during the period, should be recognised as income or as expenses in the period in which they arise. The major change in the revised AS - 11 vis-à-vis the earlier As - 11 is that while the existing AS - 11 provides for adjustments in the carrying amount of the respective fixed assets, (there by changing the capital cost which then gets divided between the debt and equity for further treatment), the revised AS - 11 provides for the treatment of exchange rate variation as income or expense which in effect is a revenue expenditure. The issue of FERV has received different treatment at different points in time. Even the revised AS - 11 which is to take effect from 1.4.2004 envisages that the same supercedes AS - 11 issued in 1994, <u>except that in respect of accounting for transactions in foreign currencies entered into by the reporting enterprise itself or through its branches before the date this standard comes into effect, AS - 11 (1994) will continue to be applicable.</u> Even while revising the accounting standard, ICAI have* *carved out an exception to account for the earlier transactions as per the AS - 11 (1994).*

6.14 We have examined the present practice of the Commission alongwith the observations of the stakeholders and the experts and also in the context of revision to the AS - 11. The treatment of exchange rate variation has undergone frequent changes over the last 10 years and also there was no uniformity in its application to different utilities. We are in favour of following an uniform procedure for all the utilities for the purpose of tariff, notwithstanding the fact that the accounting of FERV may be done differently in accordance with AS - 11 (1994) or As - 11 (revised 2003). We, therefore, order that FERV shall be provided for on a year-to-year basis as income or as expense in the period in which it arises and shall be adjusted by the utilities/beneficiaries on a year to year basis. In the earlier tariff period, the Commission has allowed the capitalisation of FERV on the outstanding loans as on 31.3.2001 and the capitalisation of FERV for the period 2001-02 to 2003-04 was to be claimed from the beneficiaries directly. Therefore, FERV after 31.3.2004, shall be claimed with reference to the exchange rate difference on the date of payment and 31.3.2004 or the date of drawl, whichever is later. No separate petition need to be filed before the Commission for this purpose. Disputes, if any, arising on account of this settlement, may be brought before the Commission, following the procedures laid down by the Commission in this regard, for appropriate adjudication.

6.15 The Commission has also examined the existing provisions regarding FERV on the foreign currency equity invested. The present notification links FERV on equity to the extent of dividend paid out on the permissible equity. This may not facilitate retention of surpluses in the business and the tendency will be to declare maximum dividend. The Commission, therefore, orders that the return on equity up to the specified limit shall be allowed in the currency in which the equity was invested and payment made in Indian Rupees based on the exchange rate prevailing on the scheduled date of billing.

**Return on Equity**

6.16 The Commission had proposed two alternatives for deciding the Rate of Return which are - (i) Return on capital employed (ROCE), that is, return on total investment. For this purpose, a normative debt-equity ratio, normative interest rate for the debt and normative rate of return for the equity are to be fixed so that an over all cost of capital could be determined. This method was proposed by the Commission as one of the alternatives to provide a free hand to the investors so that they may optimise the debt and equity capital and take advantage of the financial market conditions. This method obviates the need for reimbursement of FERV during the year, if the notional debt carries the notional interest rate of rupee loans. The other alternative suggested by the Commission was to continue with the existing procedure of providing normative return on equity and the interest on loan based on rate of interest applied on balance actual or normative outstanding loan, as the case may be.

6.17 The Discussion Paper dealt with the different aspects of return on equity at length. The return on equity described as the return on total investment less borrowings or return on normative equity with the interest on loan being provided separately on actual basis, with quantum of debt on normative or actual basis along with FERV. The comments received from the stakeholders are discussed hereunder.

6.18 NTPC suggested that the return on equity should not be reduced below 16% irrespective of the debt-equity ratio and argued that reducing the return on equity to 12% will give wrong signals to the investors. NLC expressed the view that post-tax return on equity should be 16%. Power Grid in its presentation had sought increase of the return on equity beyond 16 % in view of the fact that the IRR, taking into account the gestation period is coming down. Tehri Hydro Development Corporation argued for retention of return on equity at 16%. NHPC pleaded for continuation of 16% post-tax return. Almost all the State Electricity Boards and their successor entities argued in favour of reducing the return on equity, especially when normative debt-equity ratio has been taken as 50: 50 for all the existing projects. Since we do not have the data regarding debt and equity invested by all the utilities in individual projects on the date of commercial operation, we are unable to deal with this issue. 50:50 is not an ideal debt-equity ratio when there is a big disparity between the interest rates prevailing and the return on equity allowed. Equity being the risk capital, risk premium has to be added to the bank rate and therefore, return on equity has to be higher than the prevalent interest rates. Having said this, how high it should be is a matter of debate. We are also conscious of the fact that initially the return on equity to central power sector utilities was provided at 10% which was subsequently increased to 12% and further increased to 16% in November 1998 by the Central Government. If the argument at that time was to provide for a return on equity corresponding to the increase in interest rates, it should also be true now when the interest rates are falling. An oft-repeated argument by the utilities that return on equity should provide enough returns for them to add future capacities may not hold good under these circumstances. We have already expressed a view in the later part of this order that all the investment required by the utilities cannot be covered by tariff alone. We shall deal with this issue of investment requirement in detail separately.

6.19 The Return on Equity to the Central Power Sector Utilities was fixed at 16% post-tax in November, 1998. The interest rates which were prevailing at that time, were quite high. Presently the interest rates are around 11% to 12%. The Commission has not disturbed the normative debt : equity ratio of 50:50 for the existing projects. The normative debt : equity ratio of 70:30 prescribed now by the Commission is applicable in case of new projects only which are to be commissioned on or after 1.4.2004. The projects, which are approved by the competent authority after the Central Government Notifications dated 30.3.92 or 16.12.1997 for generation and transmission projects respectively, are by and large executed with debt : equity ratio of 70:30, barring a few exceptions. Most of the IPP projects were executed with debt equity ratio of 70:30. It is well understood that equity is a risk capital and therefore, will carry a premium for the risk over and above the interest rates. The risks which are faced by the Central Power Sector Utilities, are not the same as the risks faced by the IPPs, especially with regard to the payment risk. In the case of Central Power Sector Utilities the Government has provided the comfort of tripartite agreement for ensuring prompt payments, where as such a facility is not available to IPPs. The Central Power Sector Utilities would also be receiving certain additional incomes by way of interest earnings on the bonds issued by the State Governments for the outstanding dues. Further, the bonds are also redeemable over a period of time.

6.20 Keeping all these factors in view, we have decided in favour of providing a post-tax return @ 14% for the Central Power Sector Utilities and @ 16% in case of IPPs. In case, IPPs are provided same payment security mechanism like the Central Power Sector Utilities, ROE in their case shall also be reduced to 14%. The return on equity is based on post-tax and accordingly, the income-tax shall be reimbursed by the beneficiaries as per the provisions discussed in the section relating to income-tax.

**Depreciation and Advance against Depreciation**

6.21 During the tariff period 2001-2004, the Commission provided for depreciation on a straight line basis, spread over the entire life of the asset. It should be noted that the practice of allowing depreciation has been changed from time to time. Prior to 1992, depreciation was being allowed over the useful life of the asset. In 1992, the provision for depreciation was changed to provide a higher rate of depreciation, thus de-linking the life of the asset from the rate of depreciation. This imbalance between the useful life of the asset and the depreciation rate was further aggravated by the increase in the depreciation rate to yield an over all depreciation rate of 7.5% for thermal power generating stations. This change in rate had altered the depreciation rates for the transmission system as well. However, the depreciation rates in case of the hydro power generating stations remained static and the hydro power generating stations were allowed to recover their depreciation over their useful life of 35 years and for meeting cash flow requirements for debt repayments, advance against depreciation was provided. The change in the depreciation rates had resulted in the high front loading of tariff and issues like interest of the investor after 12 years by which time the 90% depreciation is recovered came to the fore and became an issue for debate in many private power projects. The Commission had also observed the other views expressed during the open hearing that the accelerated depreciation was meant for providing additional cash flows for reinvestment in power sector. In the case of IPPs, providing for accelerated depreciation appeared to be to meet the debt service obligations. Since the problem of principal repayment remained an issue for hydro power generating stations alone consequent to 1994 upward revision of the depreciation rates for thermal power stations, advance against depreciation was provided for hydro power generating stations. Here again, repayment period of 12 years was considered to calculate advance against depreciation. We have come across instances where loan tenure was less than 12 years and hence the hydro utilities were unable to meet their debt service obligations even with advance against depreciation. Further, wherever the repayments were made beyond the depreciation and advance against depreciation amounts, the benefit of reduced interest on loan in subsequent years was passed on to the consumers. The Commission intends to deal with all these issues based on the feed back made available during the open hearing.

6.22 An important recent development is the enactment of the Electricity Act, 2003 which does not provide for prescribing of depreciation for the purpose of accounting by the Ministry of Power which was a practice under the Electricity (Supply) Act, 1948.

6.23 As regards maintenance of accounts, the depreciation rates to be adopted by various utilities need to be clearly understood. While some arguments were leading towards following of the rates provided in the Schedule XIV of the Indian Companies Act, 1956, certain other arguments were leading to the adoption of the rates notified by the Central Government under Section 43A of the Electricity (Supply) Act, 1948. The latter arguments probably stem from the provision of sub-section (2) (a) of Section 185 of the Electricity Act, 2003. This issue will also be debated in the later part of the order dealing with the provisions for depreciation.

6.24 Depreciation in accounting term is a measure of the wearing out, consumption or other loss of value of a depreciable asset, arising from use, effluxion of time or obsolescence through technology and market changes. Depreciation is allocated so as to charge a fair proportion of the depreciable amount in each accounting period during the expected useful life of the asset. Depreciation includes amortization of assets whose useful life is predetermined.

6.25 For the treatment of depreciation, three views are generally expressed. These are:

(a) Depreciation represents a cash flow for repayment of loan;

(b) Depreciation represents a return of capital; and

(c) Depreciation is a charge for the replacement of the assets consumed.

6.26 The provisions relating to depreciation applicable during the current tariff period 2001-04 are:

(i) The value base for the purpose of depreciation shall be the historical cost of the asset;

(ii) Depreciation shall be calculated annually as per straight line method at the rates of depreciation as prescribed in the Schedule attached to the notification:

Provided that the total depreciation during the life of the project shall not exceed 90% of the approved original cost. The approved original cost shall include additional capitalization on account of foreign exchange rate variation also;

(iii) Advance against depreciation (AAD), in addition to allowable depreciation, shall be permitted wherever originally scheduled loan repayment exceeds the depreciation allowable as per schedule and shall be computed as follows:

AAD = Originally scheduled loan repayment amount subject to a ceiling of $1/12^{th}$ of original loan amount minus Depreciation as per schedule

(iv) On repayment of entire loan, the remaining depreciable value shall be spread over the balance useful life of the asset;

(v) Depreciation shall be chargeable from the first year of operation. In case of operation of the asset for part of the year, depreciation shall be charged on pro-rata basis; and

(vi) Depreciation against assets relating to environmental protection shall be allowed on case-to-case basis at the time of fixation of tariff, subject to the condition that the environmental standards as prescribed have been complied with during the previous tariff period.

6.27 The Discussion Paper highlighted the issues arising out of the provisions currently in force. The comments received from the stakeholders are briefly discussed hereafter.

6.28 The central power sector utilities have argued that depreciation is meant for replacement of assets and that the rate of depreciation should be adequate to facilitate loan repayment. It is stated that the accelerated depreciation at 7.84% for coal-based generating station and 8.24% for gas-based generating stations be provided instead of linking depreciation with the life of the asset. In the alternative, it is urged that depreciation may be provided in accordance with the Companies Act or in accordance with Optimised Depreciated Replacement Cost (ODRC) principle.

6.29 The beneficiaries comprising of the State Electricity Boards and their successor Transcos have argued that the depreciation rates may be continued as per the Commission's notification dated 26.3.2001. Broadening the scope of depreciation or increasing the tariff for capacity addition has been opposed. It is urged that if depreciation is increased for the present assets and new assets are created with such excess recovery of depreciation, return on equity and interest on loan should be linked to the extent of funding being provided from other sources. They have submitted that advance against depreciation may not be allowed on year-to-year basis but only after taking into account the total cumulative amount of depreciation towards repayment of loans. It is stated that debt service obligation should be provided for in full in each year in the tariff as per the approved financial package and no depreciation be provided separately. According to the beneficiaries, the provision of higher depreciation results in front loaded tariff, which the States are not able to sustain at least during the initial stages of the reform period. In view of this, it is argued that the depreciation rates should be kept low so that the viability of the Discoms and Transcos improves.

6.30 Many of the licensees and IPPs suggested that depreciation be allowed at the rates notified by the Central Government in 1994. In such a case, neither advance against depreciation nor development surcharge needs to be provided. Most of the lenders have suggested that the debt service obligation should be fully met by way of depreciation and advance against depreciation. It is also stated that the rates of depreciation for tariff and accounting purposes be identical, and should be in line with the provisions of the Companies Act. A suggestion is made that 12 years period prescribed as repayment period for calculation of AAD may be reduced to 8 to 10 years.

6.31 It emerges that there is a clear divide in the opinion of generating companies and the central power sector utilities on one hand and the State Electricity Boards and other state utilities on the other. While the central power sector utilities have sought to liberalise the provisions for charging of depreciation in the tariff, the beneficiaries, the state utilities, have strongly supported the existing methodology for charging of depreciation over the useful life of the asset and have suggested to continue it as far as depreciation and advance against depreciation are concerned. It was also argued by some of the experts that financial strength of the State Electricity Boards, etc, became unviable only after the increase in the depreciation rates in 1994. It was further argued that while doing so, the intention of the Central Government was to provide for adequate cash flows to IPPs for meeting their debt service obligations through accelerated depreciation. It has, however, unwittingly increased the tariff across the board, which the State Electricity Boards could not recover from the consumers.

6.32 We have examined the issue in great detail. We are of the view that depreciation is a measure of consumption or other loss of value of a depreciable asset over its useful life and, therefore, the provisions currently in force in regard to depreciation are justified. In view of this, the schedule for recovery of depreciation appended to the Commission's notification dated 26.3.2001 needs to be continued for the next tariff period. In view of the provision of advance against depreciation to meet the debt service obligations, wherever required and to avoid high front-loading of tariff, the Commission is not in favour of adopting the depreciation rates as per the Companies Act, 1956 for the purpose of tariff. Depreciation Schedule included in the Companies Act, 1956 is meant for maintenance of accounts and is not binding for the purpose of tariff. Since the Commission is providing for depreciation over fair life of the asset and Advance Against Depreciation for meeting debt service obligations, there is no need to adopt the depreciation rates provided in the Companies Act for the purpose of tariff.

6.33 The issue of shorter tenure for loan by the funding agencies was also argued before us. We do appreciate the problems faced by the investors with regard to loan repayment. Keeping in view the difficulties in obtaining a loan with a repayment period of 12 years, we are of the opinion that the repayment period of 10 years after the date of commercial operation, in case of new projects for the purpose of calculation of advance against depreciation needs to be considered. This change should be acceptable to the beneficiaries as with repayment of loan, the interest liability in subsequent years will go down. We do not favour linking advance against depreciation to the cumulative depreciation, because of frequent changes in the depreciation rates, many refinancing activities which were undertaken in the past were affected. And revisiting of all these parameters would be more cumbersome, especially when many of the stakeholders are preferring to switch over to tariff based on norms.

## INTEREST ON WORKING CAPITAL

**Present practice**

6.34 Presently, the interest on working capital is based on the normative parameters on consideration of which the total working capital is calculated. The interest on working capital on the quantum of working capital so calculated based on norms is provided on the basis of the short-term prime lending rate of State Bank of India. Continuation of the same method, with some minor modifications was proposed by majority of the stakeholders.

**Thermal Power Generating Stations**

6.35 The working capital in respect of the thermal power generating stations covers:

(a) Fuel cost for one month and reasonable fuel stocks as actually maintained but limited to fifteen days for pit head generating stations and thirty days for non pit-head generating stations, corresponding to the “target availability”;

(b) Sixty days stock of secondary fuel oil, corresponding to the “target availability”;

(c) Operation and maintenance expenses (cash) for one month;

(d) Maintenance spares at actual subject to a maximum of one per cent of the capital cost but not exceeding one year's requirements less value of one fifth of initial spares already capitalized for first five years;

(e) Receivables equivalent to two months' average billing for sale of electricity calculated on "target availability"; and

(f) The interest rate for this purpose shall be the cash-credit rates prevailing at the time of tariff filing.

**Hydro Power Generating Stations**

6.36 The terms and conditions of tariff presently in vogue lay down that interest on working capital shall cover:

(a) Operation and maintenance expenses for one month;

(b) Maintenance spares at actual but not exceeding one year's requirements less value of one fifth of initial spares already capitalized for the first five years;

(c) Receivables equivalent to two months of average billing for sale of electricity; and

(d) The interest rate for this purpose shall be the cash-credit rates prevailing at the time of tariff filing.

**Inter-State Transmission**

6.37 The existing tariff regulations prescribe that interest on working capital shall cover:

(a) Operation and maintenance expenses (cash) for one month;

(b) Maintenance spares at a normative rate of 1% of the capital cost less 1/5th of the initial capitalized spares. Cost of maintenance spares for each subsequent year shall be revised at the rate applicable for revision of expenditure on O & M of transmission system;

(c) Receivables equivalent to two months' average billing calculated on normative availability level; and

(d) The interest rate for this purpose shall be the cash credit rates prevailing at the time of tariff setting.

6.38 In the Discussion Paper, it was stated that the need for requirement of an element towards interest on working capital has to be viewed with reference to the cash flows for meeting various commitments by the regulated entity. If interest on working capital cannot be given separately, it has suggested an alternative to adjust slightly upwards the miscellaneous provision of 0.50% on ROCE to take care of the working capital requirements. The suggestions received from stakeholders are summarised below:

(a) NTPC has suggested to continue with the provision of interest on working capital on normative basis as per the existing practice. However, it has submitted that deduction of $1/5^{th}$ of the capitalised spares cost from the cost of one-year maintenance spares is not justified;

(b) NHPC has argued for continuation of the existing system. However, the maintenance spares may be taken as 1% of the capital cost in case of new projects and on the basis of five years' average consumption in case of old projects;

(c) NLC in its submission has also argued for continuation of the existing provision of working capital;

(d) NEEPCO has submitted that even after the scheme for one time settlement of dues, the payment position has not improved, as none of the NER beneficiaries barring ASEB have established Letter of Credit for ensuring regular payment of current dues despite having signed the tripartite agreement. It has suggested that the elements of working capital should remain as it is now;

(e) PGCIL has submitted that as per bulk power transmission agreements signed between Power Grid and beneficiaries, the payment of monthly transmission charges is to be made within a period of 30 days. However, as per tripartite agreements, the payment is to be made within sixty days. In case of non-payment by the due date, the surcharge would be applicable after sixty days. It has argued that in view of the above, three months' receivables instead of two months may be allowed in the working capital. It has also submitted that the receivables and O&M expenses are two different factors. While the receivables are the past dues not yet paid by the consumers thereby forcing the utility to arrange that much cash from alternate sources, O&M expenses is the future liability for which cash provisioning is required to be met through short term borrowing;

(f) DVC in its submission has recommended the working capital as per the existing norms of the Commission and the interest at the actual cash credit PLR, to be revised, if necessary, at least once in a year as per actual;

(g) BSES Ltd. has suggested retaining the existing norms for calculating working capital. However, the interest on working capital should be allowed in the tariff on a normative basis. It has submitted that the interest on working capital should not be linked to ROCE, as with the reduction of capital base, working capital interest recovery through tariff would reduce. It has suggested that interest rate may be taken as SBI PLR plus 3% which is the normal spread charged by the bankers to a "A" rated borrower;

(h) Tata Power in its presentation during the open hearing has suggested to allow 0.50% of the total capital as interest on working capital.

(i) CESC has suggested continuing the existing working capital norms. It has suggested that where any utility's past entitlement has been approved but allowed to be recovered over interest free installments, such receivables should be specifically considered within the normative working capital or as regulatory asset. It has also suggested that any linkage with PLR may be done only with due regard to the creditworthiness of the utility;

(j) Torrent Pvt. Ltd. has argued for norm based working capital requirement leaving enough discretion with ERCs to amend norms to provide for the specific circumstances of each utility on case to case basis for geographical location of the generating station, socio-economic environment, political stability, and weather;

(k) GMR Power in its presentation during the hearing has suggested to continue the existing norms;

(l) GPEC Pvt. Ltd. has suggested that the interest on working capital should be paid on a normative basis as per Central Government norms. It has also suggested that the rate of interest may be linked with the PLR of nationalized bank with 1% mark up for the credit risks;

(m) UPRVUNL has submitted that the Central Sector is getting the prompt payment of their dues from state distribution power utilities but state generating companies are not getting such prompt payments. UPRVUNL is getting only 80% to 85% payments of its energy bills from UPPCL and the receivables have gone up equivalent to 5 months of energy sale. It has suggested that receivables equivalent to at least 3 to 4 months may be provided in the working capital. It has also suggested that present provisions of fuel cost and O&M cost should be retained as these are required for providing adequate working capital for the preceding months. It has also submitted that consumable spares are required for one year's consumables over and above the capital spares and therefore, the existing provision for deduction 1/5$^{th}$ capitalised spares is not justified. It has argued that maintenance spares, subject to maximum of 1% of the capital cost but not exceeding one-year's requirement may be included in the working capital. However, after the useful life of generating station, increased ceiling of 2% of the capital cost instead of 1% may be allowed. It has also submitted that the working capital requirement depends on the variable cost component. The variable cost of fuel of power generating stations far away from pit-head generating stations would be more than the variable cost of power generating stations on pit-head generating stations. It has therefore, suggested that slight upward adjustment in ROCE to take care of working capital requirement is not justified. It has also suggested not to link the interest on working capital with the actual working capital loan undertaken and adoption of prevailing cash credit rate for computation of interest on working capital;

(n) WBPDCL has suggested continuing the provision of interest on working capital based on normative basis as per the existing practice;

(o) KPCL has suggested continuing the existing norms for working capital. It has also suggested that rate of interest may be linked to cost of funds of the working capital of the generator. It has also submitted that in case of non-provision of interest on working capital separately, a minimum of 1% additional return on equity may be included in the exiting ROE;

(p) UPPCL has submitted that the O&M expenses of one month may not be a part of the working capital requirement as O&M expenses for two months are already a part of working capital in the form of two months receivables. Moreover, O&M expenses are paid in cash only after incurring the expenditure;

(q) GRIDCO has requested to allow interest on net working capital instead of gross working capital as available under the existing norms as a portion of the gross working capital is financed by the creditor and supplier of goods and services. It has suggested that 60 days of secondary fuel oil corresponding to target availability may also be excluded as already the cost of fuel for one month is allowed. It has also submitted that return on equity on margin money may not be allowed however, margin money may not also be deducted from the working capital. It has also suggested that the rate of interest may be linked with the market rate instead of bank PLR as now-a-days, it is possible to raise funds from banks and open market rates are lower than the PLR. In their presentation during hearing they also suggested that base of interest rate on working capital may be fixed for the tariff period and the increase or decrease may be passed on to the beneficiary like FPA. It has suggested to exclude the salary and wages from O&M expenses as the same is paid after completion of the month. It also suggested that under the present improved transportation and communication link, 30 days of secondary fuel oil may be allowed instead of 60 days;

(r) RRVPNL has submitted that receivables for 60 days include all the components of a monthly bill viz. fuel cost, cost of secondary fuel, O&M expenses, cost of spares etc. and including the individual components along with the receivables tantamount to double accounting and inflates the working capital requirement of the regulated entity. It has suggested that either only 45 days of receivables or the components of cost (O&M, fuel cost and maintenance spares) should be the quantum of working capital requirement of the utilities. It has also suggested that to encourage efficiency in cash flow management, interest rate may be linked to some risk premium over PLR, say 0.50% to 1% over PLR. It has also suggested that interest on margin money included in the project cost may not be included in computation of the interest on working capital;

(s) TNEB has submitted that the level of inventory as allowed under the existing notification is not maintained by any of CGS. Further, all the generating stations are having more than one unit in service and it may not be required to keep so much inventory round the year as some of the units will be under planned maintenance. Each state has a refinery and it may not be difficult to get secondary fuel oil at short notice. It has suggested that in case of NLC TPS II only 15 days of secondary fuel oil may be allowed as inventory. It has further suggested that inventory level may be reduced to 10 days of coal/lignite stock for pit head generating stations and 20 days for other generating stations and 15 days of secondary fuel oil consumption to meet any eventuality in the supply of fuels. TNEB has also submitted that all the major expenses incurred during the month are paid at the end of the month and no advance payment is involved. Even in the case of supply of consumables, the payment is made after receipt of materials. It has suggested that the components of working capital may be revised based on the practices followed in maintaining inventory, purchase procedure etc. by respective agencies. It has also suggested that interest rate on working capital may be based on prevailing PLR as on the year of tariff fixation;

(t) PSEB was of the view to continue the existing provision with the exception that one month O&M charges should not be included as the same is already included in the two months receivables. It has also suggested to link the rate of interest to PLR of nationalised bank/PFC as the interest rate of PFC are lower;

(u) Govt. of Chattisgarh/ CSEB has submitted that working capital requirement of 0.5% suggested in the discussion paper would be more appropriate. It has also suggested that average O&M expenses should be on the basis of the certificate of the Cost Accountant on the basis of previous 5 years' cost and adding an escalation based on inflation rate. It has also suggested that in case of transmission and distribution companies, an additional provision of 5% on R&M expenses on ad-hoc basis for increase in expenditure due to expansion/creation of new lines, sub-stations etc. may be made;

(v) MSEB have suggested that recovery of interest on working capital through tariff may not be permitted and the utilities may pay the same from interest/return and depreciation;

(w) ASEB has suggested that receivables for 15 days may be provided considering payment against power purchase made by the bulk power customers through LC on monthly basis. It has also submitted that inclusion of O&M expenses in the working capital together with receivable means double loading. It has suggested that there is no need for working capital, however, fuel stock being maintained by the generator may be allowed;

(x) WBSEB has submitted that since two months' O&M expenses is a part of 2 months receivables , inclusion of one month's O&M expenses additionally will be an extra burden on the consumers. It has also submitted that since the norms for capital cost include reasonable amount of capitalised initial spares, cost of spares should not be included in the working capital;

(y) APTRANSCO has submitted that the generating company has a certain level of cash flow to finance a part of its working capital requirement without need to take recourse to borrow from the market and therefore, working capital requirement of the generating company may be considered after taking into account the cash liquidity available. It has also suggested to exclude one month's O&M expenses since two months' receivables already include two months' O&M expenses;

(z) KSEB has suggested to exclude one month's O&M expenses as two months' receivable include two months' O&M expenses;

(aa) BSEB has suggested to delete the interest on working capital element due to improved liquidity position as a result of the scheme for one time settlement of the State Electricity Boards dues under tripartite agreement;

(bb) Bharat Chamber of Commerce has submitted that provision of additional return of 0.5% in ROCE towards miscellaneous provision would be sufficient to take care of additional requirement of working capital after taking care of income tax liability, if any;

(cc) Utkal Chambers of Commerce and Industry Ltd has submitted that no provision should be made for interest on working capital in view of collection of depreciation every year, higher return on equity , margin kept over PLR towards interest and collection of security deposit for which interest is not paid to consumer;

(dd) IDBI in their submission have suggested that in case of imported fuels, fuel stock limit could be provided higher than the domestically sourced;

(ee) IDFC has submitted that in ROCE based approach, working capital is treated like a term loan and is left to the discretion of generator, in order to incentivise efficient inventory management practices. It is also suggested to disallow quality of service related items e.g. replacement of transformer from the definition of working capital;

(ff) PFC has submitted that considering for billing and payment time, the duration of receivables may be restricted to 30 days. It has also argued that there is no case for including the O&M expenses as most of the O&M expenses is carried out on credit basis;

(gg) Bengal National Chamber of Commerce and Industry has submitted that interest on working capital should be treated as a separate item other than O&M expenses. Provision of annual requirement of minor spares for O&M expenses at the rate of 0.5% of capital cost on generating station and machinery should be a part of O&M expenses for thermal as well as hydel generating stations;

(hh) Shri K.P. Rao, has submitted that the present composition of elements of working capital does not call for a change. He has submitted that two months' billing should not be reduced for the reason that payment record to generating company/transmission utility is not good. He has also suggested to prescribe an element of penal charges, say at 2% per month for bills not paid beyond two months;

(ii) Shri R.K. Narayan, has suggested for fixing of a single value of capital employed for interest on loan, return on equity , interest on working capital, income tax and new capital investment for R&R based on few representative plants instead of going in details for each project;

(jj) HPERC has submitted that the salaries are paid after one month and the material required for operation of the generating station is available on suppliers' credit and therefore, there is no need of working capital. However, if some working capital is required, and the company obtains the same from the bank, it should not be given separately and should be taken care of by the miscellaneous provision of 0.5% on the ROCE suggested in the clause 3.2.9 of the discussion paper;

(kk) MPERC has submitted that although there is double counting for items which are included in two months receivables but this double counting is partially accounted for as the purchaser gets discount of 1.5% for opening an LC and 1% additional for payment within due date. It has also argued for balancing the need for receivables period as the generator has two months receivable period, it can also negotiate two months payable period. However, it has not suggested doing away with the receivable as a part of working capital. During the hearing, it has suggested to allow interest on net normative working capital to be derived after deduction of fuel cost;

(ll) RERC has submitted to exclude secondary fuel oil from the fuel cost and accounting for the reduction at the time of tariff determination based on the average fuel cost for the current tariff period based on fuel stock either at the end of each week or each month. With three - four days for period of billing and three days to effect payment, only a part of O&M expenses would be required against the present provision of one month. It has also submitted that for normal maintenance, stock of spares may not exceed one-two months requirement and for capital maintenance, spares are arranged prior to, but matching with capital maintenance and therefore, stock of one year's spares may not be appropriate and only two months of stock of spares may be considered. However, in order to compute the stock of two months' consumption of spares, $1/5^{th}$ of the initially capitalised spares may be deducted from the yearly consumption of spares. It has also submitted that the working capital requirement may be reduced by the working capital margin money and also by the supplier's credit equivalent to one month or actual. It has suggested that rate of interest should be arrived on the basis of weighted average PLR of the banks of the respective utility depending on its credit rating;

(mm) TNERC has suggested a slight upward adjustment in the ROCE towards interest on working capital component at a rate to be fixed by the Commission;

(nn) OERC has suggested 30 days of secondary fuel oil and one month of receivables. It has also suggested that capitalised initial spares may be deducted in the first three years @ $1/3^{rd}$ in each year. Interest rate is suggested to be linked with prime lending rate of commercial banks;

(oo) KERC has supported the miscellaneous provision under ROCE suggested in the discussion paper as it provides simplicity in calculation and avoids controversies. It has also suggested that even in return on equity model interest on working capital could be provided by slight upward revision of ROE; and

(pp) APERC has suggested for continuation of the existing practice.

6.39 We have gone through the submissions of the stakeholders and experts. Some of the stakeholders and experts have argued that the interest on working capital may be provided on net working capital as a portion of gross working capital is financed by the creditors and supplier of goods and services. However, majority of the stakeholders do not favour any major changes in the existing system of provision of working capital requirement. In view of the above, we feel that interest on working capital may be provided as a separate element in the tariff. However, in the existing norms some of the elements of working capital e.g. fuel stock, maintenance spares etc. are related with the actual. In order to promote efficiency amongst the utilities, we are of the opinion that the elements of working capital may be linked with the norms, which would incentivise the utilities to promote efficiency in their operation.

6.40 Some of the beneficiaries have suggested that fuel cost, coal stock, secondary fuel oil, O&M expenses and maintenance spares may not be provided separately in the working capital as 2 months' receivables have already been provided in the working capital, otherwise this would amount to double counting. We have examined the issue and are of the view that although receivables have been separately provided, there is a provision for rebate for payment of bills through LC @ 2% of the bill amount and 1% rebate on the bill amount for payment within 30 days. This negates the double counting and, therefore, all the elements of working capital require to be separately provided.

6.41 It is argued by some of the beneficiaries that the existing provision of 60 days' of secondary fuel oil is on the higher side. We have examined the issue and are of the view that the provision for one month of secondary fuel oil stock corresponding to target availability should be sufficient.

6.42 Regarding maintenance spares, it has been argued that 1/5th of the initial capitalised spares may not be deducted from the maintenance spares. It has also been argued to provide the elements of working capital on normative basis. We are of the view that initial spares may be provided @1% of the plant & equipment cost at the beginning of the tariff period or date of commercial operation, whichever is later. This will remain constant during the tariff period and will not be subject to deduction of 1/5th of the capitalised initial spares therefrom.

6.43 It has been argued by some of the utilities to provide higher amount of receivables in view of the outstanding dues. The beneficiaries have argued not to provide the receivables, as it would amount to double counting. We have already examined the issue above and are of the view that the receivables may be provided as per the existing norms.

6.44 Regarding margin money, some of the respondents have argued to continue the existing practice while others have argued for not providing the same and its reduction from the working capital. Although working capital margin is an essential element in the project financing, we are of the view that the interest on working capital be allowed on the entire working capital without taking into account working capital margin, if any, included in any project.

6.45 Most of the respondents argued to link the rate of interest with PLR of some commercial bank. Some of the respondents have also argued to provide some mark up above PLR. We have observed that the banks are providing the working capital to the utilities even below PLR. We are, therefore, of the view that providing the rate of interest at PLR would be sufficient. However, there are various commercial banks having different PLR. We are, therefore, of the view that the short-term PLR of leading bank i.e. State Bank of India may be allowed in working capital.

6.46 In view of the above, the requirement of working capital may be provided as follows:

**Thermal Power Generating Stations**

Working capital shall cover:

**(a) Coal based/Lignite-based generating stations**

(i) Cost of coal or lignite for one month corresponding to target availability;

(ii) Cost of coal or lignite stock for ½ month for pit-head generating stations and one month for non-pit-head generating stations, corresponding to the "target availability";

(iii) One month's stock of secondary fuel oil, corresponding to the "target availability";

(iv) Operation and Maintenance expenses for one month;

(v) Maintenance spares @ 1% of the plant and equipment cost as on 1.4.2004 or the date of commercial operation, whichever is later; and

(vi) Receivables equivalent to two months of fixed and variable charges for sale of electricity calculated on "target availability".

**(b) Gas-based/Liquid fuel based generating stations**

(i) Fuel cost for one month corresponding to the “target availability” duly taking into account the mode of operation of the generating station on gas fuel and liquid fuel;

(ii) Liquid fuel stock for ½ month;

(iii) O&M expenses for one month;

(iv) Maintenance spares @ 1% of the plant and equipment cost as on 1.4.2004 or the date of commercial operation, whichever is later; and

(v) Receivables equivalent to two months of fixed and variable charges for sale of electricity calculated on "target availability";

**Hydro Power Generating Stations**

(a) Operation and maintenance expenses - one month;

(b) Maintenance spares - 1% (one per cent) of the plant & equipment cost at the beginning of the tariff period or date of commercial operation, whichever is later; and

(c) Receivables -2 (two) months of fixed and variable charges calculated on normative capacity index.

**Inter-State Transmission**

(a) Operation and maintenance expenses - one month;

(b) Maintenance spares - 1% (one per cent) of the plant & equipment cost at the beginning of the tariff period or date of commercial operation, whichever is later; and

(c) Receivables -2 (two) months of annual transmission charges calculated on target availability level.

6.47 Rate of interest on the above working capital would be the short-term prime lending rate of State Bank of India at the beginning of the tariff period or at the beginning of the year in which the date of commercial operation falls, whichever is later.

6.48 While arriving at this conclusion, we have also considered the fact that some of the utilities may not borrow any working capital by resorting to efficient financial management. Since funds do have alternative uses, we have deemed it proper to provide for interest on working capital on a normative basis, whether such funds are actually borrowed or not.

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# CHAPTER 7

## Energy Charges

### THERMAL POWER GENERATING STATIONS

### Existing provision:

7.1 The existing notification dated 26.3.2001 provides for methodology for computation of energy charges covering fuel cost. For stations covered under ABT, energy charges in a time block are to be worked out by multiplying rate of energy charges with scheduled generation given by Regional Load Despatch Centre ex-bus. In case of the generating stations other than those covered under ABT, energy charges are worked out by multiplying rate of energy charge with energy delivered ex-bus.

7.2 Rate of energy charge is specified in paise/kWh ex-bus on a specified date along with adjustment on account of variation in price and heat value of fuel, covering fuel cost. The rate of energy charge is a function of price of primary fuel, namely, coal or lignite in coal and lignite-fired generating station or coal or naphtha in case of lignite fuel-based generating station, GCV of primary fuel, price of secondary fuel, GCV of secondary fuel on a specified date. Therefore, the rate of energy charge is subject to adjustment on account of variation in price and heat value of fuel on month-to-month basis as follows:

> *"Initially Gross Calorific Value of coal/lignite or gas or naphtha shall be taken as per actual in the preceding three months. Any variation shall be adjusted on a month-to-month basis on the basis of Gross Calorific Value of coal/lignite or gas or naphtha actually received and burnt and actual landed cost incurred by the Generating Company for procurement of coal/lignite, oil, or gas or Naphtha, as the case may be. No separate petition needs to be filed with the Commission for fuel*

*price adjustment. In case of any disputes, an appropriate petition in accordance with the Central Electricity Regulatory Commission (Conduct of Business Regulations) 1999 shall be filed before the Commission."*

7.3 The Commission does not find any reason to alter the existing methodology for computation of energy charges given in Para 7.1 and prefers to continue with the same.

7.4 However, in so far as computation of rate of energy charge and variation in price is concerned, as stated in para 7.2, the computation of rate of energy charge on a specified date is made with reference to price and heat value of fuel corresponding to normative parameters of station heat rate, specific fuel oil consumption and auxiliary energy consumption and is subject to change with variation in price of fuel and heat value of fuel. The existing provision was in line with Ministry of Power's tariff notification dated 30.3.1992 and provides for fuel price to be actual landed cost of fuel. Accordingly, the Commission while determining tariff for the tariff period 2001-04 had allowed fuel price and fuel price adjustment based on Price Store Ledger (PSL) Register.

7.5 We do not intend to micro-manage the fuel accounting procedure as such and, therefore, prefer to delete any reference to actuals. The provision in this regard shall, therefore, be as follows:

*"Initially Gross Calorific Value of coal/lignite or gas or naphtha shall be taken as per actual in the preceding three months. Any variation shall be adjusted on a month-to-month basis on the basis of Gross Calorific Value of coal/lignite or gas or naphtha received and burnt and landed cost incurred by the Generating Company for procurement of coal/lignite, oil, or gas or naphtha, as the case may be. No separate petition needs to be filed with the Commission for fuel price adjustment.*

*In case of any disputes, an appropriate petition in accordance with the Central Electricity Regulatory Commission (Conduct of Business Regulations) 1999, as amended from time to time, shall be filed before the Commission."*

7.6 However, this calls for suitable norm for transit and handling losses in respect of coal-based generating stations, which will also be in line with the general tenor of this order to provide normative numbers in order to improve efficiency and to incentivise the generator to achieve savings.

7.7 In case of coal-based generating stations, there are losses mainly on account of theft during transit, windage losses and handling losses at the power generating station end, etc., and are unavoidable to some extent. As per the data furnished by NTPC for the period 2000-01, transit and handling losses for the NTPC coal-based generating stations are as follows:

**Table- 7.1**

| **Pit Head Stations** | | **Rail Fed Non Pit Head Stations** | |
|---|---|---|---|
| **Name of Plant/ Capacity** | **Transit & Handling Loss in %** | **Name of Plant/ Capacity** | **Transit & Handling Loss in %** |
| Singrauli STPS/ 2000 MW | 0.41 | Dadri NCTPS/ 840 MW | 1.08 |
| Korba STPS/ 2100 MW | 0.04 | Unchahar STPS/ 840 MW | 0.52 |
| Kahalgaon STPS/ 840 MW | 0.25 | Tanda TPS/ 440 MW | 3.52 |
| Vindhyachal STPS/ 2260 MW | 0.47 | | |
| Ramagundam STPS/ 2100 MW | 0.22 | | |
| Farakka STPS/ 1600 MW | 0.40 | | |
| Rihand STPS/ 1000 MW | 0.45 | | |
| Talcher STPS/ 1000 MW | 0.03 | | |
| Talcher TPS/ 460 MW | 0.24 | | |
| Average | 0.27 | | 0.80* |

*Excluding Tanda TPS

7.8 The above details show that the transit and handling losses are within the range of 0.03% to 0.47% for the pit head generating stations of NTPC with an average of 0.27%, rounded off to 0.30%. Similarly, transit and handling losses are in the range of 0.24% to 0.3.52% for the rail fed non-pit head generating stations of NTPC with Tanda TPS having very high transit and handling losses of 3.52%. Thus, excluding Tanda TPS average transit and handling losses for rail fed non-pit head generating stations of NTPC, works out to 0.80 %. We, therefore, allow normative transit and handling losses as a percentage of quantity of coal dispatched by the coal supply company as under:

| | | |
|---|---|---|
| Pit head generating stations | : | 0.30% |
| Rail fed non-pit head generating stations | : | 0.80% |

7.9 No such transit and handling losses are allowed for liquid fuel, gas and lignite-based stations. This is for the reason that liquid fuel is transported in closed wagons and, therefore, there is no scope for theft during transit. The question of windage loss and handling loss also does not arise in the case of liquid fuel. In case of NLC, the lignite is produced by NLC itself within the vicinity of the generating station and, therefore, the losses of the kind noted above should be negligible.

**Sharing of energy charges**

7.10 The energy charges shall be shared among the beneficiaries according to the drawal schedule given by the Regional Load Despatch Centre.

## HYDRO POWER GENERATING STATIONS

**Primary Energy Charges**

**Existing Provision**

7.11 Primary Energy Charges, Secondary Energy Charges and their rates are governed at present by the notification dated 26.3.2001. The notification provides that energy charges are worked out on the basis of paise per kWh rate on ex-bus energy scheduled to be sent out from the generating station after adjusting for the free power delivered to the home state.

7.12 Mathematically it is expressed as under:

Primary Energy Charge = Primary Saleable Energy (Ex-Bus) * Primary Energy Rate/(1-r)

Secondary Energy Charge = Secondary Saleable Energy(Ex-Bus)* Secondary Energy Rate/(1-r)

r = 0.12 and represents 12% free power to the home state.

Note 1

Rate of Primary Energy for all hydro stations except for pumped storage stations, and stations in the NE region is taken as 90% of the lowest variable charges for the central sector thermal power stations of the concerned region.

Note 2

In the case of hydro power generating stations in the NE Region, the rate of primary energy is taken as 90% of the lowest variable charges of the central sector thermal power stations of the Eastern Region plus transmission charges (paise/kWh) of the Eastern Region. This is based on our order dated 1.11.2002 in petition No. 59/2001 in respect of Loktak H.E. station of NHPC located in the N.E. Region.

7.13 We do not propose to disturb the existing methodology. Accordingly, the methodology for calculation of primary energy charges as presently in vogue, shall continue to be followed for the tariff period commencing on 1.4.2004.

**Secondary Energy Rate**

**Existing Provision**

7.14 In the current tariff period, the rate of secondary energy is equal to that of primary energy.

**Views of Stakeholders**

7.15 We have received wide-ranging views of the stakeholders on the rate of secondary energy to be considered for a hydro power generating station. These are summarised hereunder:

(a) NHPC has stated that rate of secondary energy should not be less than the rate of primary energy because it incentivises the generating station to generate additional secondary energy. The generating of secondary energy is beneficial, as the beneficiaries are not required to pay the capacity charges on the secondary energy as payable for the primary energy.

(b) NEEPCO has also expressed views similar to that of NHPC.

(c) RVPNL has suggested that rate of secondary energy should be fixed at 25% of the primary energy rate.

(d) Orissa Electricity Regulatory Commission has suggested that secondary energy be priced at 60% of the primary energy rate.

(e) Utkal Chamber of Commerce & Industry has suggested secondary energy rate at 20% of the primary energy rate.

(f) PGCIL has suggested secondary energy to be priced at 25% of primary energy rate.

(g) KPCL has suggested to give incentive for secondary energy portion at least 50% of the primary energy charge.

(h) GRIDCO has pleaded that the primary energy rate should be limited to maximum of 25% of lowest variable cost of thermal power generating station. This will change rate of secondary energy accordingly.

(i) Bharat Chambers of Commerce has stated that after change-over to capacity index concept from availability concept, the risk of non-realization of full capacity charges by the generating stations are considerably reduced and secondary energy remains 'zero cost' energy for all practical purposes. Therefore, the pricing of secondary energy requires review and the same should be set at such a level so that the generating companies and the beneficiaries share the benefits of ' zero cost ' energy equally.

7.16 The secondary energy is produced when the additional inflows are available which is mostly during the monsoon season. The generating station has to keep all its machines in perfect order to utilise the additional inflows. The thermal generating stations can be taken out for planned maintenance during the monsoon season. However, no hydro generating station is allowed any planned shut down during the monsoon, to ensure proper utilisation of the available water for generation of electricity and to prevent its spillage. From the available generation data of six NHPC generating stations for the past 10 years we have noted that the secondary energy is not always available from all the generating stations, except Chamera Hydroelectric Generating Station. Thus, the revenue earned from the secondary energy is not of permanent nature.

7.17 We are of the view that the secondary energy should be priced at a rate which is beneficial to the generating stations and is also affordable by the beneficiaries. Neither the generating company nor the beneficiaries want that the 'zero cost' energy on account of additional inflows of water be allowed to be wasted. Moreover, the energy generated during the monsoon or the lean inflow periods, is billed at the primary energy rate because the actual quantum of secondary energy generated during any particular year, is known at the end of year only. During any period of time, the beneficiary is not aware whether it is drawing the primary energy or the secondary energy. Therefore, it is not logical to have different rates for the primary energy and the secondary energy. This also avoids adjustments in bills of the beneficiaries at the end of year required in case the secondary energy is charged at a different rate.

7.18 After careful consideration of issues highlighted both by the hydro generating companies as well as the beneficiaries, we are of the considered view that in order to encourage future hydro power development in the private sector, the secondary energy should be priced at the same rate as applicable to the primary energy.

7.19 Thus, we direct that for the next tariff period, the rate of secondary energy shall be equal to that of primary energy.

# CHAPTER 8

# MISCELLANEOUS

## Incentive/disincentive

## THERMAL POWER GENERATING STATIONS

### Existing provisions

8.1 Under the terms and conditions presently applicable, full fixed charges are recoverable at a target availability of 72% for NLC TPS-II, Stage I & II generating stations and of 80% in all other thermal power generating stations. The recovery of capacity (fixed) charges below the level of target availability is allowed on *pro rata* basis. At zero availability, no capacity charges are payable. The generating companies become entitled to incentive at PLF above 72% for NLC TPS-II, Stage I & II generating stations and at PLF above 77% in all other thermal power generating stations. The incentive is allowed to be recovered @ 50% of the fixed cost/kWh at the normative PLF for generation between the normative PLF and up to PLF of 90%, subject to a ceiling of 21.5 paise/kWh. For generation beyond 90% PLF, incentive is allowed to be recovered @ 50% of the incentive payable at 90% PLF.

### Views of the Stakeholders

8.2 The stake holders have given divergent views. These are summarised below:

(a) DVC has suggested to de-link incentive from the fixed cost and revert to a rate of 1 paisa/kWh for every 1% increase over benchmarked PLF of 68.49% and up to 90% PLF. Above 90% PLF rate should be 50%.

(b) NTPC, PGCIL and NEEPCO have suggested that the incentive should be related to availability. According to PGCIL, PLF, for the purpose of claiming incentive, has no relevance under ABT regime. Further, NTPC has sought fixing of incentive rate based on sharing of fixed charges equally between the generating company and the beneficiaries. Alternatively, they have sought incentive/disincentive could be 30 to 40 paise/kWh.

(c) NLC has sought incentive @ 50% of the fixed charges/kWh, without any ceiling for generation beyond a target PLF of 67%.

(d) NEEPCO has sought to de-link incentive from capital cost and has favoured incentive at the flat rate. NEEPCO has suggested a target availability/target PLF of 70% for the purpose of disincentive/incentive. Most of the beneficiaries have asked for a higher target availability/target PLF of 85% for disincentive/incentive.

(e) IPPs like Gujarat Paguthan Energy Corporation Pvt. Ltd. has sought target availability/target PLF of 70% for recovery of full fixed charges and payment of incentive. It is urged that the incentive should be paid as an additional return on equity as provided by Ministry of Power notification dated 30.3.1992 and de-linking it from the fixed cost.

(f) BSES has sought linking of incentive to availability. According to them linking incentive to PLF there is no reward for keeping the availability of generating station high. With regard to rate of incentive/disincentive, it is contended that the basic premise should be that incentive/disincentive should match each other.

(g) Shri KP Rao, an eminent expert on the subject has opined that incentive could be linked with additional return on equity . CII has suggested that the rate of incentive and disincentive should be on equitable basis and that the utilities should be allowed to recover the loss by improving the performance in the subsequent years, if unable to recover full fixed charges due to non-achievement of normative availability level in a particular year.

(h) Bharat Chamber of Commerce has sought to increase the levels of target availability and target PLF from the present ones. They have also suggested that the rate of incentive needs to be objectively fixed so that it does not discourage the beneficiaries to draw additional power on commercial consideration.

(i) IDFC has sought to provide a cap on incentive incorporating relatively lenient performance parameters. According to them, the lenient performance parameters, though having the potential of marginal impact on tariffs in the short-run, will provide sufficient price signals for additional investment in generating capacity.

(j) ADB has suggested that incentive should be linked not to the input but to the power output – its amount and quality.

(k) Shri M. Sahoo, JS & FA, MOP has suggested that incentive should be considered only for generating additional energy during peak hours.

8.3 We have carefully considered the views of the stakeholders. The following specific issues emerge for our consideration and decision: -

(a) Performance measure of incentive, that is, linking of incentive to target PLF or target availability.

(b) Threshold level of target availability or PLF for entitlement to incentive or liability for disincentive.

(c) Linking of incentive and disincentive rate to fixed cost, flat rate or any other factor.

(d) Whether incentive/disincentive should be on equitable basis.

**Performance Measure for Incentive**

8.4 This question was debated by the Commission in its order dated 4.1.2000 in petition No 2/1999. After considering different aspects of the matter, the Commission concluded that the payment of incentive cannot be related to mere availability of the generating station and that the incentive should be earned through actual performance. The relevant part of the order is extracted below:

*"A generator cannot be rewarded for merely putting up a generating unit. It is necessary for him to make it available for the beneficiaries to a reasonable extent so that the latter could draw upon that capacity. Any shortfall in available capacity needs to be commercially punished with the denial of fixed cost. Incentive however, stands on a different footing. In regulated tariffs, it is necessary to keep a provision to reward better performance in order to promote efficiency and economy through cost reduction. Such a reward linked to a demonstrably efficient performance level, should be as challenging as possible. Mere availability does not reflect efficiency. At the same time, in order to keep the machine available without break down, the disincentive of denial of fixed charges is adequate enough. What is also required is that the available capacity should also be efficiently used. For this purpose, the entrepreneur generator should demonstrate*

*that his product is competitive enough both in terms of cost and reliability of service so that additional demand would get generated and he will be able to improve his generating station load factor. Any improvement in the generating station load factor (up to sustainable level) indicates efficient performance, for which reward in the form of incentive is appropriate. Mere availability of the generating station without demand cannot justify incentive payment. This conclusion is inevitable from studying the situation in the eastern region. There, though the generator is available, due to lack of demand, he has to back down. In this process, the generator could claim incentive based on mere availability, which is patently unfair to the consumers who are already meeting the full fixed cost. The Commission considers that with the separation of fixed cost from the variable cost, the beneficiaries are bound to view the cost advantage while making their scheduling. Combined with a little more aggressive marketing effort by the generators, it should be possible to create demand for evacuation of power from surplus areas, which is otherwise bottled up. With this situation, the output and consequently the PLF of generating units is bound to go up. Any incentive which is linked to PLF therefore would be an appropriate reward for cost control through better management of resources and better marketing efforts. There could be other and more effective ways which the Commission will be considering. But, for the present, and in view of the foregoing argument, the Commission considers it appropriate that any scheme of incentive should be linked to actual performance, i.e., generating station load factor instead of mere availability, though the recovery of fixed charges could be still linked to availability".*

8.5 We do not find any justification to deviate from the views earlier recorded by the Commission. We, therefore, hold that performance measure should continue to be based on actual plant load factor and not the availability. The recovery of full fixed charges shall continue to be linked to the target availability as before. However, in so far as generating stations subjected to UI scheme under ABT are concerned, the performance measure shall be the plant load factor based on the scheduled generation given by the Regional Load Despatch Centre and not the actual generation. This is because deviations from schedule are charged differently under UI scheme, incentivising or penalizing the generator, depending upon the grid frequency.

**Threshold Level to qualify for incentive or inviting penalty**

8.6 The Commission in its order dated 15.12.2000 in review petition No 13/2000 had expressed a view to set the target PLF for payment of incentive at a level lower than the target availability of 80% by 3% on account of deemed generation, that is, backing down as ordered by the Regional Load Despatch Centres because of system constraints. However, in case of NLC the levels of target availability as well as PLF were kept at 72%. On fresh consideration of the matter, we are now of the view that incentive should be payable for the performance above the normal performance level. Since the generating station is under an obligation to perform up to the level of target availability, we feel that the incentive should be payable at a target PLF equal to target availability or higher than the target availability. The performance level in terms of actual PLF of NTPC for coal-based generating stations is more than 80% up to March 2003. Therefore, for the present, we consider it appropriate to continue with the target availability of 80% for the recovery of full fixed charges and revise the target PLF level from 77% to 80% for payment of incentive for the thermal power generating stations, other than those belonging to NLC, TPS-II, Stage I & II. NLC was earlier given a target PLF of 72% corresponding to the target availability of 72% specified by the Commission on the ground of the availability of the lignite and we feel that the same should continue for the next tariff period. The recovery of fixed charges for availability less than the target availability shall continue to be on pro-rata basis. At zero availability there would be no recovery of fixed charges.

**Declared Capacity & Availability**

8.7 In the present CERC notification dated 26.3.2001 at clause 2.1, the Declared Capacity for thermal power generating station is defined as the ex-bus capability in MWh and it is stated in the explanation that this shall not exceed the Installed Capacity (IC). The views of the stakeholders on the matter have been summarised below:

(a) NLC, PGCIL and NTPC have sought for the deletion of the above explanation. PGCIL has sought to revise the definition of declared capacity as the capability of a generating station to deliver ex-bus in MW terms rather than in MWh.

(b) TNEB, KSEB etc. have objected to recovery of energy charge for excess scheduled generation which may arise when generator is given scheduled generation (ex-bus) above the generation (ex-bus) corresponding to installed capacity minus normative auxiliary energy consumption when allowed to declare without any restriction.

8.8 The Regional Load Despatch Centres are interpreting the above explanation that the generator can not be allowed to declare its maximum declared capacity more than the sent-out capability arrived at after deducting the normative auxiliary consumption from generation capability at the generator terminals. Since the actual auxiliary consumption varies and it is generally lower than the normative at higher PLFs, the generating station can deliver more power than the sent-out capability corresponding to IC arrived at after deducting normative auxiliary consumption, particularly under favorable ambient and system conditions. However, as per the present practice, this cannot be declared and dispatched. The Commission is therefore, of the view that the generator should have liberty to declare ex-bus capacity without any restriction so that full available capacity could be declared by the generator which would be beneficial to both generator as well as beneficiaries. As such, above explanation from the definition of the Declared Capacity shall be deleted.

8.9 Further, under the ABT scheme, a generator gets the energy charges based on the scheduled generation (ex-bus) given by the respective Regional Load Despatch Centre. For any unscheduled interchange the generator gets/pays UI charges, depending upon the frequency of the grid in a particular time block. Since the rate of energy charges corresponds to per kWh sent out after taking into account the normative auxiliary energy consumption, the full cost of generation gets paid at scheduled generation (ex-bus) corresponding to installed capacity minus normative auxiliary energy consumption. For any scheduled generation (ex-bus) above the generation (ex-bus) corresponding to installed capacity minus normative auxiliary energy consumption, there would be recovery of energy charge in excess of cost of generation. The Commission has found that such excess over the cost of generation was being paid by the beneficiaries in the existing system but without any benefit of additional available generation. The Commission is more concerned here to have the additional capacity available to the grid and would not like to discourage the generator in making available this capacity by putting any restriction.

8.10 In case of hydro power generating stations, declared capacity (clause 3.1 of the notification dated 26.3.2001) has been stated in MW. In actual practice, declaration/scheduling is being done on ex-bus MW basis in a particular time block. As such, definition of Declared Capacity for thermal power generating stations should also be in MW term instead of MWh. In case of gas/liquid fuel based stations, capacity on gas and liquid fuel shall continue be declared separately as at present.

8.11 Having regard to the conclusion reached by us in the above paragraphs, the definition and formula for the computation of availability of coal/lignite or gas. liquid fuel based thermal generating units/stations would be as under:

> **'Availability'** in relation to a thermal generating station for any period means the percentage ratio of sum of average declared capacities (DCs) for all the time blocks during that period and the rated installed capacity of the generating station in accordance with the following formula:
>
> $$\textbf{Availability} = \left\{\left(\sum_{i=1}^{n} DC_i\right) + CL\right\} \times 100 / n \times \left\{IC\left(1 - AUX_n/100\right)\right\}$$
>
> where,
>
> IC = Installed Capacity of the generating station in MW
>
> $DC_i$ = Average declared capacity of the $i^{th}$ time block of the period.
>
> n = Number of time blocks during the period
>
> $AUX_n$ = Normative Auxiliary Energy Consumption as a percentage of gross generation.
>
> CL = Gross MW of capacity of unit(s) kept closed on account of Generation scheduling order.
>
> **Explanation**:
>
> The availability in any period shall be limited to 100% if it works out more than 100% based on the above formula for the purpose of payment of fixed charges.

**Incentive Rate**

8.12 The Commission in its order dated 21.12.2000 had preferred incentive as percentage of fixed cost per kWh instead of as percentage of equity, preferring avoided cost, which accrues to the state level beneficiaries and sharing this avoided cost between the utility and beneficiaries. In order to avoid tariff jolt to the beneficiaries, the Commission had fixed recovery of 50% of the fixed cost per kWh as incentive of generation beyond 77% PLF with a cap rate of 21.5 paise/ kWh. The Commission had observed that this would ensure that the fixed cost is shared between utility and the beneficiaries. Such an arrangement would be equitable for both, the generating companies and the beneficiaries. In this process, the incentive for older generating stations would be protected if not enhanced but the beneficiaries of the new generating stations could not be saddled with heavy burden. In order to avoid flogging of equipment to maximise the revenue, the Commission had reduced the rate of incentive beyond 90% PLF by 50%.

8.13 Some of the parties like NTPC, PGCIL, BSES and CII have argued that incentive and disincentive should be equitable, perhaps meaning that rates for incentive and disincentive should be in the same proportion. We are unable to accept this argument. In our opinion generating company is obligated to perform up to the normal performance level and in case of failure in the discharge of this obligation, the generating company should be faced with a heavy penalty. On the contrary, this cannot be true in the case of incentive because the incentive should be payable for performance above the normal performance level.

8.14 On the question of reasonable incentive rate, we are of the view that rate should be such that it does not discourage the beneficiaries from buying extra power from the generating company. The Commission is concerned that excess power must be utilized in overall national interest and therefore, its cost should be affordable to the beneficiaries. Since the linking of incentive to the fixed cost leads to lower incentive for the older the generating stations, we feel that it will be more appropriate to fix a flat rate of incentive. The ceiling norm of 21.5 paise/kWh was given by the Commission in year 2001. Considering the fact that the threshold target PLF has been raised from 77% to 80%, and that there has been a general inflation in the economy @ 4%, there is a case for increasing the norm of 21.5 paise/kWh too. We feel that a value of 25 paise/kWh would be a reasonable one without giving undue advantage to beneficiaries or undue disadvantage to them. We, therefore, allow incentive rate of 25 paise/kWh for generation above the target PLF of 80% in case of thermal power generating stations other than TPS-II stage-I and II of NLC. In case of TPS-II stage-I and II stations of NLC, Incentive rate of 25 paise/kWh shall apply for generation above the target PLF of 72%.

## HYDRO POWER GENERATING STATIONS

**Existing provision**

8.15 At present, the incentive for hydro power generating stations is governed by the following formula:

Incentive = (Capacity Charge) X ($CI_A$-$CI_N$ )/100

Where,
Capacity Charge = Annual Fixed Charge – Primary Energy Charge, and
$CI_A$ is the Capacity Index achieved & $CI_N$ the Normative Capacity Index

8.16 Based on the studies made, it has been observed that as the hydro power generating station grows older and loans are paid off, its Annual Fixed Charge goes on decreasing. Further, due to general inflation in the economy, the primary energy charge, which is a function of lowest variable cost of thermal power generating station in the respective region, goes on increasing. In other words, with the passage of time, the value of Capacity Charge for any station would go on decreasing. Thus, for the same level of performance of a hydro power generating station, the incentive payable to the generator goes on decreasing year to year. It is envisaged that during the next tariff period, the primary energy charge (worked out on the basis of 90% of the lowest variable cost of the central sector thermal power generating station of the region) could even exceed the Annual Fixed Charge of some old hydro power generating stations like Salal, Loktak and Baira siul . In such a scenario, there would be very low or NIL incentive for the hydro generating company to run its old generating stations efficiently, even though their performance (based on capacity index achieved) is comparable with the new generating stations.

8.17 Projections indicate that during the next tariff period commencing from 1.4.2004, the incentive earned by Salal and Baira Siul would be Zero due to decreasing values of AFC and increasing amounts of primary energy charge. To us, this seems to be unfair since according to us the quantum of incentive earned should remain same for the same level of performance , irrespective of passage of time.

8.18 In the Discussion Paper it was suggested that in case of hydro power generation, incentive could be linked with the annual peak time generation and a suitable incentive rate be fixed for the same. This would substitute the capacity charge component as applicable in the present formula for incentive. The proposed incentive formula suggested in the Discussion Paper is :

Incentive = Actual Peak Time Generation x Incentive Rate x $(CI_A-CI_N)/100$

**Views of the stake holders**

8.19 Based on the written submissions made and also views expressed at the hearings on Terms and conditions of Tariff, comments of different stakeholders have been summarized as below:

(a) DVC has proposed to continue with the existing incentive formula of the Commission notification dated 26 March, 2001.

(b) NHPC has stated that the proposed formula should be made applicable to the storage type of peaking generating stations and for the ROR generating stations, the existing incentive formula should continue. NHPC has also stated that having the factor of actual Capacity Index along with actual peak time generation in the proposed formula does not seem to be justified.

(c) NEEPCO has proposed that the incentive based on actual peak generation may be considered.

(d) West Bengal State Electricity Board has stated that the formula proposed in the discussion paper needs further examination.

(e) KPCL concurs with the view of NHPC for providing incentive for generation during peak hours in addition to the incentive on account of higher capacity index and secondary energy already applicable.

(f) ASEB has stated that incentive may be considered at 0.5% of the capacity charge payable to the generator for each percent rise in capacity index beyond the normative value of 85%.

(g) PSEB has proposed flat rate incentive as in case of thermal power generating stations.

(h) HPSEB has stated that methodology for incentive for generation during peak hours shall provide necessary encouragement for the future development of peaking hydro power generating stations with consequent improvement in hydro-thermal mix.

(i) RVPNL has apprehensions that new incentive formula would increase the incentive being paid currently to NHPC.

(j) HPERC agrees with the formula proposed in the Discussion Paper. However, they have proposed to put a cap to the limit of incentive payable to generator if it is decided to continue with the existing provisions of secondary energy rate being equal to that of primary energy.

(k) Bengal National Chamber of Commerce and Utkal Chamber of Commerce have suggested that there should be incentive for generating more hydro power during peak load hours.

(l) PTC has suggested different methodology by splitting design energy into peak design energy and off-peak design energy and giving differential peak and off peak rates. By adopting this concept there is no need to give incentive for CI higher than 85%.

8.20 Based on the above comments of stakeholders, we have observed that not much favorable response has been received on the incentive formula suggested in the Discussion Paper. Moreover, the peak generation also has certain component of secondary energy, which is difficult to quantify, and there would be double counting of such energy. Thus the methodology suggested in the Discussion Paper is not being pursued.

8.21 Keeping in view the vast hydro potential which the country has still to tap, we feel that there should be sufficient performance based incentive to a hydro generator so as to attract private sector participation in the hydro sector.

8.22 A new methodology to incentivise the hydro power generation so as to overcome the shortcomings of present incentive formula has been suggested by the staff of the Commission and presentation for the same was made at the open hearing. The proposed formula is:

**Incentive = F x (Annual Fixed Charges) X ($CI_A$-$CI_N$ )/100**

Where ,
$CI_A$ = Capacity Index achieved & $CI_N$= Normative Capacity Index, and
'F' is a constant relating to Annual Fixed Charges (AFC) of the generating station.

8.23 Linking incentive with 'AFC' instead of 'Capacity Charge' will overcome the negative value of the Capacity Charge as a result of loans being paid off and generating station growing older. The Commission is conscious of the fact that the incentive formula proposed above has also limitation in the sense that initially for new station, the incentive would be reducing due to reduction in the value of Annual Fixed Charges. However, the same shall stabilise after a few years and the problem of old stations getting virtually no incentive in spite of good performance shall be mitigated to a great extent.

8.24 Since our approach is not to disturb the existing level of incentive earned by the hydro power generating companies, studies have been carried out to work out the factor 'F' relating to AFC which would provide the same level of incentive to the generator as it would have attained during the year 2004-05 with the prevalent values of AFC, primary energy rate and normative value of capacity index. It has been observed that for factor F= 0.65 i.e. considering AFC = 65%, the incentive to be earned by the generator in the first year of next tariff period would be of the same order as it would have earned with the old formula.

8.25 We have noted from the results of analysis that with the new methodology of calculating the incentive, the amount of incentive to be earned by the old hydro power generating stations would never be zero.

8.26 The modified incentive formula applicable during the next tariff period shall be as under :

Incentive = 0.65 x (Annual Fixed Charges)x ($CI_A$-$CI_N$ )/ 100

$CI_A$ = Capacity Index achieved & $CI_N$= Normative Capacity Index

Note :

In case the generating company fails to achieve the normative Capacity Index during the year, it shall earn disincentive proportional to the Annual Fixed Charges on pro-rata basis.

**Incentive for timely completion of hydro projects**

8.27 During scrutiny of tariff proposals of various hydro projects in the Commission, it has been observed that most of the hydro projects are encountering time and cost over run problem during execution of the project.

8.28 Major reasons resulting in the time and cost over run of hydro projects have been identified as follows :

(a) Land acquisition;
(b) Funds constraints;
(c) Technical/design problems;
(d) Geological surprises;
(e) Natural calamities;
(f) Delay in finalising & evaluation of tenders; and
(g) Law & order/ Militancy related problems.

8.29 Of the various reasons stated above, natural calamities (like flood and land slides) and geological surprises only appear to genuine reasons for time and cost over run of the project, which are beyond the control of the executing agencies. Cost over run on account of other factors appears to be totally due to administrative inefficiencies and improper monitoring on the part of the executing agency.

8.30 Table below shows the extent of cost over run of some of the projects executed by NHPC and NEEPCO:

**Table- 8.1**

| HE Project | State- Ownership | Original Apprd. Cost (Rs. Crs) | Completion cost (Rs. Crs) | % cost over run |
|---|---|---|---|---|
| 1. Rangit | Sikkim, NHPC | 137.61- Oct., 88 | 492.26- Dec,99 | 358 |
| 2. Ranganadi | Ar. Pr., NEEPCO | 276.40- Dec, 84 | 1455.45 - July, 99 | 526 |
| 3. Doyang | Nagaland, NEEPCO | 166.66- July, 89 | 758.70- July, 00 | 455 |
| 4. Nathpa Jhakri | H.P., SJVNL | 1678.02-Apr, 89 | 8500-Aug 04 | 506 |

8.31 Apart from above, Tehri- 1000 MW,THDC and Dulhasti- 390 MW, NHPC are likely to be commissioned during the year 2004-05. These projects would also have substantial time and cost over run.

8.32 Cost of generation from these projects being very high (Doyang and Rangit) , the beneficiaries have refused to buy power thereby creating conditions of uncertainty on utilisation of power of these projects.

8.33 Keeping in view the vast hydro potential which the country has still to tap, and its peaking benefits to the system, we feel that there should be incentive to a hydro generating company on early commissioning of the new hydro power generating station and at the same time it should be penalised in the event of time and cost overrun of the project. We have proposed following scheme of incentive/disincentive for a new hydro power generating station.

8.34 In case of commissioning of a hydro power generating station or part thereof ahead of schedule, as set out in the first approval of the Central Government or techno-economic clearance of the Authority, as applicable, the generating station shall become eligible for incentive for an amount equal to pro-rata reduction in Interest During Construction, achieved on commissioning ahead of the schedule. The incentive shall be recovered through tariff in twelve equal monthly installments during the first year of operation of the generating station. In case of delay in commissioning as set out in the first approval of the Central Government or techno-economic clearance of the Authority, as applicable, Interest During Construction for the period of delay shall not be allowed to be capitalised for the purpose of tariff, unless the delay is on account of circumstances beyond the control of the utility.

**INTER-STATE TRANSMISSION**

**Existing Provision**

8.35 The present notification stipulates a slab system for availability-based incentive. The incentive is 1% of the equity for every 0.5% rise in the availability above 98%, except for the target availability in the range of 99.51 to 99.75% for which incentive @1% of equity has been allowed.

**Views of stakeholders**

8.36 Most of the stake holders have linked their observation on the incentives with the target availability and these observations have already been deliberated while discussing the issue of target availability.

8.37 In so far as suggestion of GRIDCO, BSEB and RERC to link incentives/disincentives with transmission loss is concerned, we are of the opinion that the losses in the transmission system depend mainly on the extent of line loadings and flow of reactive power. Line loading can be controlled only by way of expansion of the system. In the present era of resource constraint and augmentation based on planning process, the transmission service provider can hardly do anything to relieve loading. As far as reactive flows are concerned, the Commission has already approved a pricing scheme for reactive energy based on voltage conditions at inter-state points. In view of the above we do not find any merit in the suggestion for fixing a norm for transmission losses.

8.38 We have carefully considered views expressed by the parties. We are fully convinced about need for incentive in the transmission sector based on availability. In our opinion, availability of transmission corridor is as critical, if not more critical than availability of generating capacity. We believe that incentive scheme acts as catalyst for- (a) preventive maintenance so that breakdowns/faults are minimised and (b) urgent repairs whenever breakdowns/faults occur. In the absence of adequate availability of transmission system, the constituents may not only be deprived of power generated at the generating station but shall have to pay fixed charges for generation, far in excess of the incentive likely to be payable for the transmission system.

## Conclusion

8.39 The existing system of incentives linked with availability of transmission system has worked well and hence we direct that the incentive shall be continued to be regulated in accordance with the current rates, which are given in the table below:

**Table- 8.2**

| Availability % | Incentive as a percent of equity | Cumulative Incentive As a percent of equity |
|---|---|---|
| 98% and below | 0.00 | 0.00 |
| 98.01% -98.50% | 1.00 | 1.00 |
| 98.51% - 99.00% | 1.00 | 2.00 |
| 99.01% - 99.50% | 1.00 | 3.00 |
| 99.51 –99.75% | 1.00 | 4.00 |

## Development Surcharge

8.40 The Commission while specifying the terms and conditions of tariff for the period commencing on 1.4.2001 had introduced the concept of Development Surcharge. The aim for levying the Development Surcharge was to provide additional cash flow for the purpose of capacity addition in generation and transmission of electricity. During the current tariff period, the Development Surcharge is prescribed @ 5% of the capacity (fixed) charges for thermal power generating stations, 5% of both capacity charges and primary energy charges for hydro power generating stations and 10% of the total transmission charges in case of the inter-state transmission system. The Commission had also laid down the guidelines for utilisation of the Development Surcharge. The Commission had advised the Central Government to exempt the Development Surcharge from payment of income-tax. The Central Government has not yet issued any order on exemption of the Development Surcharge from the income-tax. It has been stated that some of the utilities are not collecting the Development Surcharge from the beneficiaries.

8.41 The Commission in its order dated 21.12.2000 expressly observed that it was not its intention to provide for all the funds for capacity addition through the tariff. The utilities should be able to generate resources for ploughing back into the business for capacity addition out of the return on equity with the additional advantage of pass-through of the income-tax. Further, the Central Government as the sole owner of the companies involved in power sector should also subscribe to the equity of these companies within its budgetary resources.

8.42 The responses to the Discussion Paper on this issue reveal that the central utilities have favoured its retention, while seeking relaxing of the terms for utilisation stipulated in the Commission's order dated 21.12.2000. It is suggested that the Development Surcharge be exempted from income-tax. It is also suggested that the Development Surcharge collected should be utilised only for development of hydro sector for achieving the optimum hydro-thermal mix. The State Electricity Boards and their successor entities do not favour the continuation of the Development Surcharge and have sought its abolition on the grounds that its levy is not authorised by law and no corresponding benefit accrues to them. They have argued that the central generating and transmission utilities are earning reasonable return as well as incentive, which could be utilised for capacity additions in generation as well as transmission. It is urged that In the regime of declining interest rates, there is no need to block the funds collected as Development Surcharge. The collection of the Development Surcharge has been sought to be discontinued for social, political and economic reasons as well, particularly in the context of liberalisation of electricity sector with the enactment of the Act as a consequence of which the sector has been opened up for private participation. Some of the stakeholders opposed to levy of the Development Surcharge have suggested its continuation subject to reduction of return on equity from the existing level of 16% to 12%.

8.43 The other stakeholders from private sector have suggested that the funds needed for future capacity additions may be allowed through higher rate of depreciation to all the utilities in the electricity sector. They feel that levy of the Development Surcharge is unjustified since it benefits the central power sector utilities and thus tilts the scale in their favour by denying the level playing field to other players in the sector. It is argued that the levy of the Development Surcharge impairs the capacity of the central power sector utilities to impose commercial self-discipline. When all expenditure after the date of commercial operation is borne by the consumers, there is no justification for levying further Development Surcharge on them. Accordingly, they have argued against extension of the concept of the Development Surcharge to IPPs since they are not committed to reinvest their resources in the development of power sector, an essential condition for levy of the Development Surcharge.

8.44 From the above, it can be seen that there is no consensus on this issue among the stakeholders and their opinions vary widely. We have carefully considered the issue in the light of the views expressed by the stakeholders. The country is targeting to add generation capacity of over 1,00,000 MW by 2012 to meet the existing shortages. There should be a matching investment for creating the transmission and distribution facilities for conveyance of electricity generated by capacity additions. The central sector power utilities under the regulatory jurisdiction of the Commission have a significant role to play in the capacity addition programmes of the Central Government. It is not the intention of the Commission to provide for all the investment needs through retained earnings or the Development Surcharge only, as there is always a limit up to which an extension programme can be supported by the existing capacity. The Commission has reduced the return on equity to 14%. Keeping all these factors in view, we feel that the balance of advantage lies in continuing the Development Surcharge levied under the order dated 21.12.2000, which was translated into the notification dated 26.3.2001. The conditions for collection and utilisation of the Development Surcharge will also remain unaltered. As we have noted above, some of the State Electricity Boards or their successor entities have questioned the authority of the Commission to levy the Development Surcharge. We may take note of the fact that some of them, Madhya Pradesh State Electricity Board and Karnataka Power Transmission Corporation Ltd, to quote, have already preferred appeals questioning levy of the Development Surcharge by the Commission in its earlier order and the notification. These appeals are presently pending before the High Court of Delhi. Therefore, without expressing any further views on this issue, we have preferred the *status quo*.

8.45 Akin to the Development Surcharge, the Commission had allowed Transmission Majoration Factor (TMF) in case of transmission licensees through the joint venture route, who obtain license on or before 31.3.2004 and the TMF shall be available to such licensees through out the license period. The Commission maintains status quo on this issue as well. In line with the provision of the Electricity Act, 2003, the Commission would prefer competitive bidding for transmission services as well. In case of competitively bid projects, annual transmission charges shall be the criteria for selection. In view of this and since no other JV is contemplated be PGCIL/CTU, at this stage TMF will not be available to new transmission licensees to whom licenses may be granted on or after 1.4.2004. The Commission also clarifies that wherever TMF is granted the Development Surcharge shall not be payable.

## Unscheduled Interchange (UI) Rate

### Existing provisions

8.46 Unscheduled Interchange Charge (UI Charge) is a distinctive feature of the existing Availability Based Tariff (ABT) scheme. UI charge is linked to grid frequency and is payable or receivable by the utilities depending upon their default of deviating from the generation and drawl schedules. This feature in ABT scheme was introduced to bring about discipline in the system. The existing provisions provides for UI charges for all UI transactions to be based on average frequency of the time block as per the following rates:

| Average Frequency of time block | UI Rate (Paise per KWh) |
| --- | --- |
| 50.5 Hz and above | 0.00 |
| Below 50.5 Hz and up to 50.48 Hz | 5.60 |
| Below 49.04 Hz and up to 49.02 Hz | 414.40 |
| Below 49.02 Hz | 4.20 |
| Between 50.5 Hz and 49.02 Hz | Linear in 0.02 Hz step |

(Each 0.02 Hz step is equivalent to 5.60 paise/kWh within the above range)

8.47 In order to give adequate economic signal during power shortage conditions, the Commission had decided to link UI rate to the costliest form of generation, that is, diesel generation. Accordingly, the Commission in its order dated 4.1.2000 in petition No 2/1999, subsequently transformed into notification dated 26.3.2001 prescribed UI rate of 420.00 paise/kWh in case of overdrawls at a frequency below 49.02 Hz. No UI charge is payable in case of overdrawals at frequency of 50.5 Hz and above.

## View of stakeholders

8.48 The review of UI rates was suggested by PGCIL. We are given to understand that the liquid fuel base generating stations are not getting dispatched due to high fuel cost and the beneficiaries are resorting to overdrawls from the regional grids rather than dispatching the capacity. Against this background, PGCIL has suggested that the maximum UI rate of 420 paise/kWh needs to be revised to 600 paise/kWh. NTPC and Regional Load Despatch Centres have also reported that liquid fuel capacity is not getting dispatched under ABT regime.

## UI Rate

8.49 We are persuaded to accept the view expressed by PGCIL, NTPC and Regional Load Despatch Centres that the present UI rate of 420 paise/kWh is not sending the desired commercial signals of helping the grid under low frequency conditions.

8.50 UI rate of 420 paise/kWh currently prescribed is based on price of electricity from the DG set generating stations prevailing at the time of order dated 4.1.2000. To arrive at UI rate of 420 paise/kWh the fixed cost component was computed at 160 paise/kWh and energy charge component at 267 paise/kWh. The total added up to 427 paise/kWh, which was rounded off to 420 paise/kWh. The energy charge of 267 paise/kWh was based on fuel price of around of Rs.13330/kL. The current price of diesel is of the order of Rs.21000/kL. Therefore, the energy charge now works out to 21000/13330 x 267 = 420.50 paise/kWh and the total revised UI rate would work out to 421 + 160 = 581 paise/ kWh. This can be rounded off to 600 paise/kWh. This is on the assumption that there is no significant change in the fixed cost of DG set generating stations. Therefore, 600 paise/kWh can be adopted as the revised UI rate below 49.02 Hz frequency. The revised UI charge shall be applicable from the date the revised terms and conditions of tariff come into force. The following revised formulation in regard to levy of UI charge may be considered for the purpose of notification:

**<u>"Unscheduled Interchange (UI) charges applicable to generating stations covered under ABT</u>**

(a) Variation in actual generation or actual drawl and scheduled generation or scheduled drawl shall be accounted for through Unscheduled Interchange (UI) Charges. UI for the generating station shall be equal to its actual generation minus its scheduled generation. UI for the beneficiary shall be equal to its total actual drawl minus its total scheduled drawl. UI shall be worked out for each 15-minute time block. Charges for all UI transactions shall be based on average frequency of the time block and the following rates shall apply:

| Average Frequency of time block | UI Rate (Paise per KWh) |
|---|---|
| 50.5 Hz and above | 0.00 |
| Below 50.5 Hz and up to 50.48 Hz | 8.00 |
| Below 49.04 Hz and up to 49.02 Hz | 592.00 |
| Below 49.02 Hz | 600.00 |
| Between 50.5 Hz and 49.02 Hz | Linear in 0.02 Hz step |

(Each 0.02 Hz step is equivalent to 8.0 paise/kWh within the above range)

(b) in case it is observed that the declaration of its capability by the generating station is on lower side and the actual generation is more than the declared capacity, then UI charge due to the generating station on account of such extra generation shall be reduced to zero and the amount shall be credited towards UI account of the beneficiaries in the ratio of their capacity share in the generating station."

## Rebate and Late Payment Surcharge

8.51 The present tariff mechanism provides for rebate of 2.5 % for payment against the Letter of Credit and 1 % rebate for payment within 30 days. The generating companies have argued that in the falling interest rate regime, there is need to review the rebate presently prescribed. On careful consideration of the matter, we direct that the rebate @ 2 % for payment against Letter of Credit and 1 % for payment within 30 days should be adequate.

8.52 Late payment surcharge carries the rate of 1.5 % p.m. at present. The beneficiaries have argued in favour of reducing the late payment surcharge in view of falling interest rates. No doubt, there is decline in the interest rates. However, the Commission recognises the transaction to be complete when the bill is paid for by the beneficiaries for the energy supplied or transmitted. We, therefore, prefer early settlement of the dues of the generating and the transmission utilities as non-payment or late payment of bills results in accumulation of huge arrears, which adversely affects the health of the State Electricity Boards as well as the generating and transmission utilities. We, therefore, are of the considered view that delay in payment deserves to be discouraged. On this view, there is a case to increase rate of late payment surcharge instead of reducing it. On the overall consideration of the matter, we are opting in favour of *status quo*. In our considered view, this should not be the cause for heart burning because the provision of late payment surcharge is invoked only when a beneficiary has defaulted in making timely payment of dues of the generating company or the transmission utility.

## Treatment of Income-tax

8.53 At present return on equity is on post-tax basis. Tax is treated as an expense at actuals and is reimbursed by the beneficiaries. In this context, we would like to compare the provision on treatment of income-tax contained in the notification dated 30.3.1992 of the Central Government vis-à-vis the practice being followed by the central power sector utilities. The notification dated 30.3.1992 contemplates computation of annual fixed charges with an element towards income-tax. The tax element, according to this notification, should be computed as per actuals on 16% return on equity and extra liability on account of FERV in computing the return on equity not exceeding 16 % in the currency of the subscribed capital with the provision for adjustment of any under or over-recovery every year. In this case, when tax is reimbursed, it is treated as an income in the hands of the generating company and it is taxed again. This process is called the grossing up of tax. NTPC instead of doing the grossing up, is billing the actual tax to the parties as tariff. The merit of this alternative is that benefit of tax holiday and other fiscal concessions get passed on to the beneficiaries. Thus, in the existing system adopted by the central power sector utilities, the beneficiaries are *de facto* assessees. In case pre-tax return is given, the fiscal incentives, which are available otherwise, would not be available to the beneficiaries. The rate for grossing up the returns is another issue which needs to be discussed. The utilities shall, however, have the benefit of optimising the taxes.

8.54 Having taken a view on adoption of the return on equity approach in the earlier part of this Order, we would restrict our arguments with regard to pre- tax or post-tax returns only on return on equity. Before expressing any view in the matter, we would like to deal with the comments received from various stakeholders in this regard.

8.55 NTPC suggested a pre-tax return by increasing the ROCE by about 1.7 % instead of 0.5 % suggested in the Discussion Paper. NLC preferred a post-tax return on equity. NHPC observed that 0.5 % mark-up proposed in the Discussion Paper to cover the cost of FERV, income tax, etc., is on *ad hoc* basis and not based on any studies and, therefore, should be properly evaluated. POWERGRID suggested continuation of the existing method of income-tax as a pass through. The majority of the stakeholders and experts argued that the income-tax should be paid by the person who earns an income and accordingly, it should not be passed on to the beneficiaries.

8.56 We have applied our mind on the issue of income-tax pass through in the tariff. Income tax is subject to many concessions, tax-holiday, etc. based on which pass through mechanism was decided. Incidence of income-tax is a recent phenomenon and with addition to capacity the tax liability may come down due to concessions, depreciation, etc. In view of this, we order to continue with income-tax pass through mechanism for the next tariff period commencing from 1.4.2004. Pass through of income-tax may be reviewed as and when the concept of return on capital employed is considered and adopted. The Commission is in favour of a pre-tax return in principle in order to incentivise the utilities on tax planning. However, since ROCE model is not being adopted for the present, instead of grossing up the tax, income-tax pass through method, being simpler can be continued.

8.57 The present system of sharing of income tax by various beneficiaries shall continue as per the procedure contained in the Commission's notification dated 26.3.2001.

## Promoting Investments

8.58 The Commission is mandated by Section 61 of the Act to specify terms and conditions of tariff. While doing so one of the guiding principles is the promotion of optimum investment in the power sector. The Commission is acutely aware of prevailing peak and energy shortages, generation/transmission capacity constraints. Slow pace of extension of electric supply to un-electrified villages/hamlets continues to be a serious concern. Investments in sub- transmission and distribution to improve quantity and quality of supply needs no emphasis. It has been primarily the area of sub-transmission and distribution where the sector has not been able to generate enough resources for meeting the investment needs. The opening up of the sector in 90's for private investment was encouraging but the euphoria could not be sustained as a large number IPPs did not achieve financial closure. Shifting the emphasis of investment from generation to sub transmission and distribution over last few years is a movement in the right direction. Large investments made and committed for future under APDRP have started showing results with distribution business nearly succeeding in making all current payments to CPSUs barring some exceptions. Having said this, the Commission is also aware that only simultaneous quick addition in generation and transmission (while distribution reforms are being implemented) capacities can take the country out of power shortages and promote genuine competition in the power sector. Government of India has mandated the CPSUs to continue the capacity addition more aggressively in the 10$^{th}$ and 11$^{th}$ Five Year Plans. The Commission has maintained attractive return on equity primarily for promotion of investment. The provision made by the Commission to allow loan repayment through advance against depreciation for 10-year loan as against 12 years earlier is also a step on the same direction. Moving towards light-handed regulation based on normative parameters should generate added confidence among the investors. These steps coupled with the provision of open access and trading should send right signal for attracting private investment.

8.59 Further, the Commission is mandated under Section 79(2)(iii) of the Act to advise the Central Government in the matter of promotion of investment in power sector. We would like to suggest the following for consideration of the Central Government:

(a) Sustained emphasis on distribution reforms and promotion of investment in distribution by way of strict monitoring of APDRP fund utilisation and consequential benefits.

(b) Announcement of policies regarding rural electrification and rural distribution in consultation with States, so as to make distribution in rural areas a viable proposition.

(c) The stakeholders, especially IPPs who appeared before us, have made in their written pleadings and expressed their views that the Indian Financial Institutions ask for a minimum of 30% equity for grant of loans. The Government could consider issuing a directive to the AIFIs to accept equity investment of 20% for lending to power projects. The need for doing the projects purely on non-recourse financial, especially by the Indian companies has not proved to be a viable option and if the projects are executed on the strength of the Balance Sheet of the promoters they could obtain loans at more competitive rates.

(d) The different industries are competing for raising all loans from the same source and there are sectoral allocations by the lenders as well. It will be worthwhile considering increasing the sectoral allocations to power sector so that the targeted capacity allocations could be achieved.

(e) Monitoring of time and cost over runs in the Government funded projects more effectively, particularly in respect of Hydro projects, is considered essential.

(f) The Commission also recognises that the fuel charge in the cost of thermal power generating station is in the range of 60% to 70%. The fuel sector is totally unregulated and is in the hands of the Government. Whatever efforts are taken by the regulators to promote efficiency, economy and competition, the results cannot be felt in view of the increasing fuel prices, and it is a major part in the total cost of generation. The inefficiencies of other sectors should not, therefore, be passed on to the power sector. We have been hearing about setting up of regulators for other areas of Energy as well. This needs to be expedited so that inputs to the power sector are also procured from efficient sources.

## Payment of Capacity charges

**THERMAL POWER GENERATING STATIONS**

8.60 Billing and payment of capacity charges shall be done on a monthly basis in the following manner:

(a) Each beneficiary shall pay the capacity charges in proportion to its percentage share in Installed Capacity of the generating station.

**Note 1**

Allocation of total capacity of central sector generating stations is made by Central Government from time to time which also has an unallocated portion. Allocation of the unallocated portion shall be made by the Central Government from time to time, for the total unallocated capacity. The total capacity share of any beneficiaries would be sum of its capacity share plus allocation out of the unallocated portion. In case of no specific distribution of unallocated power by the Central Government, the unallocated power shall be added to the allocated shares in the same proportion as the allocated shares.

**Note 2**

The beneficiaries may propose surrendering part of their allocated share to other States within/outside the region. In such cases, depending upon the technical feasibility of power transfer and specific agreements reached by the generating company with other States within/outside the region for such transfers, the shares of beneficiaries may be re-allocated by the Central Government for a specific period. When such re-allocations are made, the beneficiaries who surrender the share shall not be liable to pay capacity charges for the surrendered share. The capacity charges for the capacity surrendered and reallocated as above shall be paid by the State(s) to whom the surrendered capacity is allocated. Except for the period of reallocation of capacity as above, the beneficiaries of the generating station shall continue to pay the full fixed charges as per allocated capacity shares.

(b) The beneficiaries shall have full freedom for negotiating any transaction for utilisation of their capacity shares. In such cases, the beneficiary having allocation in the capacity of the generating station shall be liable for full payment of capacity charges and energy charges (including that for sale of power under the transactions negotiated by them) for all its scheduled and unscheduled transactions from its capacity share.

(c) If there is any capacity which remains un-requisitioned during day-to-day operation, Regional Load Despatch Centre shall advise all beneficiaries in the region and the other Regional Load Despatch Centre so that such capacity may be requisitioned through bilateral arrangements with the concerned generating company/beneficiary(ies) under intimation to the Regional Load Despatch Centre.

This information shall also be made available online by Regional Load Despatch Centres through their respective websites.

(d) The capacity charges shall be paid by the beneficiary(ies) including those outside the region to the generating company every month in accordance with the following formulas:

8.61 Total Capacity charges payable to the thermal power generating company for the:

1$^{st}$ month = (1xACC1)/12
2$^{nd}$ month = (2XACC2 - 1XACC1)/12
3$^{rd}$ month = (3xACC3 - 2XACC2)/12
4$^{th}$ month = (4xACC4 - 3xACC3)/12
5$^{th}$ month = (5XACC5 - 4xACC4)/12
6$^{th}$ month = (6XACC5 - 5xACC5)/12
7$^{th}$ month = (7XACC7 - 6xACC6)/12
8$^{th}$ month = (8xACC8 - 7xACC7)/12
9$^{th}$ month = (9xACC9 - 8xACC8)/12
10$^{th}$ month = (10xACC10 – 9xACC9)/12
11$^{th}$ month = (11xACC11 - 10xACC10)/12
12$^{th}$ month = (12xACC12 - 11xACC11)/12

8.62 Each beneficiary having firm allocation in capacity of the generating station shall pay for the :

1$^{st}$ month = [ ACC1 x WB1 ]/1200
2$^{nd}$ month = [2XACC2 x WB2 - 1XACC1x WB1]/1200
3$^{rd}$ month = (3xACC3 x WB3 - 2XACC2 x WB2]/1200
4$^{th}$ month = (4xACC4 x WB4 - 3xACC3 x WB3]/1200

$5^{th}$ month = (5XACC5 x WB5 - 4xACC4 x WB4]/1200
$6^{th}$ month = (6XACC5 x WB6 - 5xACC5 x WB5]/1200
$7^{th}$ month = (7XACC7 x WB7 - 6xACC6 x WB6]/1200
$8^{th}$ month = (8xACC8 x WB8 - 7xACC7 x WB7]/1200
$9^{th}$ month = (9xACC9 x WB9 - 8xACC8 x WB8]/1200
$10^{th}$ month = (10xACC10 x WB10- 9xACC9 x WB9]/1200
$11^{th}$ month = (11xACC11 x WB11- 10xACC10x WB10]/1200
$12^{th}$ month = (12xACC12 x WB12- 11xACC11x WB 11]/1200

Where,
ACC1, ACC2, ACC3, ACC4, ACC5 ACC6, ACC7, ACC8, ACC9, ACC10, ACC11 and ACC12 are the amount of Annual Capacity Charge corresponding to 'Availability' for the cumulative period up to the end of $1^{st}$, $2^{nd}$ $3^{rd}$, $4^{th}$, $5^{th}$, $6^{th}$, $7^{th}$, $8^{th}$, $9^{th}$, $10^{th}$, $11^{th}$ and $12^{th}$ months respectively.

And, WB1, WB2, WB3, WB4, WB5, WB6, WB7, WB8, WB9, WB10, WB11 and WB12 are the weighted average of percentage allocated capacity share of the beneficiary during the cumulative period up to $1^{st}$, $2^{nd}$ $3^{rd}$, $4^{th}$, $5^{th}$, $6^{th}$, $7^{th}$, $8^{th}$, $9^{th}$, $10^{th}$ $11^{th}$ and $12^{th}$ month respectively.

## HYDRO POWER GENERATING STATIONS

### Existing Provision

8.63 Presently the capacity charges are being paid by the beneficiaries in 12 monthly equal installments.

8.64 NHPC in its submission on the Discussion Paper and also at the open hearing had pleaded that monthly capacity charges to be recovered from the beneficiaries should be proportionate to design energy of the particular month and not in 12 monthly equal installments to ensure cash flow commensurate with scheduled energy generation in various months. PSEB representative at the hearing also supported the view of NHPC and agreed that by this method the total charges to the consumers would be based on energy received from the generating station on month-to-month basis, instead of notional monthly charges because the capacity charges are not in proportion to energy.

8.65 Since none of the other beneficiaries has raised any objection to the proposed capacity charges payment mechanism, we agree with the contention of NHPC and allow payment of monthly capacity charges in the ratio of saleable design energy of the particular month. The formula for payment of monthly capacity charges is being modified accordingly as given below:

8.66 The capacity charges shall be paid by the beneficiary(ies) including those outside the region to the generating company every month in accordance with the following formula:

$ACC_1 \quad = AFC - ( SPE_1 + DE_{\text{2nd to 12th months}}) * \text{Primary Energy Rate}$
$ACC_2 \quad = AFC - ( SPE_2 + DE_{\text{3rd to 12th months}}) * \text{Primary Energy Rate}$
$ACC_3 \quad = AFC - ( SPE_3 + DE_{\text{4th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_4 \quad = AFC - ( SPE_4 + DE_{\text{5th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_5 \quad = AFC - ( SPE_5 + DE_{\text{6th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_6 \quad = AFC - ( SPE_6 + DE_{\text{7th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_7 \quad = AFC - ( SPE_7 + DE_{\text{8th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_8 \quad = AFC - ( SPE_8 + DE_{\text{9th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_9 \quad = AFC - ( SPE_9 + DE_{\text{10th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_{10} \quad = AFC - ( SPE_{10} + DE_{\text{11th to 12th months}}) * \text{Primary Energy Rate}$
$ACC_{11} \quad = AFC - ( SPE_{11} + DE_{\text{12th month}}) * \text{Primary Energy Rate}$
$ACC_{12} \quad = (AFC - SPE_{12} ) * \text{Primary Energy Rate}$

Where,

AFC = Annual Fixed Charges

$ACC_1$, $ACC_2$, $ACC_3$, $ACC_4$, $ACC_5$ $ACC_6$, $ACC_7$, $ACC_8$, $ACC_9$, $ACC_{10}$, $ACC_{11}$ and $ACC_{12}$ are the amount of Annual Capacity Charge for the cumulative period up to the end of 1st, 2nd 3rd, 4th, 5th, 6th, 7th, 8th, 9th, 10th, 11th and 12th months respectively.

$SPE_1$, $SPE_2$, $SPE_3$,………………… $SPE_{!2}$ are the Ex-bus scheduled primary energy values up to 1st, 2nd, 3rd ……12th months of the year respectively.

$$CC1 = ACC_1 \times \frac{DE1}{DE}$$

$$CC2 = ACC_2 \times \frac{DE2}{DE}$$

$$CC3 = ACC_3 \times \frac{DE3}{DE}$$

$$CC4 = ACC_4 \times \frac{DE4}{DE}$$

$$CC5 = ACC_5 \times \frac{DE5}{DE}$$

$$CC6 = ACC_6 \times \frac{DE6}{DE}$$

$$CC7 = ACC_7 \times \frac{DE7}{DE}$$

$$CC8 = ACC_8 \times \frac{DE8}{DE}$$

$$CC9 = ACC_9 \times \frac{DE9}{DE}$$

$$CC10 = ACC_{10} \times \frac{DE10}{DE}$$

$$CC11 = ACC_{11} \times \frac{DE11}{DE}$$

$$CC12 = ACC_{12} \times \frac{DE12}{DE}$$

Where,
CC1, CC2, CC3,……….CC12 is the monthly capacity charge up to 1st, 2nd, 3rd ……12th months of the year respectively.

DE = Ex-bus Annual Design Energy
DE1, DE2, DE3, ……….DE12 are the Ex-bus design energy values up to 1st, 2nd, 3rd ……12th months of the year respectively.

Total capacity charges payable to the generator for the:

1st month = (CC1)
2nd month = (CC2 -CC1)
3rd month = (CC3 - CC2)
4th month = (CC4 -CC3)
5th month = (CC5 - CC4)
6th month = (CC6 -CC5)
7th month = (CC7 -CC6)

8th month = (CC8 -CC7)
9th month = (CC9 -CC8)
10th month =(CC10 – CC9)
11th month =(CC11 -CC10)
12th month =(CC12 -CC11)

and, each beneficiary having firm allocation in capacity of the generating station shall pay for the :

1st month = [ CC1 x WB1)/100
2nd month = [CC2 x WB2 -CC1x WB1)/100
3rd month = (CC3 x WB3 - CC2 x WB2)/100
4th month = (CC4 x WB4 - CC3 x WB3)/100
5th month = (CC5 x WB5 - CC4 x WB4)/100
6th month = (CC6 x WB6 - CC5 x WB5)/100
7th month = (CC7 x WB7 - CC6 x WB6)/100
8th month = (CC8 x WB8 - CC7 x WB7)/100
9th month = (CC9 x WB9 - CC8 x WB8)/100
10th month = (CC10 x WB10- CC9 x WB9)/100
11th month = (CC11 x WB11- CC10x WB10)/100
12th month = (CC12 x WB12- CC11x WB 11)/100

Where,

And, WB1, WB2, WB3, WB4, WB5, WB6, WB7, WB8, WB9, WB10, WB11 and WB12 are the weighted average of percentage allocated capacity share of the beneficiary during the cumulative period up to 1st, 2nd 3rd, 4th, 5th, 6th, 7th, 8th, 9th, 10th, 11th and 12th month respectively.

**INTER-STATE TRANSMISSION**

**Existing provision**

8.67 The existing notification provides for payment of transmission charges of the region on monthly basis in proportion to energy drawal by the beneficiaries. It also provides that when availability based tariff is introduced the monthly transmission charges leviable to each beneficiary shall be computed as per their respective capacity allocation from ISGS. Full transmission charges are recoverable at 98% availability. Payment of transmission charges below 98% to be on pro-rata basis.

8.68 It is pertinent to note that as on date Availability Based Tariff has been introduced in all the five regions. We, therefore, direct that the transmission charges of the region shall be payable in the following manner:

$$\text{Transmission Charges} = \frac{\mathbf{TC}}{\mathbf{12}} \times \frac{\mathbf{MB}}{\mathbf{MS}}$$

Where TC = Annual Transmission Charges of the region payable by all the beneficiaries

MB = Capacity allocation from Central sector generating stations to each beneficiary individually plus contracted power.

MS = Total Capacity from Central sector generating stations plus total contracted power.

8.69 We also direct that full annual transmission charges shall continue to be recoverable at 98% availability and for availability below 98% transmission charges shall be on prorata basis as has been done in the existing tariff notification. Payment of transmission charges shall continue to be done on monthly basis for the next tariff period as well.

### Sharing of charges for inter-Regional assets

8.70 In the Discussion Paper, the methodology proposed for sharing of transmission charges is essentially continuation of the methodology applicable during the current tariff period. The salient features of the methodology suggested in the Discussion Paper are that transmission charges for the inter-regional lines may be shared by the two contiguous regions on 50:50 basis and further shared among the beneficiaries within the respective region. The transmission charges for the inter-regional lines need not be pooled with those for the other transmission assets in the respective region. The transmission charges after deducting the wheeling and congestion charges realised from others for the regional assets (other than the inter-regional assets) should be shared by the "regional beneficiaries", which means beneficiaries located in the region concerned. If an inter-regional asset is used for wheeling by a third party, the balance of the transmission charges after accounting for the payable wheeling/congestion charges, may be shared by the beneficiaries of the contiguous region on 50:50 basis.

8.71 NHPC has supported the sharing arrangement proposed in the Discussion Paper. KSERC has stated that inter-regional lines are essentially meant for providing emergency assistance from one region to another and facilitating economic power and energy exchanges between the connected regions. Based on this, KSERC has supported sharing of transmission charges by the two contiguous regions on 50:50 basis. CSEB has also suggested that transmission charges for inter-regional lines may be shared by the two contiguous regions on 50 : 50 basis and further shared among the beneficiaries within the respective regions. If an inter-regional asset is used for wheeling by a third party, the balance transmission charges after accounting for the payable wheeling and congestion charges may be shared by the beneficiaries of the contiguous region on 50:50 basis.

8.72 BSEB had expressed its agreement with the methodology of sharing suggested in the Discussion Paper, but had desired that the word ‘third party’ may be defined to ward off any future ambiguity. However, subsequent to hearing, BSEB has urged for review of the existing provision of loading of 50% charges of inter-regional link to the beneficiaries of the region. According to BSEB, if the provision continues, inter-regional link may become difficult to be conceived in future, as the constituents are unlikely to sign agreement with POWERGRID. BSEB has opined that sharing of the transmission charges in the ratio of 1/3:1/3:1/3 by the two regions and actual users as applicable up to 31.3.201 based on Ministry of Power notification was a better alternative. BSEB has further proposed that inter-regional links constructed for exporting power from the export-oriented generating stations should be declared as dedicated feeder to the importing region, who shall be the sole beneficiary of the power. According to BSEB, purchase of capacity in the inter-regional links should not be made mandatory rather it should be on voluntary basis.

8.73 GRIDCO has suggested that the transmission charges minus the charges payable by a third party, should be shared by the contiguous states based on the scheduled availability of line, instead of sharing in the ratio of 50:50. APERC has expressed a view that ratio of sharing should be such that importing utility ends up paying higher sharing charges. APERC, MPERC and Utkal Chamber of Commerce and Industry have suggested a method whereby the transmission charges are shared in the ratio of net energy flow. Utkal Chamber of Commerce and Industry has supported the proposal made in the Discussion Paper that the transmission charges should not be pooled with the charges for other transmission assets in the respective region.

8.74 Bharat Chamber of Commerce has also argued that the principle of sharing of the transmission charges in the ratio of 50:50 suggested in the Discussion Paper is not fair to the States surplus in electricity . It has suggested that to reflect extent of reliability support availed by each of the two regions, the charges should be shared as under:

1/3rd to be assigned to importing region

1/3rd to be assigned to exporting region

1/3rd to be shared by two regions based on actual use.

8.75 POWERGRID has stated that presently export of power is from Eastern Region to Western, Northern and Southern Regions. The provision of allocating 50% charges to beneficiaries of Eastern Region only increases their burden, though the importing states would also be benefited by such transactions. In the presentation during the open hearing, POWERGRID has suggested that sharing on the basis of one-third, one-third by the beneficiaries of both the regions and remaining one-third as per use would be the ideal arrangement. It has further suggested that these charges should not be pooled in the respective regions. MPSEB has also expressed a view that there is no rational to pool transmission charges for the (inter) regional lines with the transmission charges of the respective regions.

8.76 We are of the opinion that even if the flow is unidirectional, as presently is the case with Eastern Region, the beneficiaries of exporting region get benefited by such export, as export of surplus energy reduces their liability of paying the fixed charges of generating stations levied in proportion of capacity allocated in the absence of matching demand. We, therefore, direct that sharing of the charges for inter-regional lines should continue to be on the basis of 50:50 by the two connected regions. If an inter-regional asset is used for wheeling (by a party which is not a beneficiary of any of the two regions connected by such a line), the transmission charges for such wheeling shall be paid pro-rata to the capacity utilised and shall be used for reduction in the transmission charges of the line before dividing these charges in the ratio of 50:50. The subject matter, however, is and is being taken up separately by the Commission under open access regulations. The present practice of not pooling the share of transmission charges for inter-regional assets payable by a region with the transmission charges of the other assets shall continue to be followed.

## Transmission Charges for North-Eastern Region

*8.77* As regards transmission charges for North-Eastern region, the Commission's order dated 1.1.2002 in Petition No. 40/2000 in the matter of approval of transmission tariff for transmission system associated with Kathalguri Project, Kopili Extn.Stage-I and augmentation scheme for NE Region and Review Petition No. 110/2000 on petition No. 40/2000 is applicable up to 31.3.2004. The relevant part of the order is reproduced below:

> "In the light of the foregoing, we direct that the respondents shall be liable to pay the transmission charges @ 35 paise/kwh of the power transmitted in the region. This tariff shall be applicable from 1.2.2000 to a period up to 31.3.2004 or till such time the power generation matching the transmission capacity is available, whichever is earlier. However, we wish to advise the Central Government to finalise an appropriate relief package for the NE region. If the Central Government finalise relief package, then the difference between actual tariff and the tariff of 35 paise/kwh which we have ordered, shall be provided from the relief package to the petitioner. If this does not happen, petitioner would have to bear the difference. We expect that the petitioner, however, would pursue the matter and obtain an early favourable decision from the Central Government. The petitioner may get this petition revived in that eventuality. As a corollary of this direction, the petitioner need not file transmission tariff petitions for any other transmission system in the region since other transmission systems get covered by these directions, which are in the context of the power transmitted and not based on the terms and conditions notified by the Ministry of Power on 16.12.1997."

8.78 Since the relief package is yet to be announced by the Central Government, we order that the existing dispensation shall be continued in respect of NE Region, till issue of the relief package gets resolved. As and when the issue is sorted out, POWERGRID is granted liberty to approach the Commission for appropriate relief.

## Conclusion

8.79 The draft regulations on terms and conditions of tariff to be effective from 1.4.2004 have already been published with a view to inviting comments/suggestions from the stakeholders, to be submitted by 23.1.2004. This order incorporates the reasons in support of the provisions made in the draft regulations. We direct that the last date for submission of comments/suggestions by all concerned, be extended up to 31.1.2004.

| | |
|---|---|
| **Sd/-** | **Sd/-** |
| **(K.N. SINHA)** | **(ASHOK BASU)** |
| **MEMBER** | **CHAIRMAN** |

**New Delhi, dated the 16th January, 2004**

**SCHEDULE**

1. National Thermal Power Corporation
2. National Hydro Power Corporation
3. Power Grid Corporation of India Ltd.
4. Nevyeli Lignite Corporation
5. North Eastern Electric Power Corporation Ltd.
6. Damodar Valley Corporation
7. Sutlej Jal Vidyut Nigam Ltd. (NJPC)
8. Tehri Hydro Development Corporation
9. Shri Mrutunjay Sahoo, Joint Secretary & Financial Adviser, Ministry of Power
10. Power Trading Corporation.
11. Bhakra Beas Management Board
12. Punjab State Electricity Board
13. West Bengal State Electricity Board
14. Kerala State Electricity Board
15. Assam State Electricity Board
16. Bihar State Electricity Board
17. Maharashtra State Electricity Board
18. Tamil Nadu State Electricity Board
19. Chattisgarh State Electricity Board
20. Andhra Pradesh State Electricity Regulatory Commission
21. Himachal Pradesh State Electricity Regulatory Commission
22. Rajasthan State Electricity Regulatory Commission
23. Orissa State Electricity Regulatory Commission
24. Kerala State Electricity Regulatory Commission
25. Tamil Nadu State Electricity Regulatory Commission
26. Karnataka State Electricity Regulatory Commission
27. Rajasthan Rajya Vidyut Prasaran Nagam Ltd.
28. Andhra Pradesh Transmission Corporation Ltd.
29. Orissa Power Generation Corporation
30. Karnataka Power Corporation Ltd.
31. Grid Corporation of Orissa
32. West Bengal Power Development Corporation Ltd.

33. Government of Maharashtra
34. Uttar Pradesh Rajya Vidyut Vyapar Nigam Ltd.
35. Uttar Pradesh Power Corporation Ltd.
36. Kolkata Electric Supply Company
37. Bombay Subarban Electricity Supply
38. Gujarat Paguthan Energy Corporation Private Ltd.
39. GMR Infrastructure Ltd.
40. Power Finance Corporation
41. Infrastructure Development Finance Corporation
42. Industrial Development Bank of India
43. Department for International Development (DFID)
44. Rabo India Finance Private Ltd.
45. PHD Chambers of Commerce and Industry
46. Bengal National Chamber of Commerce
47. Bharat Chamber of Commerce
48. Utkal Chamber of Commerce and Industry Ltd.
49. Confederation of India Industry
50. Premier Mott Mcdonald
51. B.P. International Ltd.
52. Er. Bhanu Bhushan, Director (Opertions), PGCIL
    (in his personal capacity)
53. Er. S.K. Aggarwal, Ex. Member, CEA
54. S.R. Paranjpe, Retd. Director, Indira Gandhi Centre
    for Atomic Research, Kalpakkam
55. Shri K.P. Rao
56. Tata Power Company
57. National Working Group on Power Sector