Section - 4

THE COMMISSION'S ANALYSIS ON THE REVENUE REQUIREMENT OF THE JSEB

4.1 The Commission has assessed the ARR for the Board for FY2003-04 based on the first and the revised petition submitted, additional information received from the Board, and discussions held with the Board's staff during 22nd November 2003 to 24th November 2003 and on 8th December 2003. During the proceedings of tariff determination, the Commission interacted orally as well as in writing with the petitioner. Besides, other stakeholders such as TVNL, NTPC, CEA and the State Government were also consulted to further refine the quality of information filed by the petitioner.

4.2 At the outset, the Commission would like to draw attention to the following tight spots under which the Commission has analysed the tariff petition submitted by the Board:

4.2.1 The unfinished task related to the transfer of assets and liabilities between the BSEB and the JSEB.

4.2.2 The accounts for FY 2001-02 and FY 2002-03 are still not audited.

4.2.3 Despite repeated reminders, the Board did not provide underlying principles/assumptions for estimates proposed in the tariff petition.

4.2.4 Data inconsistency not only within the tariff petition but also between different departments and documents of the Board.

4.3 The Commission has considered the impact of data uncertainty on tariff and has assessed the authenticity of information submitted by the Board through the BSEB's audited accounts for FY 2000-01; provisional accounts of the JSEB for FY 2001-02 and provisional budget of the JSEB for FY 2003-04.

4.4 The Commission is concerned about uncertainties with regard to certain items due to non-finalisation of division of assets and liabilities between the BSEB and the JSEB. Further, the Board has proposed certain capital expenditure without any supporting documents. The Commission notes that as and when datasets improve it may, subject to analysis of prudence, allow the expense for meeting liabilities arising in this regard. However, the Commission is not in favour of first lowering the tariff by not taking into account any unforeseen liabilities and then increasing the tariff when these liabilities become compulsory to incur. The Commission has, therefore created a 'Temporary Contingency Reserve' in the backdrop of such uncertainties, which would exist only for FY 2003-04 and should not be required in subsequent years.

4.5 The Commission has adopted a process of benchmarking to assess the performance of the Board. Benchmarking can be done through a comparison with other similar entities or a comparison of a utility's performance against itself on a time scale or a comparison with an efficient utility. On certain key criteria, the Commission has benchmarked the Board's performance with the performance of utilities in other reforming states and with various norms considered by the CERC and the CEA. Wherever possible, the Board's performance has been measured against its previous achievements in FY 2001-02, FY 2002-03 and during the first seven months of FY 2003-04.

4.6 The Commission acknowledges the objections related to poor supply of electricity and inefficient costs, wherein the consumers have questioned the fairness of passing through these costs in terms of higher tariff. Some of the major objections related to revenue requirement are listed below:

1) It is not possible to accurately assess the revenue requirement unless the revenue account of the Board for FY 2001-02 and FY 2002-03 are audited.

2) The increase proposed by the Board in employee cost and O&M cost is on a higher side given the prevailing economic indicators of WPI and CPI.

3) The statutory return of 3% should be allowed only if the Board is functioning efficiently.

4) The Board is producing electricity at a very high cost, as the Patratu Thermal Power Station (PTPS) is operating at very low PLF and is plagued with other operational inefficiencies.

5) The consumers have objected to the high Transmission and Distribution (T & D) loss including mass pilferage prevailing in the state with the connivance of the Board employees.

6) Lastly, the consumers have strongly objected to poor quality of supply and service.

4.7 The Commission has considered the consumers' views while approving the revenue requirement. The following paragraphs discuss the Commission's detailed analysis along with the ruling on each element of the revenue requirement.

Sales Projection

4.8 As mentioned in Section 2 of the Tariff Order, the Board has provided two estimates for FY 2002-03. The sales mix has been described based on the figure of 2481 MU while the Board contends that sales have risen by 10% to 2560 MU for the same year. The category wise break up of both these estimates are tabulated as below:

Table 4.1: Sales estimates by the Board for FY 2002-03

	FY 2002-03	
	I	**II**
Domestic	524.55	544.14
Commercial	134.8	138.27
LT Industry	147.74	194.18
HT Industry	1260.87	1268.93
Public lighting	33.65	33.00
Traction	336.11	335.68
Irrigation Private	33.87	37.50
Irrigation State Tube well	9.9	8.63
	2481.49	2560.33

4.9 The above table not only reflects the non-seriousness but also underlines the need for improving the information base of the Board urgently. The Commission is concerned with the fact that even though seven months of FY 2003-04 have passed, the Board has still not been able to compile correct sale figures for FY 2002-03. The Board has projected sales of 3165 MU for the FY 2003-04 assuming an increase of 27.5% over the previous year figure of 2481 MU. This increase has been assumed for each category. The Board has failed to provide sufficient details for this increase except that out of 27.5%, 10% increase is on account of the rising trend in demand and the rest is on account of proportion of the T&D losses converting into recorded consumption through loss reduction measures and metering programme being undertaken by the Board.

4.10 Against this backdrop of data inconsistency and data insufficiency, **the Commission is of the view that the Board needs to undertake a detailed study for load research and demand forecast in order to correctly understand its short term and long term peak energy requirements.**

4.11 The Commission has considered the circle wise revenue statement for each month of FY 2002-03 to validate the sales levels provided by the Board. Through this, the sales for FY 2002-03 were estimated at approximately 2481 MU showing an increase of 7% over its previous year. The year on year growth in sales is tabulated as below:

Table 4.2: The Commission's analysis on past sales

	2001-02	**2002-03**	**% Growth**
Domestic	494.67	524.55	6%
Commercial	125.70	134.80	7%
LT Industry	176.53	147.74	-16%
HT Industry	1153.57	1260.87	9%
Public lighting	30.00	33.65	12%
Traction	305.17	336.11	10%
Irrigation Private	34.09	33.87	-1%
Irrigation State Tubewell	7.84	9.90	26%
	2327.57	2481.49	7%

4.12 The revenue statements were also scrutinized for the first quarter of FY 2003-04, however, since data from some divisions/areas was yet to be included, the actual levels of consumption recorded for these three months remained largely unreliable. Overall, the Board has not been able to provide the minimum time series data required to study the trend in sales, which has constrained the Commission in forecasting the sales for FY 2003-04.

4.13 Another constraint with regard to correct estimation of sales is un-metered consumption. Again, the Board has not been able to provide data on account of which it has estimated un-metered sales except that these are based on average load in each category & sub-category, and average hours of supply to each of them.

4.14 Of the total consumption in FY2002-03, 10% is un-metered that includes, un-metered sub categories in domestic and commercial category while irrigation and streetlight that are fully un-metered. The average consumption of un-metered domestic and commercial category is 52 Kwh per month and 130 Kwh per month respectively. These levels seem unrealistic, especially for the commercial category, given the supply situation in rural areas of the State.

4.15 Though the proportion of un-metered sales is low in Jharkhand as compared to many other states in India, an accurate estimation in this regard is imperative to measure the exact level of T&D losses and also to improve the supply in rural areas.

4.16 The Board has proposed few new sub categories in the existing tariff schedule. These have been discussed as below:

Kutir Jyoti

4.17 In domestic, the Board has proposed a sub category of Kutir Jyoti with 200 watts of connected load per connection. It has proposed to sell 19 MU to 26550 consumers in this category at an average consumption of 61 units per month.

4.18 The Commission would like to bring to the notice of the Board that Kutir Jyoti is a single point connection scheme for consumers Below Poverty Line (BPL). The Commission has interacted with REC (Rural Electrification Corporation) with regard to the status of this scheme. REC officials mentioned that average load in India for a Kutir Jyoti connection is 40 watts and on average they receive 3-4 hours of supply. If we use this norm, average consumption per month per consumer could not increase 5 units, whereas the Board has proposed 48 units per month per consumer (200 Watt*8 hours*30 days/1000).

4.19 Since a single point could be provided up to 100 watts, the Commission approves 100 watts instead of the proposed 200 watts for a Kutir Jyoti connection. Further, given the supply situation in the State, the Commission views that the Board's contention to supply 16-18 hrs is highly unrealistic. Against this, based on 8 hours of daily supply, the Commission approves a total sale of 7.75 MU. On these bases, the average consumption level as approved by the Commission is 24 units per month.

4.20 During discussions with the Board, the Commission found that the existing single point connections, which would be converted into Kutir Jyoti, are withdrawing more power than their connected load permits. The Commission directs the Board to undertake strict measures to check such consumption and bring all such consumers in the next domestic category where the permissible load is up to two kilowatts.

Domestic high tension

4.21 The Board has proposed another new sub category in the domestic segment, namely Domestic High Tension (DSHT). This would be applied for power supply at 11KV to housing colony and housing complex for loads above 75KW. The Board estimates a sale of 1.6 MU for this category, assuming a 5% outflow of sales from the existing DS-III category. The Board had not conducted any study on the number of housing colonies/complexes and has not surveyed the number of consumers that are likely to avail this scheme. Against this lack of information, the Commission accepts the 5% of DS-III consumption for this category as proposed by the Board.

The Commission's approval with regard to sales

4.22 The Commission has evaluated the performance with respect to the metering programme being undertaken by the Board and found the progress to be very slow on this front. The Board has not been able to quantify reduction in T&D losses that would be achieved through its metering programme and the subsequent increase in total consumption. In this background, the proposed increase of 27.5 % is high and approving energy requirement on this basis would tend to result in higher T&D losses and not higher sales. This would increase the total energy requirement, and thereon the power purchase and its cost.

4.23 The Commission would not like to restrain consumption in a newly formed State and strongly believes that power sector reform is the backbone for economic growth in the State, which would require uninterrupted power supply especially to industrial consumers. The Commission would therefore like to encourage sales, and against this, it approves a 10% increase in sales across all the categories for FY2003-04, which is marginally higher than the growth witnessed in the previous year. The proposed and approved sales estimates are tabulated as below:

Table 4.3: The Commission's approved sales for FY 2003-04

	2003-04	
	Proposed	**Approved**
Domestic	669	577
Commercial	172	148
LT Industry	188	163
HT Industry	1608	1387
Public lighting	43	37
Traction	429	370
Irrigation Private	43	37
Irrigation State Tubewell	13	11
Total	3164	2730

4.24 The Commission submits that above estimates are not based on a scientific assessment and it believes that in the next petition the Board would be able to provide correct estimates for category wise consumption in the past. **For this purpose, the Commission directs the Board to estimate circle wise consumption by different categories including un-metered category. The Board in the next tariff petition would also have to furnish circle-wise number of hours of supply to various categories of consumers.**

Transmission and Distribution (T&D) Losses

4.25 The T&D losses estimated by the Board is 47.66% for the FY 2002-03. The Board has calculated T&D losses taking into account the difference between the energy injected into the Board's grid system and the energy billed stating that this methodology is realistic.

4.26 It has been mentioned by the Board that supply at lower voltages to majority of the consumers is resulting into a very high level of technical losses. As for commercial losses, the primary reason is rampant pilferage of power in the state. The Board has proposed to bring down the T&D losses by 9.66% to a level of 38% in FY 2003-04, as it is undertaking massive metering programme under the APDRP scheme, which includes introduction of tamper proof electronic energy meters and feeder & distribution transformer metering. According to the Board, eleven circles have been identified for this programme at a project cost of Rs 337.24 Crore. Besides, up gradation & augmentation of lines and substation is also being undertaken by the Board to reduce the technical losses.

4.27 The Commission has reviewed the status of metering, which is the basis for T&D loss reduction, as proposed by the Board. The estimates obtained in this regard are tabulated as below:

Table 4.4: Status of metering

	Name of work	Unit	Target for 2003-04	Achievement as on Sept' 03	% target achieved
1	Feeder & Distribution Transformer metering	No.	9058	1457	16%
2	Consumer Metering				
2a	Single Phase	No.	300000	23168	8%
2b	Three Phase TV Meter with CT	No.	3000		
2c	Three Phase Direct Meter	No.	17000		
3	HT TV Meter with Metering Unit	No.	272		
4	33/11 KV New Power S/S	No.	24		
5	New Line (HT & LT)	Kms.	1100	22	2%

4.28 It is evident from the foregoing table that a very low proportion of the targets have been met in the first six months and it is viewed that these are not likely to be met fully in the ensuing six months of FY 2003-04. In such a scenario, the increase in recorded consumption would not be very considerable, as had been claimed by the Board, in which case the 10% reduction target seems unrealistic and unachievable.

4.29 The Commission observes that since close to 70% of the entire consumption of electricity in the Board's system is attributed to industry and railway traction segments, the incidence of technical losses should be comparatively lesser as compared to other states where consumption by agriculture and other unmetered categories is very high thereby leading to higher losses. With regard to commercial losses, the Commission holds that these occur due to inadequate supervision on part of the Board, and should ideally not be allowed to pass through the consumers. Since majority of the sales is in industrial sector, the Commission believes that industries may also be responsible for these commercial losses. **The Commission directs the Board to constitute a task force to monitor the T&D loss reduction program in the State and the task force should quarterly update the Commission on various milestones achieved by the Board.**

4.30 The Commission however, understands that these losses could not be brought down suddenly and it will take a few years until these losses could be reduced to technically permissible levels. **Against this, the Commission approves a reduction target of 5% to bring down the loss level up to 42.66% in FY 2003-**

04. The remaining 5% reduction proposed by the Board would be adjusted through rate of return by not allowing any amount on this account for the purpose of tariff determination. The Commission would like to highlight that the Board could gain Rs.104 Crore through an additional 5% reduction in T&D losses, which would more than compensate for the disallowed rate of return. This saving would occur in terms of reduced power purchase from DVC (last plant in the merit order) by the Board.

4.31 As per Section 61(f) of the Electricity Act, 2003, an SERC has to be guided by multi year tariff principles while determining tariff for the state. The Commission holds that sufficient and reliable data is a pre requisite for fixing multi year targets without which such a concept is not likely to prove effective, as has been experienced in few states that had undertaken initiatives in this direction. The Commission therefore, abstains from fixing multi year targets against this backdrop of data insufficiency and would prescribe the same as data sets improve upon time.

4.32 The Commission observes that an assessment of T&D losses becomes imperative due to the presence of un-metered consumption. In fact, the foremost requirement in accurate measurement of T&D losses is correct estimation of un-metered consumption. There are various categories that are un-metered as of now and the Board has not been able to provide full justification in arriving at their consumption levels. It is quite possible that excess T&D losses are being masqueraded as higher un-metered consumption; in which case the losses, as reported by the Board could even be higher. The Commission holds that information base of the Board, which is not only inadequate but is also marked with various inconsistencies, has been a major constraint in authenticating the T&D losses. In this backdrop, the Board is directed **to undertake a proper energy audit of its system and provide a voltage-wise break up of technical and commercial losses in the next petition. The Board should also provide a circle wise break up of its T&D losses in the next petition. This would help in benchmarking various circles and introducing competition along with incentives for the employees among the various circles.**

4.33 **The Commission further directs the Board to undertake a study to estimate category wise un-metered consumption and provide the results in the next petition.** The study should reveal the number of hours of supply and the connected load in various un-metered categories. **In this regard, the Commission also directs the Board to furnish a circle wise data on the average supply hours in FY 2002-03 and FY 2003-04.** The Commission agrees that this would presumably be based on availability at the substation and not actually at the consumers' end.

4.34 While the Board is directed to conduct studies, the Commission notes that estimation studies could not be a substitute to complete metering, and as Section 55(1) of the Electricity Act, 2003 mandates all the utilities to meter entire consumption within two years from the date of issue of this Act, it is in the interest of the Board to undertake metering programme, as envisaged under the APDRP scheme more aggressively and meet the specified targets on time. The Commission directs the Board to submit an action plan by March 2004 for complete metering by the end of June 10, 2005 (two years post the issue of the Electricity Act on June 10, 2003). It is further directed that no new connection should be issued without a meter from the date of issue of this order.

Collection efficiency

4.35 In addition to T&D losses, the Commission recognizes inefficiencies that exist with respect to revenue collection. Though the Board has not furnished any information on collection efficiency in the tariff petition and its calculation of income from sale of power is based on 100% collection efficiency, the Commission has scrutinized this aspect from the supplementary information provided by the Board that included collection figures for FY 2002-03. It was found from this data that against the billed amount of Rs.898 Crore, the Board has collected Rs. 800 Crore, which includes dues outstanding against government organizations. A measure to compute overall losses including those arising on account of collection inefficiency is Aggregate Technical and Commercial (AT&C) losses. It is expressed as the difference between units realized and units input into the utility as a ratio of units input into the utility. The Commission has attempted to estimate the AT&C losses in the Board's system for FY 2002-03. The estimates obtained in this regard are tabulated as below:

Table 4.5: AT&C losses for FY 2002-03

A T&C LOSSES FOR FY 2002-03	
Total Energy Input (in MU)	4731
Total Sale (in MU)	2481
Revenue from Sale (in Rs. Crore)	898
Total amount collected (in Rs. Crore)	800
T&D loss	48%
Collection efficiency	89%
Units commensurate with amount collected (in MU)	2211
Collection as a % of Energy input	47%
AT & C loss	53%

4.36 The Commission would like to mention that like any other business entity, the Board should be run on commercial lines, and it should try to improve its cash flow by collecting the entire amount billed. For FY 2003-04, the Commission approves interest on working capital to meet the 5% collection inefficiency.

4.37 Based on sales of 2730 MU and on a T&D loss level of 42.67%, as approved by the Commission, the total energy requirement is estimated at 4761 MU. This energy requirement has to be met partly from own generation and partly from purchase from various stations.

Table 4.6: Sales, T&D and energy requirement for FY 2003-04

	Proposed	Approved
Sales (MU)	3165	2730
T&D Losses (%)	38%	42.67%
Energy Requirement (MU)	5105	4761

Energy Generation from the Board's stations

4.38 The Board, in its first petition, had proposed a gross energy generation of 1472 MU for FY 2003-04, assuming an increase of 10% over the last year's level of 1338 MU. However, in the revised petition, the Board has proposed that they would not able to generate more than the last year's level, therefore, a gross generation of 1338 MU should be considered for FY 2003-04.

4.39 The trend in generation for the last two years and the proposed estimates for FY 2003-04 are tabulated as below:

Table 4.7: Status of generation (PTPS and SHPS)

Year	PLF	Gross Generation (MU)	Auxiliary Consumption (MU)	Auxiliary Consumption (%)
2001-02	25%	1368	203	15%
2002-03	24%	1338	238	18%
2003-04 (Prop)	24%	1338	238	18%

4.40 The auxiliary consumption proposed by the Board is 238 MU for FY 2003-04. The Board holds that different units of the plant have not been able to generate optimally due to lack of adequate repair and maintenance work and few of them are out of operation as they are undergoing major repairs. The Board maintains that tripping of a unit is very frequent and they keep a unit or two non-operational so that they can activate the reserved unit in case of a tripping. Therefore, all units cannot run simultaneously, and are being run alternatively. The Board mentioned that, due to these factors, the Plant Load Factor (PLF) of PTPS is very low and has been estimated at 26% for FY 2002-03. During discussions with it, the Board stated that poor maintenance of the PTPS substation has also been responsible for high auxiliary consumption and low PLF, besides this resulting into high oil consumption.

4.41 The Commission surveyed the various documents on PTPS generation and also visited the power plant to assess the situation. The Commission is extremely surprised at inefficiencies with respect to the management of generation. The Commission holds that despite being situated in a pit head with adequate availability of water for washing of coal, the plant has been performing at an abysmally low PLF plagued with various inefficiencies arising due to the negligence.

4.42 The Commission undertook a review of the 'Monthly Progress Report' of PTP Station for a few months. It was found that the Station Heat Rate (SHR), which is a ratio between heat input and energy generated and is used as an indicator to assess the performance of generating stations, is 4269.13 Kcal /kwh for FY 2002-03. This level is very high when compared with the normally accepted norm of 2500 Kcal /kwh. It was also found that few units of the plant had been operating at far lower than the average PLF. For instance, unit no. 7 had operated at a PLF of 1.20% and 4.21% for the month of September and October 2003 respectively.

4.43 Apart from low PLF, the auxiliary consumption of the plant is very high. It is estimated at 19% for FY 2002-03. This is very high when compared with the CEA norm of 10% (maximum) for similar power stations. The Board holds that such a high level of auxiliary consumption is due to common auxiliary facilities catering to two or more units. The Board failed to provide auxiliary consumption for each unit separately, and also for each unit's boiler, TG & off site auxiliary consumption. It has also been found by the Commission that staff colonies & other commercial settings situated near the plant are also being supplied through station transformer due to which it is difficult to ascertain the exact level of actual auxiliary consumption.

4.44 The Commission recognizes that some units of the plant are very old and it would not be possible to run them at a high PLF but the prevailing level of PLF is exceptionally low, lower than the generally accepted norm. Similarly, the auxiliary consumption is very high when compared with different thermal plants in the country. The Commission observes that the burden of this inefficiency should not be passed through to the consumers. The Commission directs the Board to undertake necessary measures in terms of economic scheduling of working units in order to reduce SHR from its existing level and increase the PLF to its optimal level. The Commission also directs the Board to account separately the consumption in the nearby areas of PTPS and estimate auxiliary consumption net of this level.

4.45 From the generation data for the first seven months of FY 2003-04, it is estimated that the PLF of PTPS has in fact deteriorated to 20%. The auxiliary consumption for the same period is estimated at 16%. Besides, against the target of 1252 MU, as fixed by the Board, it had been able to generate only 613 MU in first seven months of FY 2003-04. A review of month-wise data for the last two years reveals that the PTPS had been operating at higher PLFs. For instance, the average PLF for April 2002 is 31%; even this year the month of April recorded a PLF of 27%. Similarly, the auxiliary consumption has been recorded at lower levels in the past. For instance, it was 13% for the months of July and August of FY 2003-04. The Commission believes that with adequate conduct of operations, the PLF could be brought up to a technically acceptable level and auxiliary consumption could be brought down. In fact, the auxiliary consumption could be brought down immediately after accurately accounting and billing for the supply to nearby areas of PTPS. The Commission thereby on the basis of internal benchmarking has approved the PTPS generation at a PLF of 27% and auxiliary consumption at 13% for the ensuing five months of FY 2003-04. Combining the generation obtained from this with the actual levels for the first seven months the gross generation and net generation approved for FY 2003-04 is 1189 MU and 1016 MU respectively.

4.46 The Commission has undertaken a review of SHPS generation for the first five months of FY 2003-04, and has found that the level of generation in this period is higher than the corresponding level of the previous year. The Board has stated that it would be able to generate optimally for the coming seven months as the water level is quite full but has not submitted any estimate of SHPS generation as such. Against this, the Commission has taken into account generation of the last seven months of FY 2002-03 as generation for the corresponding period of FY 2003-04. This has been combined with the actual levels of the first five months of FY 2003-04. The SHPS generation therefore, is estimated at 116 MU for FY 2003-04 and the total net generation of the Board at 1132 MU.

Table 4.8: Energy generation approved by the Commission for FY 2003-04 (in MU)

	Gross generation	**Auxiliary consumption**	**Net Generation**	**Gross generation**	**Auxiliary consumption**	**Net Generation**
	Proposed			**Approved**		
PTPS	1252	237.79	1014	1189	174	1016
SHPS	86	0.22	86	116.2	0.2	116
Total	1338	238	1100	1305	174	1132

4.47 The Commission has already approved total energy requirement of 4761 MU. Since the Commission has approved a net generation of 1132 MU the remaining 3629 (4761-1132) MU has to be met by power purchase from TVNL, DVC and central sector units.

Table 4.9. Gross power purchase requirement (MU)

Sl.No		
1	Sales (MU)	2730
2	T&D Losses (%)	42.67%
3	Energy Requirement (MU)	4761
4	Net Generation (MU) in JSEB's plants	1132
5	Net Power Purchase (MU) [3-4]	3629

Power purchase (MU)

4.48 The Board has projected a gross power purchase requirement of 3994 MU for FY 2003-04. It has assumed an increase of 10% in the quantum of power purchase over FY 2002-03 level. The power purchase from different sources in the last two years and the proposed requirement in FY 2003-04 is tabulated as below:

Table 4.10: Proposed power purchase (MU)

		2001-02	**2002-03**	**2003-04 (Proposed)**
1	Farakka	103	353	388
2	Kahalgaon	149	204	224
3	Talcher	105	80	88
	NTPC-Total	**358**	**637**	**700**
4	Rangit	131	21	23
5	Kuruchi	2	0	0
6	Chuka	193	27	29
	NHPC-Total	**326**	**47**	**52**
7	DVC	1538	1774	1951
8	TVNL	931	1154	1268
9	WBSEB	23	21	23
10	TISCO	7	0	0
	Total	**3184**	**3633**	**3994.00**

4.49 The Board has not provided any explanation for the proposed quantum of power purchase from various stations except that since there had been an increase of 10% in power purchase from April'03 to August'03 the same trend has been extrapolated for the ensuing months to arrive at an estimate of 3994 MU. In the supplementary information submitted by the Board, it has provided the power purchase amount for additional two months for some sources. Besides, taking into account the data provided by the Board, the Commission has cross-checked the availability of power from various stations including TVNL and NTPC and has recalculated the quantum of purchase by the Board.

4.50 The Commission, in its judgment, has approved merit order dispatch, i.e. the cheaper source of power should be first optimally availed before buying from the second cheapest plant and the most expensive plant should be purchased in the end. In case of the JSEB, the most expensive plant is DVC and therefore, the Board should minimize purchase from DVC and should try to maximize purchase from TVNL and central generating stations.

Tenughat Vidyut Nigam Limited (TVNL)

4.51 The Tenughat Vidyut Nigam Limited (TVNL) is a thermal generation plant located in the state of Jharkhand. Prior to the bifurcation of erstwhile Bihar, the TVNL catered to the entire state. However, post bifurcation, TVNL has come under the ownership of the Government of Jharkhand and thereon it has been supplying power to the JSEB only. It has an installed capacity of 420 MW with two units of 210 MW each. In FY 2002-03, the PLF of two units (420 MW) was 37.18% with generation of 1369 MU. According to the TVNL, the low PLF is primarily because of inadequate evacuation capacity, poor maintenance of the transmission lines and lack of demand from the JSEB. TVNL also stated that in first seven months of FY 2003-04, they were able to utilize only 180-200 MW of their total capacity, as demand by the Board was 120-140 MW only.

4.52 In terms of transmission capacity, the plant has two single circuit transmission lines, wherein one goes towards the Bihar-Sharif substation and the other towards the PTPS substation. During discussions with the TVNL officials, it was discovered that TVNL has initiated to augment the existing transmission capacity and it is expected that by the mid of December, line would be charged and would be able to evacuate 380-400 MW of electricity. The TVNL officials acknowledged that this would be possible only if the Board is able to maintain the transmission line & Patratu substation and most importantly, the Board is able to demand 380 MW.TVNL has also submitted to the Commission that in case the Board is not willing to avail the full capacity, they would have to sell their energy in open market, may be through PTC.

4.53 In this context, it is to be noted that with emergence of the Electricity Act 2003, the TVNL is allowed to trade its power, and it if does so, the JSEB would lose an important source of cheaper power. Further, under this new regime of the Act, the existing SEBs would be restructured into separate generation, transmission and distribution companies. The JSEB should carefully look at various options of reducing their cost, so that they can become competitive in the changing scenario as the Act mandates open access, trading and multiple licensees in an area.

4.54 The Commission believes that it is the responsibility of the Board to augment and maintain the existing transmission capacity. The Commission would like to highlight that the Board has proposed three years back that necessary infrastructure would be created to evacuate the entire energy from TVNL. However, no work has been undertaken in this regard. The proposal for setting up a transmission line from TVNL to Hatia and a similar proposal for setting up a transmission line from TVNL to Bokaro (DVC area) have not been pursued with.

4.55 The Commission holds that with 420 MW of capacity and with a PLF of over 75%, the TVNL would be able to cater cost effectively to the Board's demand of power purchase if there's proper evacuation capacity. Sourcing maximum power of the TVNL would also reduce the burden of transmission loss, the cost of which has to borne by the utility while purchasing power from outside sources. It is unfortunate that a cheaper source of power is lying unutilised due to negligence of the Board. Further, the cost effectiveness of the TVNL could be gauged comparing it with other sources:

Table 4.11: Cost comparison of various sources of power

Source of power	Average cost of supply for 2002-03(in Rs./ unit)
NTPC-Kahalgaon	2.23
WBSEB	3.58
DVC	2.61
Rangit	2.11
TVNL	1.68

4.56 It is therefore advised that the Board undertakes the necessary capital and R&M expenditure to augment its transmission capacity, and an action plan in this regard should be submitted to the Commission within one month from the date of issue of this order.

4.57 For the current year, the Commission has analysed the first seven months of purchase from the TVNL and the same is shown in the table below:

Table 4.12: Purchase from TVNL in past eight months (MU)

Month	MU purchased	PLF against 190 MW capacity
Apr-03	98.87	70%
May-03	106.97	81%
Jun-03	124.92	88%
Jul-03	101.21	74%
Aug-03	101.14	72%
Sep-03	107.5	76%
Oct-03	100.62	71%
Nov-03	115.00	84%
Till Nov 03	856	77%

4.58 For the month of December, the Commission has approved the same purchase as was done in the last month. However, for January'04 to March'04, the Commission has approved purchase from TVNL on the basis of 380 MW of capacity and applying the past average PLF of 77%. Accordingly, the purchase from TVNL is approved at 1603 MU against 1269 MU proposed by the Board. The approved power purchase from TVNL is shown in the Table as below:

Table 4.13: Approved power purchase from TVNL (MU)

Months	Approved MU
Purchase till Nov 2003	856
Dec-03	115
Jan-04	218
Feb-04	197
Mar-04	218
Total approved power purchase from TVNL	1603

Central generating stations (CGS)

4.59 The Board has projected 752 MU of power purchase from central sector stations assuming an increase of 10% over FY 2002-03 levels. The Commission is concerned about lack of power purchase planning by the Board. This is evident from the fact that since the JSEB's share in Central sector plants is fixed, the Board is still assuming an across the CG stations increase. This reflects either negligence on the part of the Board while submission of the petition or it reflects lack of understanding.

4.60 The power purchased in the previous year and the actual purchase in the first seven months of FY 2003-04 from central sector stations is tabulated as below

Table 4.14: Proposed and actual power purchase from CGS

	2002-03	**2003-04 (Proposed)**	**First seven months actual for FY 2003-04**	**Projected for FY2003-04**
Farakka	353	388	102	175
Kahalgaon	204	224	71	122
Talcher	80	88	143	246
NTPC-Total	**637**	**700**	**316**	**542**
Rangit (NHPC)	21	23	1.42	2.44
Kuruchi (Bhutan)	0	0	0	0
Chukha (Bhutan)	27	29	11	19.12
Total	**685**	**752**	**329**	**564**

4.61 As it is evident from the above table that the actual trend of the power purchase has gone down in the first seven months of FY 2003-04. Extrapolating this trend for the entire FY2003-04 gives an estimate of 564 MU, which is lesser than the proposed 752 MU of purchase and the 685 MU purchased in FY 2002-03.

4.62 The Commission has gone into the detail of this issue cross verifying from NTPC and CEA. It has closely looked at the share of the JSEB in central generating stations and has also assessed the trend of Board's energy entitlement. The share of Jharkhand in various stations is tabulated as below:

Table 4.15: Share of Jharkhand in NTPC, NHPC and other stations

Station	**Installed capacity**	**% share**	**MW share**
Farakka	1600	3.0%	48
Kahalgaon	840	3.5%	29
Talcher	1000	4.3%	43
Rangit (NHPC)	60	0.7%	0
Chukha (Bhutan)	270	0.9%	2
Kurichu (Bhutan)	60	0.0%	0
Total	3830	3.2%	123

4.63 The Commission holds that the Board should conduct proper planning with regard to utilization of CGS share. This is paramount under the Availability Based Tariff (ABT) regime. The Commission has also crosschecked from NTPC, regarding the entitlement against the actual drawl by the Board. The same is reproduced below.

Table 4.16: Entitlement and actual drawl from NTPC stations

	Farakka		**Kahalgaon**		**Talcher**		**Total**	
Month	Entitlement	Drawal	Entitlement	Drawal	Entitlement	Drawal	Entitlement	Drawal
April	6	4	4	3	5	4	15	11
May	20	19	14	12	25	25	58	55
June	15	10	12	8	27	18	54	37
July	16	14	13	9	25	23	55	46
August	23	20	19	13	29	29	71	61
September	18	15	18	12	25	22	61	49
Total	98	81	79	57	136	121	313	258

4.64 It is evident from the table, against a total entitlement of 313 MU, the Board has purchased 258 MU only. During discussions with it, the Board was not able to provide any sufficient explanation in this regard. This again highlights the need for power purchase management that not only reflects proper peak load management but also ensures merit order dispatch.

4.65 For the current year, the Commission approves average purchase from NTPC for the months of November and December. This average is arrived after considering actual purchase from May to October 2003. However, the Commission approves power purchase from January 04 to March 04 according to the average entitlement prevailed during May to October 2003. The approved power purchase from NTPC is shown in the table below:

Table 4.17: Approved power purchase from NTPC (MU)

	Farakka	**Kahalgaon**	**Talcher**
Proposed	388	224	88
April 2003	4	3	4
Purchase during May-October 2003	98	68	139
Average purchase	16	11	23
Approved for Nov-Dec 2003	33	23	46
Approved for Jan-Mar 2004	55	45	79
Approved for FY 2003-04	190	139	268

4.66 The Board has proposed 23 MU and 29 MU from Ranjit and Chukha station respectively. However, during discussions with the Board officials and subsequent information provided by the Board on actual purchase for the first seven months of FY 2003-04, the pattern and trend of purchase differed significantly from the proposed power purchase for FY 2003-04. During the first seven months, the Board has obtained 1.4 MU from Rangit as against 23 MU proposed for the whole year by the Board. Similarly, the Board has purchased 11 MU from Chukha in first seven months as against the proposed 29 MU for the FY 2003-04. In the meeting dated 28th November 2003 it was stated on behalf of the Board that they are contemplating to purchase from Rangit and Chukha in a similar trend for the coming months. Considering the past trend and the Board's reply, the Commission approves power purchase of 2.4 MU and 19 MU from Rangit and Chukha stations for FY 2003-04 respectively. In the next tariff petition, the Commission would like to go into the detail of JSEB's share in and PLF of these plants vis-à-vis actual purchase by the Board. The proposed and approved power purchase from TVNL and Central generating stations is shown in the table below:

Table 4.18: Approved power purchase from CGS (in MU)

	Proposed	**Approved**
A. Power purchase	3994.00	3629.27
TVNL	1269.00	1603.48
NTPC	700.00	597.60
Chukha	29.00	19.12
Rangit	23.00	2.44
B. Total purchase	2021.00	2222.64
Difference (A-B)	1973.00	1406.64

DVC

4.67 The Board has proposed a power purchase of 1973 MU from DVC. The Commission believes that the Board should purchase power prudently, by following a merit order dispatch. Per unit cost of power from DVC plant is the highest, which has severe financial implications on the Board's finances. Considering the power purchase, as approved by the Commission in Table 18 and the total power purchase requirement, the Commission approves remaining power purchase requirement of 1407 MU from DVC against the proposed 1973 MU. The merit order dispatch approved by the Commission is shown in the table as below:

Table 4.19: Approved power purchase from DVC and merit order dispatch (MU)

		Proposed (MU)	Approved (MU)	Cost per unit
A	Power purchase	3994.00	3629.27	
1	Chukha	29.00	19.12	0.93
2	Talcher	88.00	264.36	1.67
3	TVNL	1269.00	1603.48	1.68
4	Farakka	388.00	186.25	1.87
5	Rangit	23.00	2.44	2.11
6	Kahalgaon	224.00	135.99	2.23
B	Total purchase	2021.00	2211.64	
7	DVC (A-B)	1973.00	1406.64	2.61

Cost elements

Fuel Consumption and fuel cost

Fuel consumption:

4.68 PTPS has entered into an agreement to purchase "D" grade coal with calorific value of 4201 - 4950 K cal /kg at an average coal price of Rs 731.64 per MT (excluding freight). However, upon enquiries by the Commission, it was found that the Board is actually getting E & F grade coal with a lower calorific value and higher ash content against the price of "D" grade coal. The Commission therefore directs the Board to undertake this matter with the linkage committee to ensure availability of "D" grade coal. The Commission also advises the Board to explore the possibility of procuring washed coal with reduced ash content to minimize the ash disposal problem. It was found that there is a transit loss of 15% while transporting coal to the power plant. Given that the PTPS is situated in a pithead such a level of transit loss is very high and is indicative of poor supervision on part of the Board. The Commission also directs the Board to step up its supervision to reduce this loss to an acceptable level.

4.69 The oil consumption rate of PTPS is very high, which is 24.31 ml/kwh for FY 2002-03 as compared to the CEA prescribed 3ml/kwh. The Board has submitted that due to repetitive tripping and forced outages, oil consumption has gone up, as the fireball and light up of the boiler has to be maintained. Add to it, is the poor quality of coal being used currently, leading to higher oil consumption.

4.70 The Commission maintains that the necessary maintenance work should have been carried out in order to minimize break-downs and to manage the operations of plant efficiently. Such a high oil consumption would therefore, not be allowed to pass through to the consumers unless it results in increased energy generation.

4.71 Overall, the Commission notes that there are numerous operational inefficiencies with regard to management of fuel consumption by the Board, and it is not only the 'old age' of plant, which is responsible for poor performance, as had been held by the Board. The Commission directs the Board to undertake appropriate measures with proper fuel management system in place to improve the efficiency of plant and submit an action plan in this regard within one month from the date of issue of this order.

Fuel cost

4.72 PTPS is a thermal plant and uses coal as the main fuel. The Board has proposed a coal consumption rate of 0.955 kg/kwh for PTP station. The Board has estimated total fuel cost at Rs.143 Crore. The Board has taken into account the price of fuel of the previous year to project total fuel cost for FY 2003-04.The per unit cost thereon has been proposed at Rs.1.42/kwh.

4.73 The Commission has examined the 'Monthly Progress Report' of PTPS in order to estimate the coal consumption rate. This was found to be at approximately the level as had been proposed by the Board though there's slight variation from month to month. Since the Commission is constrained by lack of data to arrive at an optimum level of coal consumption rate it accepts the rate, as had been proposed by the Board. Besides, the Commission has also accepted the average coal price of the previous year, as had been proposed by the Board, to estimate the total coal cost for FY 2003-04.

Table 4.20: Proposed fuel cost

Fuel consumption and its cost for FY 2003-04	
Primary Fuel	Coal
Generation - Mus	1189
Consumption Rate- kg/Kwh	0.955
Consumption - Quantity - Metric Tonne	1135495
Average Coal Price - Rs/MT	731.64
Average Coal Price - Rs/Kwh	0.70

4.74 While coal consumption and its cost have not shown a significant variation, the oil (FO and LDO) consumption and its cost have increased rather steeply. The Commission notes that this undue increase in oil highlights the inefficiencies that lie in the management of generation by the Board and consumers should not be burdened because of that. The Commission has examined the 'PTPS Cost of Generation Statement' for the first six months of FY 2003-04 to go over the trends in oil costs. The per unit cost of oil has doubled without any accompanied increase in generation. In fact, the cost has increased while the generation has been declining. This could be viewed from the following table:

Table 4.21: The Commission's analysis of fuel cost

	Gross Generation (MU)	**Coal Cost (Rs./Kwh)**	**Oil Cost (Rs./Kwh)**
April'03	115	0.78	0.36
May'03	103	0.78	0.64
June'03	80	0.69	0.74
July'03	86	0.76	0.64
Aug'03	68	0.75	0.70
Sept'03	80	0.76	0.60

4.75 Since increase in oil did not translate into increased generation, the Commission has approved the oil cost by benchmarking it with the lowest that had been attained in the first half of FY 2003-04. Taking into account the Rs 0.70/Kwh, as approved for the coal and Rs 0.36/Kwh as approved for the oil, the aggregate per unit cost approved by the Commission is Rs.1.06/Kwh against gross generation of 1189 MU, which translates into Rs.1.24/Kwh for a net generation of 1016 MU. This is against the proposed fuel cost of Rs.1.42 /kwh at net generation of 1014 MU. Depending on the approved per unit cost and approved net generation of 1016 MU, the Commission approves a total fuel cost of Rs.126 Crore as follows:

Table 4.22: Fuel Cost for FY 2003-04

	Proposed	**Approved**
Fuel cost (Rs./Kwh)	1.42	1.24
Net Generation (MU)	1014	1016

Total fuel cost (Rs.Cr)	143	126.06

Power purchase cost

4.76 Considering the approved quantum of power purchase from various stations by the Commission and the cost per unit incurred by the Board in the FY 2002-03, the Commission approves the power purchase cost of Rs. 758.48 Crore against the proposed Rs.938.60 Crore. The table shows the approved merit order dispatch and cost.

Table 4.23: Approved generation and power purchase cost for FY 2003-04

	Approved Merit Order Dispatch							
S. No.	**Source**	**MW**	**PLF**	**MU**	**Cumulative purchase**	**Cost**	**Transmission charges**	**Total cost**
	PTPS	585	20%	1016	1016	1.24	0.00	1.24
	SRHP	130	10%	116	1132	0.00	0.00	0.00
	Own Generation			**1132**		**1.11**		
1	Chukka	2	90%	19	1151	0.93	0.13	1.07
2	Talchar	43	71%	268	1419	1.67	0.13	1.80
3	TVNL	200	92%	1603	3023	1.68	1.68	269.39
4	Farakka	48	45%	190	3213	1.87	0.13	2.00
5	Rangit	0.4	66%	2.4	3216	2.11	0.13	2.24
6	Kahalgoan	29	55%	139	3355	2.23	0.13	2.37
	DVC			1973				2.61
7	Effective purchase from DVC			1407				
	Total Power Purchase & Cost			**3629**		**2.09**		
	Energy Cost			**4761**		**1.86**		

Employee cost

4.77 The Board has projected an employee cost of Rs 237 Crore, which includes increase in DA by 26%, Medical reimbursement by 36%, LTC by 46%, and Gratuity by 29%. In all, the Board has proposed a 48% increase in the employee cost over the FY 2002-03 level. The break up of various components of employee cost for the FY 2002-03 and the proposed estimates for FY 2003-04 are tabulated as below:

Table 4.24: Details of employee cost (Rs. Crore)

Details of Employee cost (Rs.Crore)			
Cost Component	Provisional 2002 - 03	Projected 2003 - 04	Growth rate
Pay of officer	15.10	17.09	13%
Pay of workmen	57.65	61.11	6%
DA (Officers)	7.87	10.27	30%
Da (Workmen)	29.98	36.67	22%
Salary	72.75	78.02	7%
DA	37.85	47.81	26%
Interim Relief	0.10	0.11	12%
Compensatory Allowance	0.63	0.68	9%
Special Pay	0.06	0.06	7%
Medical Allowance (Fixed)	0.29	0.30	3%

House Rent Allowance	3.58	3.94	10%
Conveyance Allowance	0.33	0.36	8%
Emergency Allowance	0.14	0.16	9%
Free Electricity	0.52	0.59	14%
Cash Handling / Steno Typist Allowance	0.01	0.02	11%
Overtime	2.55	2.82	10%
Bonus	1.71	1.86	9%
Medical Reimbursement	0.81	1.11	36%
Leave Travel Assistance	0.30	0.44	46%
Leave Encashment	3.91	4.84	24%
Payment under workmen compensation / Group Insurance	0.91	1.24	37%
Social Welfare Expenses	0.10	0.11	8%
Uniform & Liveries	0.47	0.65	38%
Group Saving Scheme	1.31	1.77	35%
Contribution to Provident Fund	0.51	0.54	6%
Gratuity	8.41	10.88	29%
Pension	22.11	25.55	16%
Honorarium / Ex. Gratia	0.04	0.06	33%
Funeral	0.01	0.02	21%
Provident Fund Compensation Charges	0.11	0.12	5%
Cont. to Officer Welfare Fund	0.18	0.30	65%
Other, if any (With Details)	0.30	0.36	16%
Group Insurance Premium	0.01	0.01	31%
Pay Revision Arrear	0.00	41.36	-
Pension Revision Arrear	0.00	11.17	-
Medical Expenses	0.08	0.08	9%
Total	**160.11**	**237.31**	**48%**

4.78 Of the Rs.237 Crore proposed as an employee cost for FY 2003-04, a provision of Rs. 52 Crore has been made towards pay and pension revision arrear alone. The Commission notes that in the past there has been no provision made in this regard. During discussions with the Board officials, it was brought to the notice of the Commission that the Board's staff has been receiving revised salaries from FY 2001-02. However, arrears have been accumulated between 1998-2001. It was mentioned that no decision has been taken in this regard by the State Government and the Board. The Commission therefore, holds that for the present year costs towards these liabilities of the Board would not be passed through to the consumers.

4.79 A large number of consumers have objected to the tariff increase on the ground that employee costs of the Board are very high. According to them, this reflects inefficiency of the Board and it is incorrect to pass on the burden of this cost to the consumers. The objectors have stated that the number of employees in FY 2002-03 has increased by 20% over the previous year level and the finances and operations of the Board do not allow this luxury at the expense of consumers.

4.80 The Commission has analysed the employee cost structure of the Board and notes that the employee cost of the Board is extremely high. The table below provides a comparison of employee cost per unit of electricity sold, as approved by a number of State Electricity Regulatory Commissions. In all these states the Board has not been broken up thereby offering a reasonable basis for comparison.

Table 4.25: Employee Cost approved by the various Commissions in FY 2002-03*

Boards	**MP2**	**West Bengal1**	**Delhi 2**	**Gujarat1**	**Punjab 3**	**Maharastra2**	**Jhar**

Emp.cost (Paise/Unit)	29.63	42.36	39.75	25.16	57.15	46.05	65.0(

Source: Tariff orders

1 Employee cost for the FY 2000-01

2 Employee cost for the FY 2001-02

3 Employee cost for the FY 2002-03

*Employee cost and sale in FY 2002-03

To a certain extent the reason for high employee cost per unit is lower quantity of energy sold and if the sales is increased the per unit employee cost will reduce. But even if the number of employees per consumer is considered, the ratio in Jharkhand is high. The number of employees per unit sold is the highest whereas the number of consumers served by each employee is very low. The comparison is tabulated as below:

Table 4.26: Comparison of various states (FY 2000-01)

	Sales (MU)	**No. of Consumers**	**No. of Employees**	**Consumer per employee**	**Number of Employees per unit of sale**
GEB	31435	7100000	47782	148.59	1.52
MP	25571	8140000	88572	91.90	3.46
Del	9154	3200000	24700	129.55	2.70
MAH	41598	12980000	111724	116.18	2.69
WB	10000	3570000	36217	98.57	3.62
Jharkhand*	2481	629127	9500	66.2	3.83

Source: "Annual Report on the working of SEB & ED, May 2002", Planning Commission

*For FY 2002-03

4.81 Though the states might not be fully comparable the aforementioned table indicates the severity of inefficiency. The Commission considers that this problem needs to be approached from both ends - reducing employee costs and increasing sales per employee. Presently the Board is resorting to load shedding even when power is available. This is being done because the purchase of electricity at the margin is found to be too expensive. The only way out is to increase sales by either increasing generation of the JSEB or by availing maximum possible power from TVNL or by locating cheaper sources of power outside the State or from Central PSUs. Simultaneously it needs to be ascertained as to where exactly does the JSEB have surplus manpower and what can be done to reduce this burden.

4.82 For FY2003-04, except for DA, the Commission approves an increase of 3.4% for all the components of employee cost, which is the annual inflation rate (Wholesale Price Index) as of March 2003 over the FY 2002-03 levels. This is on the basis of actual incurred cost for FY 2002-03 and allowing some increase over this as may be required to compensate for inflation. As DA is given twice in a year, the Commission approves 6.8% increase over FY 2002-03 levels. The approved employee costs are tabulated as below in Table 27:

Table 4.27: Approved employee cost for FY 2003-04 (in Rs.)

Details of Employess Cost			
			Commission

Sl.No.	Particulars	Projected	Approved
		2003-04	2003-04
1	Pay of officer	170885042.00	156100317.45
2	Pay of workmen	611125285.00	596121733.77
3	DA (Officers)	102673035.00	84046364.66
4	DA (Workmen)	366680964.00	320197505.06
1	Salary	782010327.00	752222051.22
2	DA	469353999.00	404243869.73
3	Interim Relief	1146000.00	1059062.09
4	Compensatory Allowance	6810040.00	6476311.14
5	Special Pay	625000.00	602822.00
6	Medical Allowance (Fixed)	3034800.00	3034790.00
7	House Rent Allowance	39394484.00	37048826.96
8	Conveyance Allowance	3601100.00	3442082.60
9	Emergency Allowance	1566329.00	1489247.45
10	Free Electricity	5933000.00	5383004.00
11	Cash Handling / Steno Typist Allowance	157200.00	146149.70
12	Overtime	28190000.00	26398456.35
13	Bonus	18593000.00	17674162.00
14	Medical Reimbursement	11070000.00	8426388.61
15	Leave Travel Assistance	4374000.00	3094762.00
16	Leave Encashment	48392000.00	40444930.68
17	Payment under workmen compensation / Group Insurance	12400000.00	9383550.00
18	Social Welfare Expenses	1080000.00	1036357.52
19	Uniform & Liveries	6454200.00	4841188.00
20	Group Saving Scheme	17661000.00	13515414.00
21	Contribution to Provident Fund	5380000.00	5249773.10
22	Gratuity	108815000.00	87005930.00
23	Pension	255451291.00	228577811.24
24	Honorarium / Ex. Gratia	594000.00	462198.00
25	Funeral	179000.00	153032.00
26	Provident Fund Compensation Charges	1165000.00	1151565.80
27	Cont. to Officer Welfare Fund	3002000.00	1878261.00
28	Other, if any (With Details)	3551900.00	3152934.84
29	Group Insurance Premium	85000.00	67210.00
30	Pay Revision Arrear	413577700.00	0.00
31	Pension Revision Arrear	111661400.00	0.00
32	Medical Expenses	816000.00	776534.00
	Total	1840885670.00	**1668438676.02**

Repair and Maintenance (R&M) cost

4.83 The Board has proposed an expenditure of Rs. 48 Crore towards Repair and Maintenance expenses for FY 2003-04.This represents an increase of approximately 12% as compared to FY 2002-03. The expenses with regard to each sub-component under this head have been revised upwardly with few of them increasing steeply. According to the Board, this level of expenditure is essential to ensure maintenance of quality of supply to the consumers.

4.84 The Commission agrees that R&M expenditure is essential for ensuring quality of supply to the consumers and believes that the proposed increase of 12% is reasonable. However, the Commission would like to highlight that the approved increase should result into increased generation and improved quality of supply.

Table 4.28: Approved R&M cost for FY 2003-04 (in Rs.)

		Provisional	**Approved**
	Details of Repair and Maintenance	2002 - 03	2003 - 04
1	R&M Plant & Machinery	251826000.00	262900000.00
2	R & M Buildings	34600000.00	41000000.00
3	R & M Civil Works	18540000.00	28074000.00
4	R & M Hydraulic	7207000.00	7500000.00
5	R & M Lines, Cable, Network	114100000.00	135100000.00
6	R & M Vehicles	6807901.00	7595000.00
7	R & M Furniture & Fixture	1153000.00	1837000.00
8	R & M Office Equipments	938000.00	1589000.00
9	Technical Fees	100000.00	200000.00
	Total	435271901.00	485795000.00

Administration and General (A&G) cost

4.85 The Board has proposed A&G cost of Rs. 36 Crore for the FY 2003-04, which includes sharp increase in consultancy expenses and books & periodicals expenses. The Commission accepts the reduction in electricity and water charges and minor increase in expenses related to printing, stationery and bank commission. However for other expenses under A&G, the Commission has approved the expenditure on the basis of expenditure for FY 2002-03 adjusted for inflation (at the rate of 3.4%). The approved A&G expenses for FY 2003-04 is tabulated as below in Table 29:

Table 4.29: Approved A&G cost (in Rs.)

	Details of Administrative Cost	**Provisional**	**Projected**	**Approved**
		2002 - 03	2003 - 04	2003 - 04
1	Rent (Including Lease Rental)	18241796.00	23483076.00	18862017.06
2	Insurance	11800000.00	16085000.00	12201200.00
3	Telephone, Fax, Mobile	13862545.00	20637000.00	14333871.53
4	Postage, Telegram	2515190.00	2925000.00	2600706.46
5	Legal Charges	11893000.00	14617000.00	12297362.00
6	Audit Charges	6000000.00	8000000.00	6204000.00
7	Consultancy Charges	13100000.00	25660000.00	13545400.00
8	Conveyance Expenses	1151000.00	1321000.00	1190134.00
9	Travelling Expenses	10865000.00	15400000.00	11234410.00
10	Vehicle Running (Light), Petrol & Oil	10450000.00	12380000.00	10805300.00
11	Vehicle License & Registration	1630103.00	1696000.00	1685526.50
12	Fees and Subscription	525000.00	530000.00	542850.00
13	Stores Handling	2320101.00	2589000.00	2398984.43

14	Books & Periodicals	431500.00	1253600.00	446171.00
15	Printing & Stationary	31410768.00	31540000.00	31540000.00
16	Advertisement	13196000.00	15165000.00	13644664.00
17	Electricity & Water Charges	24297000.00	20610000.00	20610000.00
18	Entertainment	2378000.00	2898000.00	2458852.00
19	Pvt. Security Guards / Home Guard	62032400.00	70564000.00	64141501.60
20	Computer Agency	23442000.00	33500000.00	24239028.00
21	Freight & Other purchase Related to Expenses	9448750.00	12970000.00	9770007.50
22	Vehicle Running (Heavy), Diesel, Petrol, Oil	5147210.00	5443000.00	5322215.14
23	Miscellaneous Expenses	8651889.00	11263000.00	8946053.23
24	Bank Commission	735000.00	759000.00	759000.00
25	Bill Distribution Expenses	2940000.00	3275000.00	3039960.00
26	Training	1220000.00	1742000.00	1261480.00
27	Pollution	2200000.00	2420000.00	2274800.00
28	Vehicle Hire Expenses	5760025.00	7493000.00	5955865.85
29	Rates & Taxes	380000.00	441000.00	392920.00
	Total	298024277.00	366659676.00	302704280.31

Bad Debt provision

4.86 The Board has proposed a provision of Rs.186 Crore towards bad and doubtful debts for FY 2003-04. The Board has calculated this considering 10% of the total dues net of Government sector dues. During discussions, the following clarifications were sought from the Board

a) Whether the Board has any policy and rules for classifying a receivable as bad debt and the procedure followed in this respect.

b) Whether any bad debts have been written off in its books of accounts.

4.87 It was mentioned by the Board that the erstwhile BSEB had a policy for making such provision in accounts, which is still in force. It may however be noted that during discussions with the Board, it was mentioned that neither the BSEB nor the JSEB have any rules for classifying a receivable as bad debt. To the second question, the JSEB stated that it has not written off any bad debts in its books of accounts. In view of the fact that no bad debts have been written off, which in some manner is reflective of the lack of a clear policy and procedure, no bad debt either for past years or for FY2003-04 is allowed.

4.88 Further, it may be seen from the figures provided by the Board that in FY 2002-03 about 11% of the billed amount is not collected i.e. Rs.98 Crore. The Commission would like to highlight that unless individual officers are made responsible for either writing off arrears with full justification or for collecting these arrears, there is not going to be much improvement in the collection efficiency. Many objectors have also pointed out that there are huge amounts of dues outstanding against the Government organisation and departments. The Commission directs the Board that they should put a mechanism in place that ensures that revenue is collected more expeditiously so that the precarious position of the Board's cash flow improves. Finally the Commission has also provided separately an interest on working capital to make up for the shortfall in collections assuming a collection efficiency of 95% in FY 2003-04. The Commission believes that opportunity cost on the uncollected revenue need to be discounted through this provision. In view of the above the Commission has not allowed any provision for bad debts. The savings on this account for FY2003-04 are thus Rs.183 Crore.

Depreciation

4.89 The Board has proposed a depreciation of Rs. 73 crore for FY 2003-04, which according to the Board is calculated on the basis of straight-line method. The Board submitted that the liability in this regard might as well change depending upon the final settlement of accounts between the two Boards. This however, represents an increase of over 6% from the previous year's level.

4.90 The Commission was constrained to determine the right amount for depreciation because of the following reasons:

a) Settlement of accounts between the BSEB and JSEB is still not finalized.

b) The Board has not maintained any Fixed Assets register.

c) The Books of accounts are still not audited. Only provisional account for FY 2001-02 is available.

4.91 During discussions with the Board, it was inquired whether the Board has been maintaining an asset register classifying the assets on the basis of the notification issued by the Ministry of Power. The Board has stated that the same is not available. This is important since different assets have different rates of depreciation. The Commission believes that the Board should classify its assets according to the notification issued by the Ministry of Power and claim depreciation according to the rates prescribed in this notification.

4.92 The Commission has also verified the depreciation amount from the provisional accounts for FY 2001-02. The Commission notes that in the petition the depreciation amount shown is Rs. 68.7 Crore whereas in the provisional account it is Rs. 59.9 Crore for FY 2001-02. The Commission is of the view that since there is no cash flow involved, the Commission would not allow the full amount as proposed by the Board to be pass through in tariff in the current year. Till the accounts are audited and settlement of accounts between the BSEB and the JSEB is finalised, the Commission only approves depreciation amount of Rs. 59.9 Crore for FY 2003-04 as was reflected in the provisional accounts of FY2001-02.

Interest and finance charges

4.93 In the first tariff petition the Board has proposed an interest and finance charge of Rs.258 Crore after considering 13% interest on the 25% liabilities of the erstwhile BSEB. During discussions with the Board, it was brought to the notice of the Commission that since the bifurcation issue is still not resolved the Board has not been paying any past liability. In the revised petition, the Board has reduced the proposed interest amount to Rs.158 Crore for FY 2003-04, without providing sufficient explanation in the petition except that the implication of this huge interest cost on tariff would be very high.

4.94 The Commission also inquired about the purpose for taking various loans and the interest rate applicable on these loan amounts. The Board was not able to provide any explanation in this regard and stated that they have considered 13% interest rate across all loan liabilities.

4.95 Since the matter on bifurcation is still not clear, the Commission is unable to take any view on the quantum of the loan and on the nature and extent of its interest liabilities prior to the bifurcation of the BSEB. However the Commission has created a temporary contingency reserve for unforeseen expenses arising out after the settlement of bifurcation issue and the accounts are audited. Meanwhile, the Commission has considered loans that the JSEB has taken since FY 2001-02. The loan amount taken after bifurcation is shown in Table 30 as below:

Table 4.30: Loans given by state government in FY 2001-02 and FY 2002-03

	2001-02	**2002-03**
Generation	20	0
Transmission	40	61

Distribution	25	25
Building	2	0
MNP	0	34
APDRP loan	0	6
Loan	87	126

4.96 The Board has stated that they are paying 13% interest rate on these loans. The Commission accepts the interest rate and accordingly approves interest amount of Rs. 27.69 Crore for FY 2003-04. Apart from this, the Commission also approves Rs. 6.29 Crore as interest on working capital for meeting shortfall in revenue collection by 5%. This has been calculated after applying 13% interest rate on 5% of the approved revenue from tariff in FY 2003-04.

Statutory return

4.97 The Board has proposed Rs.13.82 Crore towards statuary return of 3% on a net block of Rs. 460 Crore. The Board has mentioned that the return on capital base is calculated as provided under the Section 59 of the Electricity (Supply) Act, 1948. However, objectors have raised concern about the validity of proposing a return when it appears that fixed assets have not been segregated between the JSEB and the BSEB till date. The Commission has also been constrained with this uncertainty to verify the capital base.

4.98 Further, the Commission believes that the Board should make efforts to improve its productivity on various accounts. As discussed earlier, the Commission has approved a 5% reduction in T&D losses against the proposed reduction of 10%. The remaining 5% reduction that can bring Rs.104 Crore per annum is more than enough to recover the proposed return amount. Apart from this, the Board should make efforts to increase the PLF of its plants, which would help in reducing power purchase quantum and cost. Likewise, the Commission would expect that other costs be further rationalized by working towards a benchmarked minimum, which would also help the Board to generate additional revenue. The provision for making surplus can only be made after such productivity gains are achieved. Therefore, the Commission while recognizing the need for the statutory return of Rs.13.82 Crore, is not passing this through the tariff. This shall be considered in future depending on the improvement in productivity, among other things.

Revenue Requirement and Temporary Contingency reserve

4.99 The total revenue requirement, as approved by the Commission after incorporating the above changes, is thus Rs 1224.08 Crore in comparison to the projected revenue requirement of Rs 1848.65 Crore by the Board. As discussed earlier, the Commission is uncertain about certain liabilities and therefore has approved Rs.110 Crore, as temporary contingency reserve for meeting unforeseen liabilities. It has been created to meet the liabilities arising because of:

a) Settlement of accounts on bifurcation of assets and liabilities between the BSEB and the JSEB, which might raise certain interest liability.

b) Auditing of accounts.

c) Fresh capital expenditure incurred for either upgrading the transmission line for improving evacuation from TVNL and PTPS or for improving generation in PTP station.

4.100 However, the Board could avail this reserve only after submission of documents and proof of an unforeseen expenditure and shall not transfer money from this account without prior approval of the Commission. The Commission directs the Board to come up with a new petition for FY 2004-05 removing the various data deficiencies highlighted throughout the petition. The Commission also directs the Board to audit the books of accounts for FY 2001-02 and FY 2002-03 and submit the same to the Commission by March 2004.

4.101 Net Revenue Requirement and Revenue gap: The Gross revenue requirement after including temporary contingency reserve is Rs. 1334.08 Crore. Net revenue requirement after excluding approved revenue from non-tariff income of Rs.336.04 crore is Rs.998.07 crore. Considering the revenue from current tariff of Rs.966.29 Crore, revenue gap is Rs.31.78 Crore. This could be recovered either through tariff rationalisation or direct subsidy from the Government. This has been discussed in the chapter 5. The costs proposed by the Board vis-à-vis the approved levels by the Commission are tabulated as below:

Table 4.31: Approved revenue requirement for FY 2003-04

Revenue Requirement (Rs. Cr)						
	Items	ARR submitted	Commission Approved	Difference	Rs./unit of sale (prop)	Rs./unit of sale(app)
A	Power Purchase	938.60	758.48	180.15	2.97	2.78
B	Generation Cost	162.21	126.06	36.15	0.51	0.46
C	Repairs & Maintenance	48.57	48.57	0.15	0.18	0.18
D	Employees Cost	237.31	166.84	70.47	0.75	0.61
E	Admn. & General Exps.	36.67	30.27	6.40	0.12	0.11
F	Depreciation	72.98	59.90	13.08	0.23	0.22
G	Interest and Finance Charges	152.41	27.69	124.72	0.48	0.10
H	Prior Period Expenses	-	-	-	-	-
I	Bad Debts Provision	186.08	-	186.08	0.59	-
J	Interest on working capital	-	6.29	(6.29)	-	0.02
	Total Expenditure	1,834.83	1,224.11	610.75	5.80	4.48
K	Statutory Return	13.82	-	13.82	0.04	-
	Revenue Required	1,848.65	1,224.11	624.57	5.84	4.48
	Temporary Contingency Reserve		110.00	(110.00)		0.40
	Gross Revenue requirement	1,848.65	1,334.11	514.57		4.89
L	Less: Misc. Receipts	321.83	336.04	(14.21)	1.02	1.23
M	· Other Income	-	-	-		
N	· Prior Period Income	-	-	-	-	-
	Net Revenue required	1,526.82	998.07	528.78	4.82	3.66
	Revenue at current tariff		966.29			
	Revenue Gap		**31.78**			